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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

November 5, 2008

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE ON PLANT LICENSE RENEWAL

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VOGTLE ELECTRIC GENERATING PLANT

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WEDNESDAY, NOVEMBER 5, 2008

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The meeting came to order at 1:30 p.m. in room T2B3 of Two White Flint, Rockville, Maryland. John Sieber, Chairman, Presiding.

PRESENT:

JOHN D. SIEBER CHAIRMAN

GEORGE E. APOSTOLAKIS MEMBER

DENNIS C. BLEY MEMBER

MARIO V. BONACA MEMBER

CHARLES H. BROWN, JR. MEMBER

OTTO L. MAYNARD MEMBER

HAROLD B. RAY MEMBER

MICHAEL T. RYAN MEMBER

JOHN W. STETKAR MEMBER

JOHN J. BARTON CONSULTANT

CHRIS BROWN DESIGNATED FEDERAL OFFICIAL

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

1:30 p.m.

CHAIRMAN SIEBER: The meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee. I am Jack Sieber, Chairman of the Vogtle Electric Generating Plant License Renewal Subcommittee. ACRS members in attendance are Otto Maynard, myself, John Stetkar, Bill Shack, Mario Bonaca, Mike Ryan, Harold Ray, Charles Brown, and our Consultant John Barton.

I would point out that Mr. Barton has submitted to us his consultants report dated 10/30 which was, to my knowledge sent to all the members. I got copy of it.

There is a second report which I did not get until today dated October 31st and that can be made available to you during or after the meeting.

The purpose of this meeting is to review the license renewal application for the Vogtle Electric Generating Plant, the draft safety evaluation report, and the associated documents.

We will hear presentations from representations of the office of nuclear reactor regulation and the applicant Southern Nuclear Operating Company.

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

The rules for participation in today's meeting were announced as part of the notice of this meeting previously published in the Federal Register on October 22, 2008. We have received no written comment or request for time to make oral statements from members of the public regarding today's meeting.

The transcript of the meeting is being kept and will be made available as stated in the Federal Register notice. Therefore we request that participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee.

Participants should first identify themselves and speak with sufficient clarity and volume so that they may be readily heard. Each of us has received an application, I think most of us on a disk, but I got one as a printed version probably due to my age and I have reviewed the application and I found it pretty well done.

We also received the safety evaluation

report from the staff. I would point out that the safety evaluation report at this stage, at the subcommittee meeting stage is a draft and actually there are two parts. We've got one part on a disk, the second part was sent to us by email.

And unfortunately it was beyond the time for our ordinary review process which we expect to improve on. And we also got three pages of comments on our ACRS staff engineers.

The license application for renewal that we are to discuss today will follow the requirements of Title 10 Code of Federal Regulations Part 54 and I would point out that the Vogtle Plant Unit 1 is older than Unit 2 by two years. Unit 1 qualifies for the at least 20-year lifetime for application for license renewal. Unit 2 does not and therefore requires an exemption from Part 53 which I understand the staff is suggesting be approved.

I would like to -- as I look around the audience welcome members of the Beaver Valley Power Station staff who are here to watch what happens to Southern Nuclear Operating Company because I think they are next up for license renewal. And so I welcome the Beaver Valley staff to our meeting here.

I'd like to now proceed with the meeting and I call upon Brian Holian of the Office of Nuclear Reactor Regulation to introduce both the staff and the applicants presented, Brian.

MR. HOLIAN: Good afternoon, thank you Jack. My name is Brian Holian, I'm the Director of the Division of License Renewal. I'd like to make some quick introductions of the staff and turn it over licensee.

This is the third application from Southern Company for license renewal. They successfully received a license for Hatch Farley and now coming before the staff for their final Plant, Vogtle.

To my immediate right is Dave Pelton, the Branch Chief responsible for the Vogtle Plant. To his right Dr. Sam Lee, the Deputy Director in License Renewal. And to the far right Donnie Ashley, the Senior Project Manager who has been in charge of the License Renewal Application in house.

There's one other individual in from Region II that I wanted to highlight in the back row, and that's the Senior Reactor Engineer Louis Lake from Division Reactor Safety in Region II responsible for inspection of the Vogtle Plant. You'll be hearing a lot more from both Donnie and

Louis after licensee's presentation. Now with that I'd like to turn it over to Chalmer Myer, the Project Manager for License Renewal for Southern Company.

MR. MYER: Thank you Brian. As I said I'm Chalmer Myer and we are here and we appreciate the Chairman and ACRS members the opportunity to present our application to you this afternoon.

To go over my agenda first one of the things I want to do is introduce everybody from Southern Nuclear that's here today and we'll be providing a description Vogtle and a current operating status.

I'll provide highlights of the license renewal project and how we apply the GALL process. There were a couple of items that came up in Region II that we are going to address what actions we're taking and how these will be addressed during the license renewal in the future as well as current Plant operations.

For introductions I'd like the gentlemen at the table to introduce themselves.

MR. MANSFIELD: My name is Lee Mansfield, I'm the Engineering Support Manager of Plant Vogtle.

MR. TINER: My name is Todd Tiner, I'm the Site Vice President at Plant Vogtle.

MR. MYER: In our audience we have David Jones, David is our Vice President of Engineering for Southern Nuclear, and Mark Ajiluni. Mark is our Licensing Manager in Southern Nuclear. And Todd Youngblood, Todd is the Engineering Director at Vogtle. And Mike Macfarlane, Mike was the previous Project Manager for License Renewal. So we brought him in to answer any of the tough questions.

And next to him is Wayne Lunceford, he's our Mechanical Representative. Partha Ghosal, Partha is our Civil Representative. And until a few months ago he was the Chairman of the NEI Civil Structural Working Group for License Renewal.

Cary Martin is our electrical representative. John Hornbuckle is our PLAA representative and KC Harriston is an Attorney through Balch and Bingham who supports our project. And Lou Bohn is another mechanical representative, he's also up here running our backup slides. We have a slide for our presentation.

Vogtle is located in Burke County, Georgia near the Savannah River. The -- it is a two unit site. They are essentially identical. Westinghouse four Loop, PWR's they are currently rated for 3625 megawatts electrical.

This represents a recent power uprate for measurement and certainty recapture of 1.7 percent. Both units are at approximately 1,250 megawatts electric.

The ultimate heat sink for the plants are the nuclear service cooling water towers. These are seismic category one concrete structures with basins that hold all the water necessary for failed heat sink.

The Turbine Plant cycle cooling is provided by natural draft hyperbolic cooling towers. They make up for the -- the hyperbolic towers is from the Savannah River and make up to the ultimate heat sink is through well water.

The Plant was originally licensed to Georgia Power Company. But the current licensee and operator is Southern Nuclear Operating Company. Plant owners, primary owner being Georgia Power Company and other owners are Oglethorpe Power Corporations, the Municipal and Electric Authority of Georgia, and the City of Dalton, Georgia.

The licensing history for Vogtle the key elements. We have a construction permit in 1974 and we received our operating license in 1987 for unit 1, in 1989 for unit 2. We implemented a stretch power uprate of 4.5 percent in 1993 and as I stated then we transferred the license to Southern Nuclear Operating Company in 1997.

We submitted our license renewal application in June of 2007. And while that application was in review we submitted and received approval for our measurement uncertainty recapture uprate.

The current operating licenses will expire in 2027 and 2029 for units 1 and 2 respectively. This is a two added year for Vogtle. We completed our 14th refuel outage of unit 1 in April of this year and just completed our 13th refueling outage for unit 2 this last month.

MR. BARTON: How long were those outages?

MR. MYER: Tom?

MR. MYNAN: The unit 1 outage was approximately 40 days. Major drive over the unit 1 outage was the structural well overload project that we completed on Vogtle unit 1.

Unit 2's outage, the counting is still

out on it but I think it was 37 days and five hours was the duration of the Fall outage. The original duration for the outage was approximately 28 days. So we had some challenges with the outage.

MR. MYER: As I said, both units are currently at 100 percent power. The 18 month capability factor for unit 1 is 92 percent and a little over 90 percent for unit 2.

Now, we'll present our license renewal project. I really won't touch on the exemption for 5417 C since Dr. Seiber has already talked about that.

I want to talk about a project team and how the strength of the team has led to our success. We did take advantage of our past experience with Hatch and Farley. Then I'll give some highlights of our scoping and AMR and AMP programs in how we apply GALL to the programs.

I'll spend a little bit of time talking about the types of exceptions we had to our Aging Management Programs to help you understand those.

One area that's had a lot of discussion I'm sure you're interested in is how we're addressing the metal fatigue and time limit aging analysis. So, we'll talk about that for a few minutes. And then talk about how we're implementing commitments to ensure that license renewal is carried on beyond the period of extended operations.

As Dr. Seiber pointed out we received an exemption from 10 CFR 54.17 C based on similarity between unit 1 and unit 2. And unit 1 did have over 20 years of operation prior to the application being submitted.

MEMBER MAYNARD: Can I ask why you felt it necessary to apply before the unit 2 got into the window there?

MR. MYER: Yes, we have a team that had completed the Hatch and Farley and in order to keep the team together we needed to move right into Vogtle. It would have been 2009 before we could submit on unit 2. We didn't get an exemption. And to keep the team together and apply that experience we requested the exemption.

As I said our license renewal team primarily consisted of personnel that had done Farley, and also several had done Hatch. I don't have the exact numbers on the ones that had worked on Hatch. But about two-thirds of our team had worked on Hatch and about 90 percent of the team had worked on Farley.

Somebody gave me a count today that totaled license renewal experience at the point that we submitted our application for Vogtle was a 140 years of license renewal experience on the team. So there was considerable experience there.

We added Vogtle myself included in order to apply the knowledge of Vogtle and ensure that the Vogtle needs and plant processes were incorporated. Not only did we bring in that experience at the end of Farley we performed a self-assessment to identify lessons learned or things that we'd like to do better because Farley was a pretty great success, but we didn't want to set on our laurels on that. So we did self-assessment identified the number of improvements and moved on into Vogtle.

And on top of that recognized changes going on and continually changing in license renewal we have stayed abreast of what's going on in the industry. We've had members on all of the Working Groups that I pointed out that one of our members, one of our team members was a chairmen, I think we've had others through the course of the recent years that were chairmen on different committees.

I've been on the License Renewal Task force and many of you may recognize me because I've been to many of these meetings seeing what goes onto make sure we were prepared.

Additionally, we participated in a number of inspections and audits of our peer plants. So we understood what the NRC was looking for when they came out to do audits and inspections and we supported peer reviews of numerous applicants in the process of developing our applications.

So we knew what they were doing and knew and went back and made certain we addressed the same types of issues they were addressing.

In order to ensure that Vogtle was brought into this process -- and we have corporate owners as well as site owners. We had program owners all review their programs prior to submitting the application. We received a number of comments and incorporated them before the application went in.

And the program owners were deeply involved in all of the audits and inspections and basically all the comments that came from the NRC were responded to by program owners themselves so they are brought into what's been going on in the future.

We just wanted to highlight that we feel that all of these activities that we were doing to keep our team strong were shown to be successful by the fact that we've got a SER with no open items and no performatory items. We worked very hard to ensure that we respond to the NRC questions and comments.

Scoping highlights, we performed our scoping consistent with the NEI 9510 revision six. And revision six was endorsed by the NRC in red guide 1.188 revision one. We used a conservative spaces approach A2 scoping which is consistent with a lot of applicants, I'm not certain all.

But it's basic approach basically says that any non-safety related components or structures located in a space for safety related components and structures is included in the scope regardless of relative location of it's components.

Space is defined as a area that is bounded by walls, ceilings, and floors. One of the lessons learned that we brought out of Farley was to include A2 scoping on our mechanical number drawings and in addition to A1 and A3. It helped us to identify in scope components as well as assist with the NRCS's review of scoping greatly because it was all in one drawing.

And another area of discussion that's been pretty active recently has been station blackout scoping. So I just wanted to address for Vogtle, station blackout scoping or systems structures and components is consistent with the NRC's staff guidance and is consistent with the revisions to the ISG's that are under review currently.

MR. HOLIAN: Was it that way originally or did you have some discussions?

MR. MYER: It's been that way every since they submitted it. Our electrical engineers saw what was happening and actually were in agreement with the direction the staff was looking for Vogtle. So they implemented that originally.

MR. HOLIAN: Good.

MR. MYER: Aging management reviews, again we followed the NEI 9510 guidance. We made extensive use of GALL, that's something I didn't mention earlier is that during the revision to GALL our personnel were very deeply involved with it.

In fact, we had one who wrote the draft of one of the sections of comments for NEI. And so we were thoroughly familiar with it and made extensive use of it. We also were very strict in our application of whether we would call ourselves consistent.

If we didn't force fit anything we ended up with 86 percent consistency with GALL. The non-consistent items are primarily -- we had material environment and aging effects. Primarily environment or aging effect is not in GALL.

Looking at these a lot of those will probably be picked up in revision to GALL. But some of them are just unique to Vogtle and I'm not certain would warrant being picked up in GALL and I think other applicants also will have unique environments or aging effects that won't go into GALL.

MR. HOLIAN: Well, what could have got my curiosity is the nitride-induced stress corrosion cracking from to exposure to auxiliary compound cooling water. And I wonder if somebody could tell me what's unique about your cooling water and this whole phenomena which is a new one to me.

MR. MYER: Well, the interesting thing is we are not unique except that we classified it as stress induced IGSCC, that's easier for me to say the letters.

It has occurred at other sites and they

did not conclude that it was IGSCC but the phenomenon was the same.

MR. HOLIAN: Well how did you finger the nitride as the guilty party?

MR. MYER: There are some industry papers that have been written on carbon steel IGSCC and nitride has been the primary cause looking at the various chemistries. I don't have all of the background, it's been a long time since I read all of the research.

But back when this was first happening I was throughly familiar with it. And I went through -- the odd thing is I went through all of the chemistry reports for unit 1 and unit 2 because this has only occurred on unit 2. Our chemistry has been identical and we have actually had excellent maintenance of our nitrates and nitrides on both units.

So, that in itself would not have been the cause. But there are other agents that feed into this. One of them is an organic substance, plus you have to have high temperature, plus you have to have high stresses.

And we have not concluded as to what the cause was. But something is unique in unit 2 where we have some organic products as well as all of the others coming together.

And in particular it has been in high temperature areas that this has occurred such as let down heat exchange and down surge heat exchange. I think there may have been a couple of others, but it's typically going to be where the pipe is warmer than other areas.

I won't name other Plants, but there were other plants who have gone through the same thing and replaced the pipe, replaced the components and they just didn't call it this.

MR. HOLIAN: Do change material when you replace the pipe?

MR. MYER: We don't change the material. But we have instituted better weld control. A lot of the problems have been on pipe welds where we have backing rings. So the welding no longer allowed backing rings.

We replaced the let down heat exchanger and we went through a lot of stress relief on the welds to ensure that their -- the stresses were not as high. So we're basically taking measures in our construction processes to ensure that some of the factors that feed into this aren't there.

Our license renewal program resulted in 38 Aging Management Programs at Vogtle, 24 of these were existing and 15 of those required enhancements to meet license renewal requirements. We have 14 new programs at the Plant.

Of the 38 programs 27 of them have been for GALL programs and those that were GALL programs would have only minor exceptions and I'll talk about those in a moment.

Of the 11 class specific programs to the extent possible we still use GALL attributes and defining them. But they were enough different from GALL that we called them Plant specific.

Our exceptions fell typically into these four areas. I think the first one has been commonly brought up before the committee. The use of a different code of standard. GALL currently identifies specific revisions, specific code years of various standards.

For example, the upper standard that we use for steam generators, they have a specific revision. Inevitably, those standards are going to evolve to incorporate lessons learned, new technologies, and Vogtle's intent is to stay at the forefront of maintaining their equipment with the latest standards and the latest codes. In fact, some of these are even mandated by the regulatory requirements.

And so at the time we submitted the application a number of these programs were using later codes of standards than were called out in GALL. They actually in many cases exceeded what was called out in GALL, but they are exceptions.

We were fairly conservative in calling out what were exceptions. If we exceeded GALL we called it an exception. And a number of the things I want to point out is where we exceeded what's called out in GALL.

In the area of managed material or environment not in GALL this is specifically where we identified exceptions that were beyond GALL. We have stainless steel that we included in our very piping program. The GALL program doesn't have stainless steel in it.

We also included aluminum and elastomers in our external surfaces monitoring program that were not in the GALL program.

The amp scope differences. There were a number of types of amp scope differences. Again, some times it was beyond the requirements of GALL.

Our floor accelerated corrosion program we include locations that can't be modeled in that program which is beyond GALL.

We also include locations that are subject to wear by methods other than fact in our fact program. One area that we have less scope is that we didn't include our main steam nozzles because of the high sink quality in our sink generators.

Then the last was the use of alternative inspection methods. A couple of examples of this, our FAC program allows for opportunistic visual inspections to identify areas where FAC is occurring that may not have been identified otherwise.

If they open up a valve and see where the downstream of the valve and it's not in the FAC program or it's not subject to inspections in this term they will factor that back into the inspection program. That's actually in -- consistent with inset guidance for the FAC program.

Another area was our selective leaching program. Recognizing that this is an area where a lot of technology could be developed in the future. We have maintained the ability to implement new methods as technology develops in the future. This is an area where EPRI is working pretty vigorously on for the industry right now.

MR. BARTON: I have a question on starting any measurement programs. The section on loss and materials due to pitting and corrosion, partially encased, enclosed stainless steel tanks with exposure to oil or water. I understand your construction to stainless steel line tanks within concrete.

But, the question I've got is is there any Aging Management Program in place for the internals of those things, diagrams, etcetera. I couldn't find that?

MR. MYER: Could you address that. I believe the diaphragms were --

MR. MANSFIELD: I thought I saw them. I think we have a program for the diaphragms.

MR. MYER: We have a program, but I don't --

MR. BARTON: Okay.

MR. MYER: -- but I don't think it's in license renewal, because were they short term?

MR. BOHN: The tank diaphragms are included in the periodic surveillance and preventative maintenance activities.

MR. MYER: Okay, all right.

MR. BOHN: As far as the tank internals we got water chemistry, off the top of my head that's all I remember right now. I'd have to look at the specifics.

MR. MACFARLANE: This is Mike Macfarlane from Southern Nuclear. The tank diaphragms was actually a lesson learned out of Farley.

In fact, that came up in our regional inspection and we carried that forward into Vogtle. Including that was actually something that was added a little later in the game on Farley. Not all tanks have the diaphragm though, so there's --

MR. BARTON: I understand that.

MR. MACFARLANE: Okay.

MR. MYER: As I noted, the time limit on aging analysis for metal fatigue has gotten a lot of attention lately. There's a draft risk on the street that addresses a methodology that uses a single stress tensor versus the six stress tensors that would typically be applied by the code.

Vogtle currently uses FatiguePro which was developed by EPRI. And this is a piece of software that does use a single stress tensor. It uses it for stress based fatigue monitoring which primarily would be needed when we enter the period of extended operation and we would have to apply environmentally assisted fatigue.

At this point in time we can do our fatigue management by counting cycles to the design base of cycles and evaluating what effect that has on fatigue. But basically keeping CUF below one.

Looking at what's going on in the industry, the technology that we have currently. I know that EPRI is considering upgrading FatiguePro. There's other software out there currently that does use six stress tensors. And we're looking at 18 years before we have to have it in place, or actually 16 since we made a commitment -- no it would be 18 because it will be 20 years from now, to have it in place for our period of extended operations.

Instead of trying to defend the current version of FatiguePro we've committed to implement a software that will be benchmarked using six stress tensors, or even later technology that's developed at that point. Computers are probably going to be faster and able to do more than they currently can.

But we will implement software that is endorsed by the NRC or at least meets their expectations with regards to appropriate stress tensors and bench marking.

MR. HOLIAN: Using that single compound that is no more correct today than it will be when you renew your license. How large are your margins to your current?

MR. MYER: We did some base lining and it was -- the factor I believe it was two or three times more conservative than what we were using. But we don't -- like I said at this point in time we're not using it as stress based --

MR. HOLIAN: You're just counting cycles?

MR. MYER: We're just counting cycles. We had actually moved in a couple of locations to stress based because we thought that would be appropriate. But we can use cycle counting so we're moving back to cycle counting under our current vices and approach because we're within the bounds of our current design on all of our locations.

MEMBER STETKAR: With respect to that though, I had a question because it came up during the staff audit the way that you're projecting cycles for the charging nozzles and let down. You're using kind of a creative way of counting long term operating experience and weighting it basically one-fourth of shorter term operating experience.

If I understand that's the way you're doing and then projecting, or counting up a number of sort of weighted cycles and then projecting from that.

Could you explain a little bit the rationale behind that, because I didn't understand why the specific weighting factors and what the relevance of that whole process is. I mean I understand the results that come out from it, but I'm not compelled by the numbers.

MR. MYER: Well the intent was -- and there was a lot of discussion going on at the time that we submitted our application. But the intent is to write a projection of where the fatigue will be at, in this case year 60 and we're going to be calculating that number at the end of each cycle and if it ever projects based on that algorithm to be greater than one at year 60 then we'll start taking corrective action when it projects at that point.

MEMBER STETKAR: I understand, but what I'm asking is what's the basis for that algorithm. That's what's the basis for arbitrarily saying I'm only going to count this relatively large number of cycles apparently and weight those one-fourth of -- in that algorithm, weight them one-fourth compared to this other relatively small number of cycles just by virtue of time --

MR. MYER: I think part of what you're talking about is the original operation of Plant we went through a number of cycles that we now have modified our operating methods and won't repeat. But Jon Hornbuckle could probably provide more detail.

MR. HORNBUCKLE: I'm Jon Hornbuckle, Southern Nuclear. I'm not exactly sure I understand what your question is. But if I understand correctly the various locations that we project CDF for we had to go back and back calculate a projection of what the fatigue was up to the time we had data.

And then from the time we had data on we've got a calculated CUF and then our projections more heavily rely upon the period of time since we have data.

MEMBER STETKAR: That's true, but my question was in particular, for some let down line transience your old data are weighted very, very low. In some cases they are weighted zero. you basically discount the stuff. And the question is why, you know what's the basis for that.

What's the justification for it because you have a general algorithm that says before the time you had, let me call it relevant operating experience, you generally weight that one-fourth and from whatever that, was that 1995 or I can't remember the year --

MR. HORNBUCKLE: Yes, '95 was when we started collecting data.

MEMBER STETKAR: --'95 and '98 or something like that. And you wait to post that date three-fourths except in a few cases where you take the earlier experience and just basically discount it and throw it away, it's weighted zero.

And it didn't strike me -- I'd like to understand the basis for doing it.

MR. HORNBUCKLE: I think, I can't be a 100 percent sure without spending a lot of time looking back at the data to understand. But as best I can recall the case you're talking about is the loss of let down cycles where we had maybe 20 times as many during that period of time before we had data as we've had since.

And it was basically the early years we

had to learn to how operate the Plant and we had a lot of those events and we don't have very many of them anymore. And so for as far as projecting the rate of accumulation of cycles since we have data seems like a much more reasonable means of making that projection.

And we're not throwing out the others, we're keeping them in our base events in our base of our current CUF. We're just not using them to project how much CUF we're going to accumulate in the future.

MR. MYER: Specifically, if we started experiencing more of those events -- currently we're projecting a small number because we know that operations has been changed and they aren't occurring.

If we started having more events the algorithm would immediately project more events in the future. It would take the recent events and project those as being probable in the future.

So, unless we change our current performance the projection really is consistent with what we'd expect in the future. Whereas if it does change, because we're using the heavy weighting on recent events it would dramatically change our projection plan.

MEMBER STETKAR: I guess I didn't, in the things I read I didn't -- you mentioned a couple of times you changed operations performance and that might be a real forcing function for why the frequency is different.

In the things I read it more seemed to rely on the fact that you didn't really know how to categorize the previous events that -- I didn't read in anything that said that there was a fundamental way, different way of doing operations. It seemed more of a data characterization problem and you decided to characterize it as not counted.

MR. MYER: I think in the cases of loss of let down there -- while we don't have a specific change of procedures the fact that we have a lot of events early on and the events have gone away and also we've had industry experience that pointed to the fact that we needed to cut down the cycles on the let down and charging nozzles we recognized that we successfully, with recent history reduced them.

But even if you looked at the algorithm, the one you're talking about one-quarter versus a larger number or three-quarters for the recent events that's because we really do weight current events both if the number of events increases or if the number of events decreases.

MEMBER STETKAR: I understand that, except that that algorithm is applied differently --

MR. MYER: Right, I understand.

MEMBER STETKAR: -- in a few cases. And the three-quarter weighting is adjusted.

MR. MYER: It was basically that when we looked at data that just didn't meet the normal pattern we thought through it and said it doesn't make sense to apply it.

MEMBER STETKAR: You changed the algorithm?

MR. MYER: That's right.

CHAIRMAN SIEBER: But, it appeared to me though that the choices you made as to how you would distribute the data was sort of arbitrary.

MEMBER STETKAR: That's what more I was getting to is why was the algorithm changed in particular for those --

CHAIRMAN SIEBER: Yes, I understand the theory.

MR. MYER: It was basically an engineering judgement by the stress experts that were doing this.

CHAIRMAN SIEBER: As engineering judgements?

MR. MYER: That's right.

MEMBER STETKAR: Thanks.

CHAIRMAN SIEBER: You did not attempt to go back to the operating history of the Plant logs and so forth?

MR. MYER: In order to develop the existing usage yes, we've gone through all the Plant logs and when we first implemented FatiguePro Westinghouse went through all of their Plant logs and identified the number of cycles that they had gone through.

In many cases --

CHAIRMAN SIEBER: But they do have a handle on how many you had?

MR. MYER: Yes, we do. In many cases, and this also applies back to that, because we were working off of Plant logs and not actual temperatures we took a conservative view of every one that occurred prior to implementing the software.

CHAIRMAN SIEBER: The full cycle.

MR. MYER: That's right.

CHAIRMAN SIEBER: Okay.

MR. MYNAN: Just so that maybe -- when we talk about this operations procedures or how we operate the plant the fundamental difference that came out several years after we went commercial was that we as a station did not understand that when you lost let down our operating principle was to isolate charging.

That was what we would do. And what would happen is the charging nozzle of course would be hot, you lose the let down, it cools off and if you isolate the charging distance proximity to the loops it would heat back up and then you put charging back in and it cools back down and then you put let down in and it heats back up.

So you almost go through three cycles the way for one event. And so we changed our operating procedures on how we address a loss of let down to leave about five to ten gallon minutes of charging above seal injection that we can handle with our excess let down that keeps the nozzle cool so we don't go through two more cycles.

That was the predominant driver that allowed us to eliminate a lot of the cycles that we were taking on the nozzles.

MR. MYER: We have identified 39

commitments that have been made to enhance aging management at Vogtle. These commitments were entered in our Vogtle commitment tracking program.

This is a database that's fleet wide database used at all three sites and it linked action items, work orders, commitments, and we will also issue a program manual that will link all of these documents so that we have a strong basis to ensure that future owners of the programs know what their commitments are, know what actions need to be taken to make sure that we implement the programs as we enter the period of extended operation.

With that I'm going to ask that Lee Mansfield talk about the results of the Region II site inspection.

MR. MANSFIELD: Thank you, Chalmer. We had two inspections in 2008 at Plant Vogtle by the Region. One was during our refueling outage in the Spring on unit 1. One was a team inspection, a license renewal inspection in the Summer in May and June.

Out of that came two enhancements to two existing programs. One was the boric acid corrosion control program. One was the full box monitoring program. I'll talk a bit about those.

The boric acid corrosion control program specifically the inspectors, concluded that the program would adequately manage the boric acid corrosion, if any boric acid corrosion issues we might have.

However, they did notice, the inspectors noticed a non-boric acid residue in containment deposits on different components that could potentially mask boric acid leaks and boric acid corrosion.

This was principally a result of our essential cooling water system, nuclear service cooling water system having a lot of condensation in containment.

The containment temperatures typically around 100 degrees, this system runs anywhere from 65 to 80 depending on the time of year. So the temperature difference results in this uninsulated pipe quite a bit of condensation.

And the actual material that we're talking about is trolytriazole which is a corrosion inhibitor that we put in this nuclear service cooling water system. MR. BARTON: So that's the white film that they saw?

MR. MANSFIELD: Yes sir, that is the

white film sir.

MR. BARTON: That was internal. So unless that leaks in that system?

MR. MANSFIELD: That's correct, when you have leaks, you know be they small or large then this condensation which is occurring on, you know like 3,600 or so lanyard feet of pipe spreads it out. So that was the cause, you know it was small leaks and then getting distributed by this condensation.

MR. BARTON: How come you guys didn't clean it up before the NRC found it?

MR. MANSFIELD: Well, we actually have been cleaning it up. We have a program in place -- we know coming into outages where we want to go work on our clean up and repair and painting.

We also do inspections to see what's new and we re-prioritize it as we come into an outage. So right now it's an ongoing recovery process. We've done it the last several outages. In fact, I've got a picture coming up here I'll show you what we know we can do as far as recovering the piping.

I'll go ahead and tell you the corrective actions. Some implemented and some being implemented are systematic inspections that we do every outage, cleaning, repainting. And I'll tell you our inspections are at the beginning of the outage and then at the end of the outage.

MR. HOLIAN: And the leaks are from valve packing or something?

MR. MANSFIELD: Valve packing, it could be from a flange connection. It could be minor leaks over the years from our containment coolers that our service water passes through.

So, there's nothing real prevalent about what the leak is. But any time it happens it's got this material in it. It's out in the atmosphere and it turns white.

MEMBER MAYNARD: And the coolers themselves, don't they have a drain system through the --

MR. MANSFIELD: Yes sir, the coolers have a collection system that's part of our textbook monitoring for containment leakage. And but the collection system is really centered under the two bundles and not on the ends. And when we've had leaks they've been on the ends coolers.

So that collection system wasn't telling us, it doesn't tell us through the cycle that we've got, you know leakage on those coolers. We don't have any leakage on those coolers right now. We have over the years, but we've also had, you know minor leaks and packing of flanges etcetera.

We have made procedure changes to ensure that in our boric acid corrosion control program that, you know the owners and the site personnel recognize that, you know because of this configuration and the potential for leaks there could be some masking. So, we don't want them to get complacent about what this white material is. We've also done, we've also done enhanced communication with out personnel through briefings during the outage, through communications, you know electronic communications.

We've also, we are also putting in our training programs specific issues, you know specific topics about this because as we go through this recovery period we want to make sure no one ignores any of these locations.

On our boric acid corrosion control program now that really wasn't necessarily focused on this before is clearly looking at all of those issues when their looking for boric acid leaks only to make sure that we don't confuse two and ignore the wrong one.

This first photo is just an example of what this white material looks like. You know boric acid is white and crystally. And at a distance this staining looks like it could possibly be the second. And you see some corrosion there on the bulking materials.

MEMBER STETKAR: Back up, what are we looking at. I recognize the pipe but, it looks like we're looking at the bottom side of some concrete. It's an eye beam, it's hard to figure out how leakage from pipes get under the bottom side of an eye beam.

MR. MANSFIELD: Well are we looking down or are we looking up?

MR. MYER: It drips down and hangs there and then evaporates and then you leave the deposit.

MEMBER STETKAR: So the leaking pipe is somewhere out of site above the eye beam?

MR. MANSFIELD: Yes, I mean there's -- as I said there's a tremendous amount of this pipe and this piping goes through a lot of components and containment.

The next picture is just an example though of how we're -- where the process of recovery area is. We attacked the most prevalent issues and the ones most likely to mask boric acid corrosion. And we clean, we repaint, we replace materials as we need to.

CHAIRMAN SIEBER: What you are doing is cleaning up and painting things, but the leaks are still there. And what are you doing to fix the leaks?

MR. MANSFIELD: Well I tell you, there's two things. We're evaluating, insulating all of that piping which is a big job and a big deal. But we have that in --

CHAIRMAN SIEBER: What will that do, mask the leaking?

MR. BARTON: Collect the leakage in the insulation?

CHAIRMAN SIEBER: Right.

MR. MANSFIELD: Just to keep the condensation from occurring on the piping. Not to stop the leakage out of the system. All right, the leakage out of the system is you know part of our normal inspection and maintenance.

MEMBER MAYNARD: Minimizes the spread of --

MR. MANSFIELD: That's exactly right.

MEMBER MAYNARD: -- but it doesn't

eliminate it.

CHAIRMAN SIEBER: Well, the basic problem is this leak, okay. And the problem that appears on the surface is you've got a lot of residue, okay.

So you're cleaning up the residue, but what I want to know about is how you're fixing the basic problem?

MR. MANSFIELD: The -- you want to add to this Tom?

MR. MYNAN: Yes, the biggest issue that we have with this particular system is the dissimilar metals that we have on the coolers themselves. The header joints are made of stainless steel while the tubing is made out of cooper.

And the braising of the tubes to the distribution header, the braising is coming loose. Now the tubes are flared inside the header. So as long as the system remains pressurized the flair kind of seals it off and the leaks appear to go away.

The problem is when we get to outages or what not if we shut the train down and the internal pressure reduces inside these coolers they have a tendency to leak when we start the system back up.

We have a long range plan for replacement of all of these coolers with an alternative type to get rid of the dissimilar metal welds. It is a tremendous job in that we have eight containment coolers and two aux coolers and I think on each containment cooler we have 16 sub-coolers.

So, in the interim, as we kind of rank the level of leakage of the coolers from unacceptable to we can tolerate and replacing them with the existing designs if we have spares. And in the long range plan we intend to go replace these coolers with an alternative type to eliminate the issue.

So, but it's a dissimilar weld issue. They are on the ends. They are not in the collection tank. And, you know this particular issue is a lot more prevalent if you look at the joints up on the tubes themselves. So that's my understanding of where we're at.

The reason I know about this is that when this came up in the Spring my organization took this very seriously and I personally went in and looked at all of the issues inside unit 1 and make sure I understood the magnitude of the issue.

And then during and after the outage I

got with our engineering director Todd Youngblood and with Lee and said what are the different issues here, what are we looking at, what do we do going forward and you know we came up with a pretty aggressive plan to clean up, insulate, and then integrate into the plan the replacement of these coolers over the long range life of the plan.

MR. BARTON: Notice of violation always got my attention too.

MR. MYNAN: You know its, you know when I went in and looked at it, I mean I go into containment every outage. I've looked at it a thousand times and it just didn't strike me as an issue and it's because you live it day in and day out.

When you have an external person come in and point it out it's like hey, and ask that question and a light bulb goes on. You know it took us all back and said whoa, you know we need to go after this.

And I did go in and inspect level two in the Fall outage. So I understand the issue and I assure you that we've got money and plans in place to address this issue.

MEMBER MAYNARD: I understand the issue

around the cooler itself. But if you were considering insulating a lot of pipe, which to me indicates that you also must be having some leakage, I won't call it significant, but you must have leakage in other locations.

And if were just right at the cooler it looks like you would be able to isolate that in ways easier than insulating all of your piping area.

MR. MANSFIELD: I mean we do have and have had leaks on valves, packing leaks, gwinet leaks, etcetera on that essential cooling water system that is away from the cooler. So the answer to your question is yes.

And it's not that there is a particular problem there, it's such a big system with so many components and is in so much of containment that when there is a leak in these coolers as Tom said, there's so many of them and they are spread all over and there's leakage from a cooler and then you know it can be spread a lot of different ways on the way down.

CHAIRMAN SIEBER: Do you think insulating pipes will mask the leakage so that you have nice clean looking insulation going on underneath?

MR. MYER: This is stainless steel pipe. And so we wouldn't be masking going on inside. And in fact the purpose of the insulation as I said, stops the condensation so that there is no spread.

If we have leaking valves and other leaking components that's picked up as part of the normal inspections of the system.

MR. MYNAN: The piping that we have the biggest problem with -- which our contractors like, is we actually pipe in chill water into our containment during the fueling outages and basically air conditioned containment.

And it goes to one specific cooler and it's at the highest elevation in containment and -- but it's also the largest. And that particular piping is the one that sweats the most and it's during the refueling outage.

And it looks really bad because of the measures we've got to take to try to collect all the condensation that drips down to the lower levels of containment and the spread of contamination.

So, that's the one we want to go after first, although we do see issues I would see when it's hot out and it gets cold out and the containment air temperature starts to go we do see some evidence on all the other piping as well. But I don't think that's as big an issue as this chill water piping.

MR. MANSFIELD: I agree, I agree.

CHAIRMAN SIEBER: Well I lived in Augusta for a couple of years, I know it gets hot.

MEMBER STETKAR: Let me ask you one thing. I think you took an exception to visual inspection of the reactor vessel at boric acid corrosion because of stainless insulation or something like that, accessibility for high dose or something like that, is that correct.

I was curious as to what fraction or where -- you know what fraction of the service area and here that insulation was. The sense that I had it was some sort of localized area.

MR. LUNCEFORD: Wayne Lunceford, Southern Nuclear. The situation is that there's less than one percent of the head that you cannot see if you do not remove the reflective metal insulation on the top head.

And so there's about, I believe a ten man room of dose that's required to access this. Less than one percent of the head and you can see 360 degrees around every head penetration, you can.

And so the less than one percent is away from those areas where the leakage would initiate. And so that was a relaxation from the older requirements.

MEMBER STETKAR: I just wanted to -- thanks.

MR. MANSFIELD: The second issue brought up by the inspection was the water fountain in the pull box. We have -- our in scope median voltage cables at Vogtle are all in tunnels and aren't subject to getting water in them or near them with one exception and that's where this pull box came into play.

We have non-safety related 4 KV cables that run out to our high voltage switch yard for switching that supports station black out. In fact Lou, if you'll put that picture up there.

Here we go. I'm going to step up here because our pointer is not working too well.

MR. MYER: You can't do that Lee. You need to stay here where the mic is.

MR. MANSFIELD: All right.

MR. MYER: I'll point to it.

MR. MANSFIELD: There you go. What we're looking at is our high voltage switch yard is to our left looking at the picture and our low voltage switch yard is to the right. So the Plant is to the right.

We have a two feeder cables coming from unit 1 and unit 2 that come out from right to left on this picture and come out to that pull box that has the four cones on it. Then those two cables come over and feed these two 4160 to 480 volt transformers and then the power is fed out to the high voltage switch art for switching operations.

Water was found in the pull box there with the cones on it. And our corrective action for that is we now have a quarterly inspection pump out if necessary of that pull box. We also are trending the results from that and that's really to make sure that quarterly is often enough.

MR. BARTON: That program has been implemented?

MR. MANSFIELD: The program is in place now.

MR. BARTON: Thank you.

MR. MANSFIELD: Yes sir.

MEMBER STETKAR: You're still doing though just the ten year insulation check on those cables. Is that correct, no feel that there is a need to increase the frequence of the insulation?

MR. MYER: No, at this time -- this would be consistent with what other plants have found, because these are non-safe related they are in station blackout. So we implement the testing, ten year testing as part of license renewal as we prepare for licensee period.

Now there's no expectation right now that they have any problems based on industry experience. But we are -- knowing that these emergents would be questionable in the future we're going to work to keep them dry.

MEMBER MAYNARD: What's the source of the water.

MR. MANSFIELD: I'm going to ask for our support. I don't believe that we have, that we know for sure that the source of the water other than ground water leaking into the box.

We don't believe it's leaking in from the top through rain water. Would you like to add to that?

MR. MARTIN: Cary Martin with the Electrical Group. The water that's coming into those boxes is ground water. Those boxes were not designed with any kind of mastics, or you know water proofing on them.

They are just concrete boxes and ground water can seep into them. Many of them have little one by one sumps to collect the water at the bottom and let it drain away. But this one is not working and we're going to work on it.

MEMBER STETKAR: You mentioned and the inspection report also mentioned that the safety related cables are in tunnels and therefore they are not susceptible to water intrusion. There is actual operating -- you don't find any water in those tunnels at all, drains.

MEMBER MAYNARD: These particular cables -- I believe that they were providing power to the switch house to support switching when you need to recover your off site power.

MR. MANSFIELD: That's correct.

MEMBER MAYNARD: They are not instrumentation type cables that are actually providing some power. But it is not a main power cable.

CHAIRMAN SIEBER: You don't happen to have a drawing of your switch art schematic?

MR. MANSFIELD: We have it in the cable. It's 2.1 --

MR. MYER: It's really hard to see --

CHAIRMAN SIEBER: -- yes, I know. I brought this. So 2.1-17, that's even harder to see. I take it you have two off site power sources?

MR. MYER: That's correct. Cary, you want to --

CHAIRMAN SIEBER: One goes to Clark Hill Reservoir through Augusta and the other goes to South West of the Plant. Is that correct?

MR. MYER: I believe that's correct. That's -- I can't remember the name of the line now, but yes.

CHAIRMAN SIEBER: When you define the scope of station blackout, saying the scope of license renewal where on that chart do you say is in scope and -- you know I see the dividing line that is the theoretical dividing line between the high voltage and the plant type switch gear.

But I'd like to know where your restoration circuit is for station black out on that chart.

MR. MARTIN: Cary Martin again. It goes all the way out to the power circuit breakers. The 230 kV power circuit breakers.

CHAIRMAN SIEBER: Could you stand up

there and go through it because there is a bunch of --

MR. MARTIN: It's a red color and the feeder cable goes in between two 230 kV breakers and we actually included both of those breakers in the scope because there wasn't a preferred line up. So we actually have both of these are in and then this is the other source.

It comes up here and again it's between two 230 kV power circuit breakers. So we included both of those. So we actually have four breakers.

CHAIRMAN SIEBER: And so you're looking -- you're Aging Management Program for that is the passive parts of it.

MR. MARTIN: That's correct.

CHAIRMAN SIEBER: The foundations and support --

MR. MARTIN: The breakers are in scope, but they are screened back.

CHAIRMAN SIEBER: Okay, I can see why I couldn't find it on here because yours is colored. This one is not, okay. Could you, while you're relaxing back here take a pencil or something and color that in for me.

MR. MARTIN: We'll get you a larger

colored copy.

CHAIRMAN SIEBER: Even larger, okay. I would take a regular full sized.

MR. MYER: We actually will give you a copy of this drawing at the completion of this. We have one of the handouts. Anything we've shown you on this screen we're going to have you a copy of. So you'll have that one.

CHAIRMAN SIEBER: Well, you can see the source of my confusion.

MR. MYER: Yes, now I understand.

CHAIRMAN SIEBER: Okay.

MR. MYER: In summary, we had --

MR. BARTON: I have a question.

MR. MYER: Yes.

MR. BARTON: It's on the inspection report items. Your inspection report talks about a past of numerous leaks in varied fire protection piping.

Now, my question to you is what's the cause, poor insulation, unstable ground, whatever. But what are you doing to ensure that you have reliability of your underground buried fire protection piping, because the question I got after we announced the inspection report is, you know how do I know that this piping isn't going to fall apart because of poor insulation or whatever.

Whatever the root cause of all of these leaks is. I don't understand. Can you tell me, talk about that a little bit?

MR. MANSFIELD: We have a buried piping program in place right now where we used to do inspections on a number of systems including fire protection. So that's in place as we speak.

We do periodic pressure testing of the system. I don't know, and I'll ask for some help if anyone knows. I don't know if we have a root cause for the leakage other than it's carbon steel piping buried underground. I'm sorry, cast iron piping.

MR. MYER: Going back through the history of the Plant I guess initially there were probably a number of poor insulation items that came up and were fixed early on.

A lot of the art is not in the seismic backfill and so there is some amount of settling that's going to be expected as you have in about any kind of mechanical cast iron joints.

And so periodically we have some leakage of them. I know that we -- the complainant considered a number of different options to try and identify them when their small leaks. But any leaks that would start to have an impact on the system shows up through the jockey pump coming on more frequently or running continuously.

And all of those monitorings will drive them to start searching for leks. There is technology out there now and I know the Plant has used it to go out and find leaks that are not showing up above ground. And they are doing that. They are pretty aggressive in keeping the system.

MR. BARTON: Do you really monitor the fire protection planting which has a history of reflecting leaks. Do you view their program and are satisfied that they are doing an adequate program on fire protection planting. You made an issue in your reflection report of various leaks in the piping system over a long period of time. So, I don't where you guys stand on it.

MR. LAKE: My name is Louis Lake, I was the lead inspector for the NRC inspection. We looked at their Aging Management Program and their current programs in monitoring the fire protection and we find that the programs are adequate.

We actually did do a visual inspection on the inside diameter of disassembled fire protection piping to look at the condition internal in the pipe separate from the mechanical connections of the cast iron.

And the condition -- internal condition of fire protection piping at the site was, it almost looked pristine as if it was brand new. So, there -- as far as looking for leaks as a result of failed piping aside from the mechanical connections I think their program that they have identified in their Aging Management Program and their current fire protection program surveillances are adequate in identifying any problems with the fire protection system.

MR. MYNAN: I would just add, in this particular area we have a fairly, we've had a number of issues is we've had the main header that goes all the way around the perimeter of the power bar. But then we have a number of lines that tape off and go to remote locations within the owner patrolled area.

The main one, that's the long one goes out to our fire training facility which is almost a mine through the pine trees and all the way out there.

What we have observed is when we start our fire pumps, for whatever reason there's some water hammer that occurs down on that end of the piping which is where most of the leaks, in fact we just had a pretty significant one here a few months back that actually caused a big sink hole in the parking lot. But that's where we're seeing the issues when we talk about the majority of the leak issues that we have.

The reason we're kind of trying to manage our way through it a little bit more rather than just fixing a piece at a time and not fix the bigger issue is we're trying to work through the interface with a potential for new units because this line goes right across the foot print for the new operating units.

So we're trying to decide does that, do we need something separate or do we want to put something interim in to try to manage this issue and then meet the needs for potential units on Vogtle three and four, so that's my understanding of the biggest issue we have with underground piping.

MEMBER MAYNARD: Okay, do you have the ability to isolate that fire?

MR. MYNAN: Yes, we do. But when we do it we take a hit on our insurance because it also goes to our warehouse.

MEMBER MAYNARD: I understand, but I'm worried about the impact on Plant fire protection.

MR. MYNAN: Yes, we can isolate it and we don't have -- in fact, this recent one we had outside the gate we were in a 24-hour shut down until we could get the line isolated and then recover the line piping within the power block.

So, but we have several post indicator valves that we can isolate and isolate that section of the piping. But as I mentioned we don't like to leave it isolated because it's an issue of insurance.

MEMBER MAYNARD: Looks like it's important to resolve that for both the commercial and safety standpoint.

MEMBER MYNAN: Yes, yes I agree with you.

CHAIRMAN SIEBER: I have a couple of more questions to ask. One of them relates to license renewal and one is a result of curiosity.

Relating to license renewal, underneath your Plant is about a thousand foot thick lens of sand down to bedrock. What steps do you take to measure the settlement of Plant buildings individually and all together so that you don't end up with stresses and stains from piping and conduit and so forth that go from building to building?

MR. MYER: We've got a pretty extensive monitoring program. We've got about 160 points that we monitor. They've been monitoring them since day one. I believe now all but 16 of them are on a five year cycle because settlement has reduced to a level that we've got approval for five years and 16 are still on a one year cycle.

CHAIRMAN SIEBER: But you have seen settlements since the Plant was built?

MR. MYER: Yes, and as would be expected early on it was significant and it's leveled off. And like I say, most locations it's now been so quiet that we've gone onto a five year cycle.

CHAIRMAN SIEBER: You do that with surveying instruments or highway survey type instruments?

MR. MYER: I'm not sure if it's highway, but it's Georgia Power Company does it, yes.

CHAIRMAN SIEBER: Right, it's highway. I would presume that the settlements that you measure are relative to some base point in the Plant?

MR. MYER: That's right, we'll measure a

base point and then we'll use targets on buildings that are built off that one base point. And that base point, it's relative location does tend to some times bury from measurement to measurement with the overall site. But all of the readings are off the one base point.

CHAIRMAN SIEBER: That would be my concern.

MR. MYER: Right.

CHAIRMAN SIEBER: And the other concern is the frequency with which you measure because it does impact the structures.

MR. MYER: Right.

CHAIRMAN SIEBER: And you -- I'm sure you have from seismic reconstruction -- separation between buildings with the seal in between?

MR. MYER: In all the locations we have allowable -- differential settlement all redefined based on the stressing in the piping. It's been a couple of years since I looked at the data, but we really haven't had much relevant settlement.

But there were only a handful that the stresses were even to 50 percent of the allowable for the differential that we had.

CHAIRMAN SIEBER: Yes, but that's added

on to all the other stresses.

MR. MYER: Yes, that was 50 percent of what we allowed in settlement which is a small margin of the stresses we have --

CHAIRMAN SIEBER: Of the total stresses --

MR. MYER: Right.

CHAIRMAN SIEBER: -- piping can take. Now my curiosity question is, the picture the planter I take it's a submerged right behind the cooler point?

MR. MYER: That's correct.

CHAIRMAN SIEBER: And behind the -- or beyond East of the Savannah River is the Savannah River Plain with the Department of Energy?

MR. MYER: That's correct.

CHAIRMAN SIEBER: And on the horizon there I can see a white building?

MR. MYER: That is the cooling tower for the K-reactor.

CHAIRMAN SIEBER: Is that a hazard in your emergency plan?

MR. MYNAN: No, it was never placed in operation.

CHAIRMAN SIEBER: Okay.

MR. MYNAN: They spent $300 million dollars and then cancelled the production program.

CHAIRMAN SIEBER: It actually doesn't operate that way?

MR. MYNAN: No.

CHAIRMAN SIEBER: Okay, thank you, I've also been there and I thought that's what it was but I didn't know whether it was operation or not. But you're supposed to take into account hazards that are close to your Plant and or nearby on transportation. Savannah River doesn't have a lot of transportation, so --

MR. MYNAN: No, we actually meet with them every six months with their emergency response team is pretty interesting mainly because of the number of deer hunters that they have over there and how they can manage it.

But when we meet with them actually the hazardous material to have over there doesn't really pose any sort of large area release threat to our station.

Believe it or not, I know it's kind of surprising the first time they told me, it's because of all the tension on the ground, you know we actually pose a bigger threat to them which is why we meet with them.

CHAIRMAN SIEBER: Your emergency plan coordinated so that the incident that your plant you notify them?

MR. MYNAN: Yes, yes.

CHAIRMAN SIEBER: And they take action, okay.

MR. MYNAN: Like I said we drill with them at least once a year. But then we also interface with them twice a year, once at our site, and then we actually meet at their emergency response. All of the emergency directors go over and meet with them at their response center.

CHAIRMAN SIEBER: Now, Barnwell is about 35 miles to the Northeast?

MR. MYNAN: Well, yes.

CHAIRMAN SIEBER: Okay, thank you.

MR. MYER: In summary, as I shared we had a very experienced team that created a high quality license renewal application. We made extensive use of the GALL and we're very familiar with it.

We had what I would consider thorough and successful audits and inspections of the Plant. And throughout the inspections and audit I think our license and renewal team was highly responsive to the NRC and I think that was exemplified by us not having any open items or confirmatory items. And we believe that Vogtle is prepared to manage aging beyond 40 years, thank you.

MR. BARTON: I have a question.

MR. MYER: Yes.

MR. BARTON: You had a chemistry upset or something with steam generators a while back. I don't remember the details of that, but do you still have the original steam generators or have you changed them out?

MR. MANSFIELD: No, we still have the original steam generators.

MR. BARTON: So have them for another -- okay, no reason to change them as you see in the future?

MR. MANSFIELD: There may be a change out in the future, but we don't anticipate it at this point based on the degradation we're seeing on the tubes and on the structure.

MR. BARTON: All right, I just wondered with the chemistry upset whether it was some long term damage and you saw a need to replace it. Okay, thanks.

MR. HOLIAN: Do you use sink injections?

MR. MANSFIELD: We do.

MR. HOLIAN: And you've been doing that for a long time?

MR. MANSFIELD: What the last cycle of the generator, is that about --

MR. MYNAN: We did mid-cycle injection because of issues we saw with AOA if we tried to do beginning of cycle. This recent core design on Vogtle one we started zinc injections at the beginning of cycle and we started zinc injections on unit 2 as well so we could get full cycles since injection on primary side. So, these would be the first operating cycles that we've full cycle zinc injections.

MR. MACFARLANE: Just to touch on your question about steam generators. Now this is Mike MacFarlane with Southern Nuclear. And we did do a chemical cleaning on the secondary side of that generator, those generators.

And also the Vogtle has the monolyth generator which has the thoroughly treated 600 tubes and stainless steel support plates. And so it is a little bit of a generation beyond what the early generation PWR's had. So it is a --

CHAIRMAN SIEBER: Not good enough.

MR. MACFARLANE: Well I understand that, but that's why at this time it still hasn't had the problems that some of the others have had yet.

MEMBER MAYNARD: Are all the tubes thermally in yield?

MR. MACFARLANE: That's correct.

MEMBER MAYNARD: Well some of the earlier ones --

MR. MACFARLANE: They are thermally treated as opposed to mechanical yield. I mean the term for those tubes would be thermally treated.

CHAIRMAN SIEBER: Any other questions from the committee members?

(No response.)

CHAIRMAN SIEBER: If not we'll rule a bit early, but the chance are we may finish early. So, I'll like to take a break until five minutes after 3:00 p.m.

(Whereupon, off the record from 2:43 p.m. until 3:05 p.m.)

CHAIRMAN SIEBER: I'd like you all to take your seats so that we can continue our meeting. And I'd like to return to Brian to say a couple of things before we start on this fast review of the SCR. Brian?

MR. HOLIAN: Good, thank you. Just a couple of items before I turn it over to Don Ashley, the Senior PM in charge of Vogtle.

One is really I wanted to commend Donnie also as he's here as we've had Plants extend into ASOB proceedings and the like, Donnie's had not only Vogtle application but also the Oyster Creek application. So you know, a lot of work on his plate and I just wanted to highlight that to the committee.

MEMBER MAYNARD: Did he deserve all that punishment.

MR. HOLIAN: And he's coping just fine with that, how about that. The other thing I wanted to mention and I did mention the staff here and I just wanted to mention we do have a lot of technical members from the staff, both branch chiefs and technical members from the technical divisions also. I won't mention them.

But just remind them as they get up and answer questions to make sure you give your name and division for the record.

The other item I wanted to mention was, you know we did get the committee a draft, SCR and even on the licensee slides they mentioned 39 commitments and you might notice from our list in Appendix A there's 41 numbered there.

Most of you probably caught that there were two numbers missing. So really technically there's only 39 there, numbers through 41 and that's part of the tech editing that we still picked up that you didn't see, but we are finalizing and picking up those kinds of corrections. So, the commitments do match 39 and I just want to just mention that.

And finally, I did want to highlight to the committee you do have us back again tomorrow for a license renewal status update. We'll be covering just the program in general. Things like the IG report, things like the GALL update where we're going with that, license renewal guidance documents, how we're updating that for both us and the industry and also touching on schedules and what we have in house. So we look forward to that tomorrow afternoon also.

And with that I'll turn it over to Donnie Ashley.

MR. ASHLEY: Thank you sir, good afternoon, my name is Donnie Ashley. I am a Project

Manager for the Vogtle Electric Generating Plant license renewal project.

I along with other members of the staff will discuss our review of the Vogtle license renewal application as documented in the draft SER which you've been provided.

I'll begin with a brief overview of the application itself and the renewal effort followed by the scoping and straining review results. The audit inspections, the audit and inspections will be discussed next. Mr. Louis Lake who you've met already is a lead inspector for the Region II Inspection Team and he's here to discuss that inspection result. I'll then continue with the discussion of the SER audits and results of sections three and four of the SER.

The renewal application was submitted in June of 2007. As was mentioned earlier the unit 2 Vogtle only had 18 years experience and the reg's do indeed require 20. The applicant requested and was granted an exemption in January 2007 to that requirement or prior to the submittal of the application for both units.

The application was accepted in August of 2007 and had a Federal register notice published at that time. Subsequent to the receipt of the LRA the measurement uncertainty recapture that Mr. Myer spoke of earlier was granted and that changed the power level from what was shown in the application from 3565 megawatts thermal to 3625.

On the safety evaluation report the staff was aided with audit reviews and additional information provided by the applicant in response to 87 RAI items, and a 173 audit questions from the audit itself.

These audit questions make up the Q&A database which was included in the audit summary report that was provided to you.

When considering notes A through E of the AMR line items we've got approximately 87 percent of the line items as being consistent with GALL.

The information collected from the audit and RAI responses were used extensively in the development of the draft SER. And as Brian mentioned, in actuality of the 39 commandments the applicants did not use two numbers when the application was submitted.

We changed Appendix A in our working draft for the final version to show that commitment number ten and commitment number 22 were not used at Vogtle. The SER contained no open items and no confirmatory items.

MR. BARTON: I have a question, does SER section 33225 talk about hardening and loss of strength due to elastomer degradation. And there's a discussion in there and I thought I read the SER was issued, had been issued without this item being resolved and yet I only find the open line. Was this issue resolved?

MR. ASHLEY: It came up as a RAI during the audits and at the time that the draft was made that had not been finished. But subsequently, the next paragraph --

MR. BARTON: Okay, because I kept looking for an open item. This stated that this was not resolved at the time, all right. But it is resolved?

MR. ASHLEY: It is now sir.

MR. BARTON: Okay.

MR. ASHLEY: As Brian mentioned and as part of the comments that you had provided back on review of some of the staff you did see some editing remarks in the draft and those have subsequently been removed and corrected.

MR. BARTON: Thank you, that's half the one I listed comments against you guys. But, since you said you've taken care of all of that I guess I won't bore you with them later and they will remain in my report because I won't take it --

MR. ASHLEY: It just gives you room for others. The specific audit -- excuse me, I'm on the wrong slide here. In the audit and review, the audit summary report, I'm sorry was made publicly available in September of ‘08 and it includes the review results, the Q&A database, and the list of the documents that were reviewed by the team.

MR. BARTON: Did your summary report have any meat in it or was it just 62 pages of things that you reviewed, but did not get the whole report?

MR. ASHLEY: The Q&A database was the vast part of it. It's a little different than what you probably have seen in the past. It's now a summary report and I believe that Brian will probably be talking about those later on rather than a input directly to the SCR that you --

MR. BARTON: I just wanted to know value it was because all I got was 62 pages with a lit of all the documents you reviewed at the site. I don't know what value this is.

MR. MEDOFF: To address your comment, this is Jim Medoff of the staff, I'm acting brand chief for Jerry Dozer today whose the branch priest for the technical review staff. And I'm also the senior technical reviewer for Vogtle.

With respect to the audit summary report we did it a little bit of different for Vogtle because we were changing our process to the new processes so that it's commending with the Beaver Valley application.

So for Vogtle, for the audit report the decision was made to only list -- give you a list of the documents we looked at and to include the question list that we sent to the applicant and put their responses that they submitted back to us in the audit report.

And then to address the questions that we asked during the audit we wrote them up in the SCR product. So, any of the questions that you see in the database should be written up in the SCR.

MR. ASHLEY: Section 2 of the SCR discusses structures and components subject to the aging management review. It has to do specifically with scoping methodology for the license renewal application and it covers the plant level scoping results of the relevant systems and structures.

The staff found the results by the Applicant also meet the review criteria in the standard of view plan and in accordance with the agency.

In the structures and components section for 2.3 there was 98 mechanical systems, 34 of which were balance of plant systems. The staff believes that the available guidance that the applicant used in identifying such components is adequate.

There was three opponents added to the system. The non-ESF, Exhaust Fan Housing, and unit heaters were added as a missile barrier function to make up air duct for the electrical vent system has an A-2 scoping issue. And the chiller compressor components, housing filters and dryers were added to the scope as a result of RAI's.

In Section 2.4 in scoping and screening there was no emissions of structural components within the scope of license renewal. 2.5 and electrical instrumentation and control we again saw no emission of electrical and instrumentation components that we didn't scope.

I'd like to ask Mr. Lake now if he would go ahead and discussion the inspections.

MR. LAKE: My name is Louis Lake, I'm a Senior Reactor Inspector from Region II of the division of reactor safety. And I was the inspection team leader for the on-site inspections for license renewal.

MR. BARTON: I have a question, the cover letter on the inspection report stated the Plant equipment was being maintained adequately.

MR. LAKE: Yes.

MR. BARTON: My question is, and I'm not trying to be smart here. Does that mean the equipment is being maintained in accordance with your expectations or barely satisfactory?

MR. LAKE: No, it was in accordance with our expectations.

MR. BARTON: Now, the reason I ask you that is because on page two of the report they say the Plant equipment is being maintained adequately "in most of the Plant."

MR. LAKE: Yes.

MR. BARTON: What does that mean?

MR. LAKE: Well, we went on further to clarify that due to the results of previous NRC inspections inside containment that resulted in the notice of violation that the condition of the components inside containment weren't necessarily something that we could ignore and we felt we had to address.

Now, the reaction by the licensee satisfied our concerns and the corrective actions that he is taking also satisfied what our expectations were.

MR. BARTON: So it was really pertaining to the issue you found with the white stuff in the container?

MR. LAKE: That's correct.

MR. BARTON: All right, because I was wondering -- I wanted to make sure you weren't talking about, you know like out buildings or auxiliary buildings other than the main power block that you didn't find conditions there to your expectations. I just wanted to make sure that's not the issue.

MR. LAKE: That is not the issue.

MR. BARTON: Okay.

MR. LAKE: This slide is kind of left over from some previous, older presentations and it's geared towards ACR's members who may remember some scoping issues that -- or scoping that we had when we did our onsite inspections.

And basically they have been revised and our scope for the onsite inspections were reduced when it came to reviewing the components that belonged in the license renewal program.

We used to almost duplicate what NRR did in identifying components. And since then the manual chapters 2516 has been revised. It was about three or four years ago. And we now concentrate and put our focus on 10 CFR 54.482 situations which are specifically, we are non-safety related components that could effect safety the way the equipment functions.

We put our resources towards that review. And again, this may be a slide that has fulfilled it's purpose up to this point in time. I think most of the CRS members probably remember the revision in this scoping, but that was the intent of this slide.

NRC inspection manual chapter 2516, it provides the policy and the guidance for the review and inspection activities associated with license renewal inspections. And the NRC staff verifies the accuracy of the license Aging Management Program associated with the applicant's request for license renewal under 10 CFR part 54.

Now, the inspections that are referenced in the manual chapter are conducted in accordance with inspection procedure IP 71002. And it's to verify that the applicants license renewal program including the support activities are implemented consistent with the requirements of 10 CFR part 54.

This includes the guidance that requires us to prepare and submit an inspection plan. We also schedule our inspections to support the NRR review in a culmination of a draft SER.

The resources that we use consist of a team typically of five members. However, I was fortunate in having the support of seven inspectors and the reason for this is that it facilitated the training of new license renewal inspectors and also the sharing of inspections between regions.

The team included one inspection from Region I and one inspector from Region III. Also included in our team was a member of the ACR staff who not only observed our activities but also participated by conducting some of the inspections.

I'd like to thank Chris Brown for his excellent support during the inspections. The objective of these inspections are focused on the

Aging Management Programs and it's to confirm that the existing Aging Management Programs are working well and also to examine the applicants plans for establishing new Aging Management Programs and/or enhancing existing ones.

The inspection is typically two weeks in length and those two weeks are separated by a week back at the regional headquarters in Atlanta where we review what we had found up to that point in time. And also maybe revise our plans for the remaining inspections.

We review the 100 percent of the applicants Aging Management Programs. The inspection requirements and the inspection procedure requires that the sample programs, that we had enough staff and resources and time that we did all 38 management programs.

And we did that to verify that the aging effects will be managed so that there is reasonable assurance that the intended function would be maintained consistent with the current licensing basis throughout the period of extended operation.

We also interviewed personnel and we examined records. The records of past tests, surveillances, operating experiences and corrective actions from the existing Aging Management Programs.

Also, we examined implementation plans for existing programs new and expanded Aging Management Programs. We verified the inclusion of future tasks were included and established in site task commitment tracking systems.

We also verified material conditions of the plant was being adequately maintained by conducting plant walk downs, including walk downs of the containment during outages when the containment was open.

Now the containment was not open during our inspection, it was only open that -- by refueling outage prior to our inspection for unit 1 and unit 2 was after our inspection. I'll go through that discussion later.

The Aging Management Program inspection was conducted on site from May 19th to June 6, 2008. As I said before with the week in Atlanta for documentation review and analysis.

The inspection team concluded that existing programs are generally functioning well at the aging management portions of the license renewal activities were conducted as described in the application. And that there is reasonable assurance that aging effects would be properly managed throughout the period of extended operation.

In walking down Plant systems and examining Plant equipment the inspectors found no significant adverse conditions except for some degradation noted in material condition of surfaces inside containment due to general corrosion that I'll cover in more detail later. It appears plant equipment was being adequately maintained.

The applicant had established implementation plans in the action requests system to track the committed future actions for license renewal to ensure that they are completed.

We concentrated heavily on that issue because their extended period of operation is so far away you're talking about 2027, and you know this system needs to be very comprehensive and be able to track that, you know they do what they said they were going to do when the time comes.

We did not have an observation on that and recommended that they do make some enhancements in that and be clearer on what they put in their implementation program.

Region II will follow up with future inspections. Mainly in the 2026 and 2027 time frame and we'll be using inspection procedure 7003 and inspection scheduled after license application approval and just prior to the period of extended operations.

MEMBER STETKAR: In the SER you mention only, back to the cable issue again, you mention only the two year inspection requirement for the underground cable. I looked for -- since the applicant apparently made a commitment to change their inspection philosophy I looked to see how that was referenced in the SER and it isn't.

The SER talks only about ten year inspection events, you know testing of insulation and the standard two year inspection. Under the discussions of operating experience, under discussions of inspection results and things like that.

I was curious why that information didn't filter into the SER for that particular program?

MR. ROGERS: May I help with that one?

MR. LAKE: Sure.

MR. ROGERS: I'm bill Rogers, I'm in the division of license renewal in the interim review branch. And this issue is currently being looked at extensively by the staff and we really have it divided up into two areas.

The current Plant operation which is currently in the part 50 basement, also under license renewal. And it's being addressed in both areas. If the inspection team is doing inspections to find the adverse conditions that might be addressed by the region during current operation.

In addition, at headquarters the division of engineering, the electrical branch, is also issued some generic communications in this area related to water in the manhole and cable conditions in general.

One of those is generic letter 200701 which was inaccessible or underground power cable failures that disabled accident mitigation systems or caused plant transients. And that was issued on February 7, 2007. And that generic letter requested of the licensee's was to provide us information specifically to cable failures. And part of that would be due to significant moisture or submergence.

The licensee's have all responded to that generic letter, that information is being gathered, it's currently under review by a division of engineering and they are putting together a position on, I guess on our analysis and review of that.

Now, in license renewal space for part 54 the staff has addressed the water in the manhole issue and the corresponding raceways in the GALL report which is Section 1183 which relates to inaccessible cables.

And part of that section requires that if you are to use that program that you do the two testing points which one is prior to the point of extended operation and one is to follow-up ten years later during the period of extended operation.

So, the three points of 1183 requires, as I said the cable tested prior to the period of extended operation to determine functionality. And it's significant moisture determined during the required periodic inspections of the manholes.

Then the period of this inspection would be required to be increased accordingly. And the corrective actions would expect to be taken to remove the water when discovered.

So that is our staff's position on the two different periods of operation. Does that help?

MEMBER STETKAR: Partly except that the SER makes no mention of a variable inspection frequency for water accumulation as a function of operating experience. It just says the inspection team looked at the operating experience and the staff has found the two year inspection frequency to be acceptable.

MR. ROGERS: Okay, maybe I can get someone else to address that specifically.

MR. LAKE: Just to elaborate on that too --

MEMBER STETKAR: I understand the difference between current operations. But I'm looking at this document which is, you know SER --

MR. LAKE: I was going to say that --

MEMBER STETKAR: -- 19 years from now or whatever it is supposed to apply to.

MR. LAKE: -- I was going to say in our inspection report itself I think we refer to them going to a quarterly frequency. And then if conditions permit they can then go to the two year.

MEMBER STETKAR: And I guess my curiosity is why that didn't get reflected back into the SER, because as I read the SER I could have taken verbatim what they had in the license renewal application and pasted it in here and it's pretty much repeated without that additional information which I think is useful information.

MR. ASHLEY: Part of that is timing. During the issuance of the inspection report and the creation of the draft. Also, Roy Mathew --

MR. MATHEW: This is Roy Mathew from Electrical Grants. When I was in the license renewal branch I did review this program. During our audit we looked at the two cables that was in the scope of this program.

During that time frame we didn't see any water. So you didn't reflect anything in the ACR. But if you look at the AMP, Aging Management Program you see they had to maintain -- they have to inspect the manholes for a period of at least a minimum of two years and their collective action is supposed to take care of the frequency. If the applicant finds water in the manhole they have to adjust the frequency accordingly.

So the water issue was not discussed in the SER because at that time we didn't have any information or the operating experience that reviewed suggest that they had water. So, the Region subsequently they did the inspection. They found they identified the water issue.

MR. HOLIAN: This is Brian Holian, I'd

expect, other than the timing issue, that we could pick that up in the SER and make it complete story of it. So I accept that --

MEMBER STETKAR: It is truly a timing issue, although there is --

MR. HOLIAN: -- I accept that. You know, that shows that coordination I think it's known to the staff. But for completeness we'll take that comment. I agree in expanding that inspection.

MEMBER STETKAR: I find the inspection is really, really useful. But I hope that the results from those inspections and commitments based on those instructions are actually folded back into the SER.

MR. MATHEW: But, I want to make a point. Inspections are identifying issues with the, you know manholes that's being in the water. We are from the electrical branch part of part 50 activities. The licensees are expected to maintain the cable qualification to the environment that they are in.

So, part of the part 15 regulatory requirements they ask supposed to qualify those cables for that, if it is finished under subversive conditions.

MR. HOLIAN: This Brian Holian again. Billy Rogers mentioned that and the staff sometimes tries to cut it between part 50 and part 54. And I think what the committee is looking for is a, you realize that might be acceptable according to the GALL criteria, but put reality and truth into what their program is like at the site. So, you know we can expand that.

MR. LAKE: Okay, during our inspections you identified some enhancements I'd like to discuss, at least two of those enhancements and they've been discussed at length earlier by the licensee, but I'd just like to give you our inspection results as we saw them.

And specifically the AMP, the Aging Management Program for medium voltage non-safety related cables it's a new program that commits the licensee to establish a program to take periodic actions to prevent normally energized medium voltage underground cable from a manning submerged in water for a long period of time.

At this point I'd like to say that the cable that was used for these 4 kV lines, the two 4 kV lines in question was not designed for continually being submerged. We got that information from the licensee.

And there are only two underground cables in the scope of the program that run from the turbine building to the 4 kV switch yard as was presented earlier.

Those cables go through three pull boxes. I know that they showed you one, that was the one that probably had the most water in it. But, there were two others that did have water in it. And we identified those and these tables are needed as they stated for recovery from loss of off site power.

And originally the applicant had established a once every four year preventative maintenance task of pumping any existing water from electrical cables outdoor pull boxes. I know that, you know we identified that this four year frequency, when it came to the Aging Management Program was revised to two years. And Plant records show that cable pull boxes at this Plant are often found with various amounts of water. That the three that contained the 4 kV cables in the scope of the licensee renewal program were just pumped in June of 2007 and again during our inspection in 2008.

And Plant records reflect a history of

repeated attempts at establishing different measures to prevent pull boxes from flooding or to periodically remove water.

The applicant enhanced their program and the Aging Management Program to initially inspect the pull boxes as we stated before on a quarterly basis. And to consider modifications to prevent continual unacceptable flooding.

MEMBER STETKAR: In your inspection report I thought it mentioned that you though, or at least there was some indication that it was actually rain water initiated because the covers on the pull boxes weren't water tight.

MR. LAKE: And they aren't.

MEMBER STETKAR: But you didn't say it was groundwater related. There are different implications there.

MR. LAKE: There are, and their pull boxes, the covers to those pull boxes are not sealed, they are not water tight. However, I think the way they are designed, the amount of rain water that can get in will be minimal.

But it doesn't totally exclude it. And I think that was the intent of making that statement in the inspection report.

MEMBER RAY: Well wait a minute. If it is groundwater what's the relevance of how often they pump it out. Let's suppose you pump it out once a month and it fills it back up the next day until whatever the groundwater level is.

What's -- there's nothing to answer the question how long the cables are sitting in water here. Just because you pump it out once a month, once a year, once every two years, once -- what difference does it make?

MEMBER BROWN: It seems to me in fact that the cables should be qualified for immersion because it is frequently found immersed in water.

MEMBER RAY: Yes, it may be immersed six hours after you pump it out. What --

MEMBER BONACA: And furthermore, I mean even if we recognize this as a part of a license renewal program the question I have is will you do something about it now in this current 20 years of operation. I mean that's the best practice I would expect, you know if the program is unacceptable as is, when you go to license renewal you've found that it probably is unacceptable now.

MR. LAKE: We asked that question during our inspection and they have -- yes Chalmer?

MR. MYER: I need to interject because Cary in using the term -- this is Chalmer Myer and Cary Martin had used in the term groundwater was really referring to water that goes into the ground from rain.

The groundwater level at Vogtle is not that high. So this is not normal groundwater that we're not going to have the pull box refilling everyday from groundwater. But his terminology was getting to the top when you have a heavy rain just the ground itself is soaked, it's going to come into the pull box.

MEMBER BROWN: Did you inspect it everyday for months to make sure that's the circumstance, you just saying the groundwater is not -- you know it's below the bottom of the pull boxes

MR. MYER: We do know the groundwater -- I don't have the water level at the site. But we do know it's well below that level, yes.

MEMBER BONACA: We have been told in previous meetings on the same issue that the concern here is the wetting and drying. Okay, and the frequency of wetting and drying which means your challenge is the cable because of this condition.

Okay, not necessarily purely water

immersion. And here you have the condition where you are likely to have the sequence of the wetting and drying the cable.

MR. LAKE: Perhaps my presentation might lead you to believe that they always find these cables emerged. What we intended to present was that the pull boxes have water in them, not necessarily submerging the cables every time it's inspected.

However, it was -- one of the pull boxes, the one that they put up in the picture when we did the inspections, the cables were submerged.

As far as we could tell that was the only time in looking at previous results of their inspections that the cables actually were submerged.

But, as part of that corrective action what they are doing is more frequently looking at the pull boxes for evidence of water. The cables that were in the pull boxes where they weren't submerged looked, from a visual inspection because we were able to look at them, as being in good condition. It didn't seem like they were constantly being wetted and dried and wetted and dried.

However, the fact that there was some water in the pull boxes did require them to take some action.

CHAIRMAN SIEBER: Well with the number of times that this has come up, now I think we're dealing with a generic issue as much as we are a Vogtle issue. I also think we're dealing with a current operation issue as much if not more so than license renewal.

I think the staff is working on this, but my concern is, most of what I keep hearing relative to inspections and things don't really address how often in the wetting and drying of the cable and stuff. If we look once a month we really don't know what happened in the meantime there.

I think part of the staffs pursuit in a -- first of all we need to determine what is the safety significance of this. And then the other is what programs are really needed in the collective and then taking care of it because I haven't heard anything that convinces me from any of the Plants that the inspection period -- you know how do we get to that and assure ourselves that that inspection period is adequate. I haven't heard anything yet, so I'll -- I do have as much of a generic issue as anything.

MR. HOLIAN: It is, this is Brian Holian

again in license renewal. I'm aware of a couple of items. This has come up at previous meetings here. George Wilson, the branch chief for electrical is not here. But Sheila Raz is back, but two things, I know that we're working a draft generic letter on this. I know they've got NEI's attention. So we are looking at it as a part 50 issue. Go ahead.

MR. MATHEW: Okay, we are going to issue generic letter, response summary report. That will be issued within a week or so. That will capture some of the recommendations the staff has.

Based on the research we found there are 286 failures and these failures have been increased, the 20th going up. So, the staff is planning to issue a regulatory guide that stipulates the attributes for a condition monitoring program for cables.

So, this will address -- right now there are no guidance in the industry to provide what consists of a good cable monitoring program. So that's one recommendation that we have.

The second recommendation that we have, we are planning to revise the technical oversight process procedures to provide additional guidance to the inspectors with respect to inspecting their manholes, how they deal with -- if they found water in the manholes and the cable qualifications.

The third thing we are trying to do is we are going to advise the region staff to continue issuing enforcement, part of the part 50 regulations. Interesting regulations occurs, licensees to maintain their qualifications to cables.

So, there are regulations that are occurred to be followed under the current licensing term. So these are some of the recommendations and you will be seeing the report most likely within a week.

MEMBER RYAN: One of the things that I think is important is to maybe think of this from a geo-sciences perspective as well as the engineering perspective.

We've used a lot of terms like groundwater rain water, infiltration, saturated zone, aquifer and all of that. And all of those are in different places in Vogtle I'm sure.

So, I think it's important for the staff to work with the licensees that have these issues and really come to a dictionary that you can all agree on as this is what we are describing when we say x, whatever x might be like groundwater.

I know a little bit about the groundwater in that part of the country from being in South Carolina at Ten Nuclear for about almost 15 years.

A one inch rain, a five inch rain, and a ten inch rain, and a 17 inch rain which I monitored once all have different impacts on these kind of near surface systems and containments.

So, a single rain event doesn't trigger it. A half inch rain event may not be important. But a three inch rain event may be important, or a cumulative rain event over a month of some number versus some other number. Those kind of things I think you need to think carefully about because just going out and saying monthly and doing an inspection may be meaningless to really understanding trends, because the trend is not based on the calendar. The trend is based on water falling out of the sky.

So, I think, I just offer you that insight that some of the geo-sciences folks that may be in the other branches or, you know you can call on, I would say particularly the low-level waste branch there with a few folks that might be helpful to give this problem a little shape so that the licensees can say, oh if we do these types of things we can really, you know understand what's physically happening in the system.

And I guess I leave you with that thought. What you really want to find here is what's the system you're trying to understand the behavior of. And it's a little bit more complicated than just a monthly inspections of is there water in the sump or not.

MR. MATHEW: Actually what we had planned to do is the engineering staff is working with the research staff to come up with the regulatory guidance. We expect to issue this by the end of the next year, that's the plan.

We have obtained the necessary feedback on the guidance we're going to issue. Again, the concern the staff has if a cable is submerged and if the cable is not qualified for that environment the cable can deteriorate with an inadequate monitoring program you cannot tell how the cable is going to perform.

MEMBER RYAN: And again, that's kind of the engineering side of if it's wet is that a safety significant issue and how much and what were the issues there. I'm kind of accepting that part of something that's of interest to the staff.

And then how do you get measurables or indicators that really tell you we've got a huge problem, a little problem or a episodic issue that we can deal with in some simple way. That's really when you get to define how the system is behaving and it's not just the matter of annual rain fall. It's even driven.

Whether or not a basin fills up is based on has it been dry for six months and now we have three inches of rain or we had three inches of rain every month for the last six months. That's a big difference in how these sumps are going to respond in terms of filling or not filling.

So, I just offer that insight to maybe give you some things to think about as you begin to study the problem and come up with measurable that will be meaningful to the staff and understandable for the licensee.

MEMBER RAY: The pull boxes isn't necessarily the only point that water can accumulate the conduits between the pull boxes fill up with water and you never see it in the pull boxes.

In the case of Vogtle do we know if these are normal energized --

MEMBER STETKAR: Yes, they are because the screening criteria requires them to only look -- in scope has to be energized greater than 25 percent of the time.

MR. MATHEW: But, actually for license renewal purpose the scope of cables are really limited. In case of Vogtle not only two cables in the scope of license renewal.

MEMBER RAY: And I understood that part, but I just wondered if these are normally energized?

MR. MATHEW: Yes, these are normally energized because these are the power supply to all the control circuits, or you know the model upright disconnectors and 480 volt control panels in the search yard. So they are all energized all the time.

MEMBER RAY: So, it's better in that they normally energized than that they are not energized obviously?

MR. MATHEW: Right.

CHAIRMAN SIEBER: I'm confident this will be resolved by 2027 when they --

MR. HOLIAN: Well you're a confident guy are you.

MEMBER STETKAR: For my own information,

I haven't seen the -- I haven't read the generic letter I listed here. When you asked the licensees for their experience you mentioned 200 some odd number of cable failures.

What was the scope of information that you were asking for. Was it safety related cables, was it cables that are normally energy, you know --

MR. MATHEW: We asked the licensees to provide information of the power cables where all tech categories, you know, AC, DC, all outages. Within the scope of maintenance rule. That was the criteria that we used.

So, if a cable is occurred to me a safety function or some function part of the maintenance rule then they have to look at those cables. So, it went beyond the safety letters.

MEMBER STETKAR: Okay, thanks.

MEMBER BROWN: This is they are separated by being underground and buried or over head --

MR. MATHEW: No, these are all underground, all buried, right.

MR. LAKE: The next item that I wanted to discuss was what was again was discussed by the licensee previously and that is conditions in site containment.

I can start out with the boric acid program. In doing so I'd like to pass these two photos around. There's a photo and a angle globe valve showing what that white residue looks like on a component. And the second photo really is a gate valve where you do you have boric acid leaking, however minor you have it leaking from the packing and that's to represent how you could easily mistaken boric acid in this residue.

Now during the past unit 1 refueling outage which occurred before our inspection NRC walked down the containment, identified a white crystalline coating in significant portions of the containment.

This condition was also identified on unit 2 during a recent NRC inspection, but that was conducted subsequent to our license renewal inspection.

The coating was found on an emergency core cooling accumulators. The coating was also on the containment decking, on valves, piping supports, bolting, electrical boxes. It was on pretty much anything you could see in the containment and these photos are to represent the conditions that we saw is typical in both containments.

The white residue is similar to boric acid residue in that it diminishes the ability to detect boric acid leaking as previously described and discussed at some length by the licensee.

But, also what we'd like to discuss is we identified general corrosion caused by large amounts of condensation from chiller leaks. Chill water piping as discussed previously during outages sweat quiet a lot and do cause a lot of corrosion in containment. And the corrosion can be seen on structural steel, grading, on valves, bare piping, piping supports, bolting, electrical cable, junks and boxes as represented by the photos that I'm passing around.

Now, as a result of the white residue and it's interference with our boric acid inspections there was a, what's termed a green non-sited violation for inadequate procedures in the boric acid program. That was issued and it was incorporated into our inspection report for that outage.

Now, this type of violation is very low safety significance and mainly we determine that because they do do chemical sampling on the white residue to determine it's not boric acid and we haven't identified any real corrosion as a result of the white residue.

Also, they have long term improvement plan as mentioned previously. They have assigned a manager to a project. They are creating the repetitive task to identify corrosion issues in the containment. They are issuing the communications to the Plant on the issue.

They gradually are performing corrective maintenance on the areas of the corrosion as presented earlier. And they are going to determine techniques to remove the film if they can.

I know that they are looking into that. They don't want to go ahead and just abrasively remove this film because you could do more damage trying to remove the film than not. And I -- we determine that trying to remove the film does require a lot of evaluation to determine the right way to do it.

And they are also developing designs to insulate the piping that's causing all the condensation during outages and prevent sweating of that piping.

CHAIRMAN SIEBER: The coating that was

found, I think according to the applicant was due to an additive that they are adding to the cooling water?

MR. LAKE: That's correct, the chiller system has a chemical additive and apparently when that does leak and evaporates it leaves this white crystalline coating.

CHAIRMAN SIEBER: I should perhaps --

MR. LAKE: That's not easily removed unfortunately.

CHAIRMAN SIEBER: Yes, I should have probably asked the applicant this question. But is there some other chemical additive you can use to accomplish the same purpose that doesn't leave the film?

MR. LAKE: I've seen other chemicals used at other Plants, but I think we'll ask if the applicant has considered other chemicals.

MR. MYER: I think first of all this treatment is highly successful in doing what it's supposed to do and the residue in the containment as Louis pointed out --

CHAIRMAN SIEBER: Do two things successfully.

MR. MYER: But it also is -- it has not,

it doesn't have a corrosive effect in the containment. It does have the problem of appearing to be boric acid which actually based on our corrective action just makes more work for us to address it as if it is boric acid instead of treating it as if it's not.

But, I don't know that we're prepared right now to make a commitment to look at other chemicals because this primary function is a system, as an inhibitor is there are a lot of chemicals you might use that may not be as effective as that.

CHAIRMAN SIEBER: Yes, on the other hand if it's causing you the problem you may want to just think about that and maybe do something about it.

MEMBER MAYNARD: Is the corrosion that we're seeing being caused by this or just because water is getting --

MR. MYER: The pictures you've got with corrosion in other areas is primarily the condensation because there is a tremendous amount of condensation --

MEMBER MAYNARD: Well changing chemical wouldn't really change that.

MR. MYER: That's correct.

CHAIRMAN SIEBER: Well, that brings up

the other question. In your inspection report on paragraph eight you talk about coatings, you know like protective coatings like paint and so forth.

What is the current condition of protective coatings in containment and then outside of containment. I mean are they postured where chemical attack can have raw metal to work on?

MR. LAKE: I -- going by the inspection report of a inspectors that --

CHAIRMAN SIEBER: It doesn't really say.

MR. LAKE: Yes, going by the inspection report of inspectors that did the walk down during the refueling outages the corrosion that you're seeing in those pictures are representative of what they saw.

They did not see a lot of peeling, they did not see a lot of coating, degradation aside from the corrosion you're looking at.

CHAIRMAN SIEBER: Okay.

MR. BARTON: The question is one picture nuke services close cooling water valve. It looks like the packing gland is completely corroded and won't move.

MR. LAKE: I'm sorry?

MR. BARTON: Am I looking at a

completely corroded packing gland and packing nuts that looks like it was corroded and were never moved. What am I looking at here?

CHAIRMAN SIEBER: That's not boric acid. The other one is boric acid.

MR. BARTON: No, I know but I'm looking at the condition of the pack plant because the material condition -- I don't get you. That to me looks like it's a completely corroded packing liner.

And the other valve has got a chain on running through the yoke of the valve. What's the chain there for. Is that normal Plant practice to run a chain through the yoke of the valve, or I don't get it. I have problems with both of those pictures.

MR. LAKE: I don't have an answer as to what the common practice is for that chain going through the yoke.

MR. BARTON: But what about the packing liner. That's a material condition issue in my mind.

MR. LAKE: I don't specifically know --

MR. BARTON: I don't even see the threads on the -- am I looking at the threads to adjust the packing liner, but there's no threads left. What am I looking at. I'm just wondering how good you painted material condition of the Plant and then you hand out pictures like this for us to look at which are terrible.

MR. LAKE: Well, again, that particular valve is being corroded as a result of the condensation --

MR. BARTON: I don't care what's causing it. I'm just looking at material conditions of the valve. But can I adjust the backing on this valve and I would say hell no. But yet you don't make issues of -- I don't know.

I just don't know what you're coming from material condition I think that's not a good material condition issue. I don't know how many more there are in the Plant like that that you guys found or didn't find. So I don't really know what to think about your inspection report now.

CHAIRMAN SIEBER: I guess that in every Plant that I have been a number of them and I don't recall seeing in these Plants that I've been in this coating from the additive.

MR. LAKE: That was the first time I came across it as well.

MEMBER STETKAR: Just out of curiosity,

and I'll ask the licensee, I've heard several things here with additives and some people talk about chilled water systems with condensation on the chilled water piping and additives to chilled water systems. Other people have talked about leaks on nuclear service cooling water connections to large numbers of coolers in the containment with condensations on piping.

What system, is it chilled water or is it nuclear service cooling water has the additive and where is the additive coming from. Is it the chilled water system or is it the nuclear service cooling water system.

MR. MYNAN: This is Tom Mynan, what we do during normal Plant operations we supply containment with nuclear service cooling water where we shut down for refueling outage we have one aux cooler that normally gets nuclear service cooling water that we isolate and we flange in this spool pieces chilled water to that cooler and during outage operation that cooler gets chilled water.

And there is a flushing procedure and other things that we go through so as to not to mix the different chemicals between the two close loop systems. NCOW uses trolytriazole and the chill water uses the nitrite treatment. Does that answer your question?

MEMBER STETKAR: I think so.

MR. MYNAN: It's the same pipe but it serves two purposes online and offline.

MR. HOLIAN: This is Brian Holian again, maybe we could get the committee some more information on you know vice one inspection report, that kind of accumulation. You'll be getting a few slides here in a minute about plan indicators. I just looked ahead you see a lot of green indicators on this Plant.

So there are other inspection reports I think that would tend towards looking for some of the aspects of performance that might show up if you had inoperable valves or maybe a performance indicator that might turn white. It doesn't look like it's at that, but we could probably get the committee some more information on an assessment of reports including, you know maintenance inspection reports.

CHAIRMAN SIEBER: Well, I guess I can conclude something from all of this. From what we've seen and what we've read it looks like there's a problem that exists including the attitude that's used.

And it has an effect on the material condition of the Plant. The Plant is only 20 years old. We're asking -- or the applicant is asking for permission to run the Plant for twice as long as it's already run and so if you don't have a good corrective action and stop this, you know there's -- some place along the line there's going to be serious problems.

And I think if the Aging Management Program in order to correct this condition to me does not seem aggressive enough to solve the problem. And I think that that should result in additional attention by the staff.

MR. LAKE: The staff -- I'm sorry, sorry to interrupt. No, the Region II staff is monitoring all the follow-up that their conducting for this project that they started. We know that there is some short-term things that they are doing such as attacking the various areas in containment to improve the material condition.

But even in doing long term fixes as well as trying to insulate the lines that are causing all the condensation and containments. And we do monitor that. We monitor that by the resident inspectors and we also monitor that every time we go out during refueling outages to do walk downs up at containment and other areas of the Plant.

So, we are monitoring and following their progress along these corrective actions.

CHAIRMAN SIEBER: Well, the hopeful thing would be that there is progress. But right now it seems like the corrective actions are not adequate to reverse the direction or the trend that we apparently see.

And like I say the Plant is 20 years old. The average between the two plants and their asking to run it an additional 40 years and a lot can happen in that amount of time. And if we say what their doing now is adequate and it continues in the vein that it's progressing at this moment then I think that there's a problem someplace ahead due to corrosion.

MR. BARTON: Also, I'm sure inspectors go into containment each time there's a refueling outage and do an inspection in containment or walkthrough, right?

MR. LAKE: They do.

MR. BARTON: All right, now this stuff that you found and made a big deal of in this inspection report somewhere I read that this has been since the Plant started operating.

Now, why wasn't this a big deal before your inspection report because I think some damage has been done to Plant equipment in there as a result of this and this has been a long standing issue at this site.

Your inspection report even says that inspectors noted or something that this has been like this since the initial operation.

MR. LAKE: And as I stated before we do interview personnel during these inspections and in interviewing those personnel they indicated that there has been a long standing condition that they have gotten used to seeing. And I think Mike had also presented that.

MR. BARTON: Well, that hasn't done a job either because they should have notified -- I mean they should have made an issue of this thing long before it got this bad.

So, I just question what's really going on there, how adequate is the inspection program going and you know if there are issues like this in the plant. I mean this is a material -- I think is a serious material condition issue. So, I question the adequacy of the inspection program and why you guys were even looking out when you've been containment each refueling outage.

CHAIRMAN SIEBER: Any other comments on Plant area review one?

MR. HOLIAN: This is Brian Holian, you know we will take that comment and work with the region, but also with the division for monitoring the rack oversight process. And you know look at whether I know on an annual basis they'll re-baseline.

And I don't know if ACRS gets briefed on that for are we spending inspection resources in areas that aren't having benefits. And we can report back to the committee on whether they have looked at general corrosion aspects and are we doing enough on regular routine inspections.

MR. LAKE: The next share is a slides where we represent the current performance in ERO space and as it's presented in our performance grading. And as you can see all of the areas for the cornerstones of the ROP are all in green which indicate that the licensee is performing in accordance with the requirements.

And that they in their performance

matrix they would stay in what's known as the licensee's action column as opposed to additional columns. If performance is unacceptable they would go into various columns where they would get greater attention by the NRC.

I don't know if you want me to go through the details of the current performance indicators. But, the fact that they are all green right now and they are performing -- well the grey ones mean that that's no --

MR. BARTON: There's no findings except there's two green findings. That's what they are telling you.

MR. LAKE: But they're still -- I didn't realize that when it was put up there.

MR. PELTON: This is Dave Pelton, the brace chief under license renewal. Under the reactive oversight program which you are probably all well aware the performance indicators that are green by definition meet the NRC's requirements.

However, findings that are green indicate that they do not meet NRC expectations and so let's just keep that in mind as you --

CHAIRMAN SIEBER: Green means there is a finding. Grey means there isn't one?

MR. PELTON: That's correct.

CHAIRMAN SIEBER: Okay, and so you've got two findings both of which were low safety --

MR. LAKE: Very low safety, that's correct.

CHAIRMAN SIEBER: One in barrier integrity and the other one in mitigating systems?

MEMBER BROWN: And what's the nature of the finding?

MR. LAKE: I'm sorry?

MEMBER BROWN: What is the nature of the findings?

MR. LAKE: The findings that were green consisted of one violation of 10 CFR 50 Appendix B criteria. And 11 for failure to establish adequate test control measures for text spec surveillance.

There was another one in the capability of the aux sea water system to meet the design and licensing requirements. That was also a green finding.

There was a NCV, a non-site evaluation for, as we stated the boric acid -- identification of the boric acid. On unit 2 -- that was on unit one. On unit 2 there was one NCV, non-site evaluation for failure of adequate control, transient combustibles.

There was another NCV for violation again of Appendix B criteria 10 for failure to establish adequate testing control measures similar to the one that they found on unit 1 was common.

Capability of aux water system to meet design. Again, that was also identified on unit 2. There was a safety shut down practice not consistent with the analysis that was identified as a NCV, non-site evaluation.

Then there was one more non-site evaluation that had to do with emergency lights not installed as required in a fire protection program. Any other questions?

(No response.)

CHAIRMAN SIEBER: Thank you, thank you very much. Appreciate it.

MR. ASHLEY: Section three of the SER, Section 3.01 talks about the format of the application and then the staff review process in Section 3.0.2.

Section 3.0.3 has to do with Aging Management Programs. Mr. Myer talked about the numbers of programs that they had that were Plant specific as well as the new programs in those that are associated with -- that are consistent with GALL.

MEMBER BONACA: Going back to the slide from before. You told us that there was going to be seven percent consistency with GALL.

MR. ASHLEY: That's when you look at the individual line items. These are the programs that contain the line items.

MEMBER BONACA: Okay.

MR. ASHLEY: So we didn't look at it consistent from a program aspect. We drilled down to look at the line items.

MEMBER BONACA: So if you have a program which has exceptional enhancements do you consider it consistent with GALL. I'm trying to understand how to relate these numbers to those line items.

MR. ASHLEY: It's difficult.

MEMBER BONACA: Yes, right.

MR. ASHLEY: It's difficult to relate them to the line items themselves. You have to go in and look at each individual line item to get that consistency percentage.

MEMBER BONACA: Okay.

MR. ASHLEY: This is strictly from the program aspect. The next few slides that I'll show you has to do with our listing of the systems that were reviewed.

In all cases the reviewers, when they went through all of these systems looked at the cumulative fatigue damage, loss of materials, reduction in heat transfer, stress corrosion cracking, and quality assurance for AG management.

And Section 3.1 covered the reactor vessel and reactor coolant system. 3.2 covered the engineering safety feature systems. 3.3 was aging management auxiliary systems. And part of the additional information that you were given was specifically on 3.3.2.2 which consisted of AMR results that were consistent with GALL for which further evaluation is recommended. Those systems were reviewed and then provided to you in a separate package.

They also looked at cumulative fatigue damage, reduction of heat transfer due to fouling, cracking due to SCC, and hardening and loss of strength due to elastomer degradation. The loss of materials were also considered for each of the systems.

The steam and power conversion systems were reviewed as well. And one thing that's a little different in this particular system, the condensate system was reviewed as part of the feed water system rather than a separate system.

Aging management of containment structures and component supports in Section 3.5 was reviewed. One of the things of interest has been the in scope inaccessible concrete. And we wanted to make sure that we provided you with the specific information from this section.

The substance criteria for pH chlorides and sulfates were met in all situations and there was two tests performed in 2005 and 2007. They both did meet the acceptance criteria.

Section 3.6, aging management electrical and instrumentation and control systems. This also included the inaccessible medium voltage cables. And we had -- in the review of this section and the other section we had several RAIs that they applicant responded to that were specifically addressed for elastomers.

MR. BARTON: I have a question a second. In the -- as I review it it looks like there were four programs listed that managed aging effects, electrical, and INC system components. I can only find description and discussion on one of those programs, loosening and bolted connections.

Now, was I missing another page or something, because I only saw you discussing one of the four programs?

MR. ASHLEY: We should have covered them all. And they should be within that section.

MR. BARTON: Maybe you want to look because I saw one. I'm talking about page 3.5.18 in your SER.

MR. ASHLEY: I'll have to go back and look sir.

MR. BARTON: Okay.

MR. ASHLEY: I will verify that.

MR. BARTON: All right, thank you.

MR. ASHLEY: Before I get into Section 4 on the time limited aging analysis I'd like to ask Dave Pelton if he would address the subcommittee.

MR. PELTON: Hi, this is Dave Pelton, branch chief license renewal. I just wanted to bring a relatively, well somewhat recent issue to the attention of the committee.

Staff has been taking a look at operating experience related to the use of Boral and spent fuel pools. As you may or may not know there has been a past history not only with boral flex and degradation, but also with some blistering or swelling with boral.

What we've done and in specific with Vogtle is we took a look at, there's been fuel pools. Unit 1 fuel pool does include boral material. And their criticality analysis for that pool takes credit for the boral.

Our SER documents the Aging Management Program for that material and it does it in kind of a three part method. It looks at the water chemistry control that's applied. It also looks at corrective action program for the licensee to identify any issues and take action. And then it also requires the licensee to consider operating experience and take action as appropriate. And also you may note that commitment 37 also requires license or reinforces the need to do that.

What we're going to -- what the staff is doing is with all of these recent Palisades issue with some more blistering. We're going to look at that, not only generically, but also specific to Vogtle to make sure that the Aging Management Program that we currently -- that's currently in the SER continues to meet staff expectation given some of the more recent experience.

And then as appropriate or if necessary we have the request for additional information process we can use to ask additional questions of the licensee and make sure that we're satisfied that the program is adequate.

MR. MEDOFF: Let me just expand on that. Al Heizer is running division of component integrity, steam generator integrity and chemical engineering branch, and they are considering putting out an ISG on Boral degradation. So, that may come forth in the near future.

So, that's an additional measure that we're taking to address operating experience with Boral.

CHAIRMAN SIEBER: Do you get blistering mainly from chemistry and I presume when there's neutron gorging generating heating and gas which should be at a very low level at a spent fuel outage.

MR. MEDOFF: Emma, would you like to address that please. This is Emma Wong of the division of component integrity.

MS. WONG: Could you repeat the question. I could barely hear it.

CHAIRMAN SIEBER: Well, the question was

more of a comment. But, the major cause of blistering in Boral is water chemistry to my understanding.

But, if there is significant neutron fields you generate helium and gas that is within the matrix of the material which can collect them also cause blistering. I presume that this is all a water chemistry problem in a spent fuel pool, because the activity in the spent fuel pool should be neutron activities and should be pretty low. Is that correct?

MR. MEDOFF: Emily, is he on the money?

MS. WONG: Yes, he's correct.

MR. MEDOFF: Okay.

CHAIRMAN SIEBER: Now, I guess my other comment is that this is generic to -- this has been around for a long time. This is generic to Plants that use Boral.

So, my question is is it part of license renewal or is a generic issue that needs to be dealt with soon, but outside of license renewal process?

MR. PELTON: I think right now we're trading -- right now we're looking at it -- well there's a -- I'll let Alan Hiser talk first and then I'll kind of give you what our assessment was, at least recently.

MR. HISER: Alan Hiser from the chemical engineering branch, NRR. We're taking a look at that now because clearly there's nothing that changes magically with license renewal.

So, we're taking a look at the impacts on the current licensing periods for Plants as well. We don't have anything at this point on an assessment of that.

CHAIRMAN SIEBER: Let me ask another sort of mechanistic question. When you get the blisters do the blisters break and fall off and you lose the Boral. Does it lose it's structural integrity or does it just look bad?

MR. MEDOFF: That I can't answer.

MR. HISER: That's again something that we would take a look at. Just understand what the overall impacts are.

CHAIRMAN SIEBER: It's long term.

MR. PELTON: That's right, and as with any, you know kind of, as you said this isn't necessarily a brand new issue. But how we're looking at it and how it relates to license renewal we're just taking another look at it.

It's a somewhat emerging over the last

couple of weeks working closely with Alan's group. And we just want to make sure that we get our arms around it and fully understand it if any impact at all on Vogtle and then also generically.

So, we just wanted to make sure you folks were aware that it was something we were going to look at and may or may not come up -- well we'll probably -- we will readdress it at the full committee meeting so we can give you what we concluded.

CHAIRMAN SIEBER: Yes, well we need to decide amongst ourselves whether it's a license renewal issue or not because it impacts the kind of report that I write.

MR. MEDOFF: We've had a --

CHAIRMAN SIEBER: I think I'll wait to the full committee meeting and spend the entire night writing the report.

MR. MEDOFF: We have had other emerging issues in the past where they've put it into current operating space. A good example is when we had the nickel alloy cracking issues initially break out we put that in current operating space.

But since that time we've had some new requirements and we were able to use those requirements to update the GALL report and the GALL update.

So, when we get emerging issues like this it may very well be that we put it into current operating space. And once something gets established we'll use it to update the GALL report.

CHAIRMAN SIEBER: Thank you very much.

MR. ASHLEY: Section 4 of the SER contains the Time Limited Aging Analysis. The TLAA are Plant specific safety analysis that involved time limited assumptions defined by the current operating term.

The staff reviewed the information in the LRIA to determine whether the applicant has provided sufficient information according to 54.21 C1 and C2.

The applicant evaluated it's calculations and analysis against the six criteria specified in 54.3. The TLAA criteria involves SSC's within the scope of license renewal, considers it's aging effect. It involves time limited assumptions defined by the current operating term. It's determined to be relevant by the applicant making it safety determination.

It involves conclusions and provides the basis for conclusions related to the capability of the SSC's to perform the intended functions. And finally, are contained or incorporated by reference into the current licensing basis.

In the TLAA's that were reviewed, we'll go over each of these as we go over through this section. The reactor vessel neutron embrittlement analysis, Section 4.2 of the SER, there were five reviews performed to evaluate the consequences of the neutron embrittlement as documented in the SER.

These are neutron fluence, adjusted reference temperature, pressurized thermal shock, and pressure temperature limits, and upper shelf energy.

The staff reviewed the license information and found only a statement that the fluence calculations adhered to the guidance and the regulatory guide 1.190.

The staff felt that that was not adequate and to conclude adherence to the reg guide, or whether the values listed actually accounted for the previously approved power uprate and the applicable number of the effective full power years of the calculated fluence values.

To complete the required information for the review the staff calculated fluence values and the staff requested one reference to the calculations, two clarification for the listed fluence values as to whether they include the power uprate, and three clarification of the applicable EFP wise for the listed fluence values.

The applicants response provided the requested information and the staff concludes that the reactor neutron embrittlement analysis meet the review criteria in the standard review plan and in accordance with the rules.

The tables that we'll be looking at in the slides, the next slides are for 56.3 EFPY to account for the recent power uprate in the measurement uncertainty recovery.

While the w-cap values that are normally used are calculated for 57, this is acceptable because the 56.3 EFPY are still conservative with respect to expected values.

This graph represents the upper shelf energy decrease. The UOL use acceptance criteria is greater than 50 foot pounds. And if you'll note that Vogtle unit 1 is at 61 and unit 2 is at 56 which meets the criteria.

CHAIRMAN SIEBER: Do I understand this

chart properly where we're supposed to take column three number which is 70 and move it one case to track 12 and then up to 61?

MR. MEDOFF: That is 12 percent of the emission.

CHAIRMAN SIEBER: Got you.

MR. ASHLEY: Did you hear the 12 percent?

CHAIRMAN SIEBER: Yes.

MR. ASHLEY: Okay, on reference temperature calculations again the screening criteria is less than 270 degrees and unit 1 is at 123.3, unit 2 at 134.2 degrees.

The additional TLAs on metal fatigue analysis and the applicant discussed her cycle counting. And John Fair, did you have additional information for metal fatigue other than what's in the SER?

MR. FAIR: No, what's in the SER -- I'm sorry, no all I have is what's in the SER.

MR. ASHLEY: Were there any questions form that?

MR. ASHLEY: Section 4.4 of environmental qualification of electrical equivalent 4.5 containment pertain to pre-stress and 4.6 the containment liner plate, metal containment and penetration fatigue.

Okay, Section 4.7 consists of Plant specific TLA's. And this shows the listing there. The Section 4.7.5 on under clad cracking of reactor pressure vessel. This was amended and added in a letter of March 20th for the closure head dome flanges. The primary inlet nozzles, primary outlet nozzles, and the RPV flanges.

These are SA 508 class two forgings whose internal cladding was welded using a high temp, excuse me high heat submerged art weld process.

MR. HOLIAN: How is the -- there's sort of a reference to a WCAP report for the week before break analysis. What are the assumptions in that week before break analysis that you use. Is there -- do you do an inspection or do you have a postulated crack?

MR. MEDOFF: The issue with the leak before break analysis is on the cast materials. If you get thermal aging they --

MR. HOLIAN: I was thinking with 182.

MR. MEDOFF: 182, my understanding I that the pervious office directors has put that as an emerging issue to assess the impact of the SCC on the -- when the leak before break analysis and that's being handled by the division of component integrity. So, I think we're going to have to go back and find out where they stand on that issue.

MR. ASHLEY: Did you have a follow-up, sir?

MR. MEDOFF: The officer director put it in current operating space so we're going to have to go back to them on that matter.

MR. ASHLEY: On the basis of this review the staff determines that the requirements of 10 CFR 5429 A have been met.

Future commitments have been identified and a schedule is documented in the SCR such that there is reasonable assurance that the activities approved by the license renewal will continue to be conducted in course with the current licensing basis and changes associated with license renewal.

With that sir, it is my --

CHAIRMAN SIEBER: I see the last slide is the same three license conditions that has a memory license renewal.

MR. ASHLEY: Yes sir, those are the standard license renewals. That's the backup slide.

CHAIRMAN SIEBER: Thank you.

MR. LAKE: If I may, could I maybe provide some clarifications on the photos showing that globe valve and the extensive corrosion that's shown on the bolting and the tacking plan. And also on the gape value showing the boric acid and leakage.

Now the intent of these photos was to show that you really have a hard time distinguishing between boric acid. But more importantly, where I got these photos from this is a licensee photo. It was actually identified. I'm looking at the back of it now. It was actually identified in 2006 as part of the boric acid program walk down where they identified these problems and took corrective action.

MR. BARTON: So the two year old picture has been corrected or is it still there after two years?

MR. LAKE: Well based -- I'm not going to positively say it has been corrected except to say what that program would require. And their program these pictures require just to be put into their boric acid corrective action program and you correct these prior to them going back up in power.

So, this is from back, you know years ago. It doesn't necessarily represent what's out in the containment today on these two pictures.

Now the other pictures don't have any -- what's that?

CHAIRMAN SIEBER: It could be worse.

MR. LAKE: Oh.

CHAIRMAN SIEBER: Any other additional comments or statements from the staff?

MEMBER MAYNARD: I'm not sure -- I appreciate you bringing the pictures and showing them and I would hate to leave the impression we have where people won't bring us something. It would be nice if some of these could be put in better perspective.

MR. LAKE: That's true.

MEMBER MAYNARD: But I do appreciate you bringing the pictures and showing them to us. And I think that it's more than one inspection that ends up forming an overall basis of material condition and other things.

So I'll just pass that out. It would be nice to -- when bad pictures shown and can be put into perspective as to whether that's typical or whether that's an out liar or whatever it is.

MR. HOLIAN: We agree.

MEMBER BONACA: The question I have is are we aware of similar conditions in other Plants?

MR. LAKE: I have not read any inspection reports that identify similar conditions nor have I observed similar conditions.

MR. BARTON: Have you seen inspection reports that identified the condition you found during this outage which has been here since day one or since the Plant started operating?

MR. LAKE: The inspection reports that I have read, I've been with the NRC about three and a half years go back maybe two or three years ago. That's what I prepared in preparation for this license renewal inspection I went and read through these inspection reports.

MEMBER BONACA: I mean it was best to go back to get your position. It means some emphasis since then.

MR. PELTON: This is Dave Pelton again, you know Brian and I were just talking and you know he and I spent a lot of time up in Region I and have visited all of those sites and probably most of the sites around the country and I would not -- I don't think we characterize that as a typical condition.

We certainly appreciate the view that you know our inspection conclusions are based on a, you know a mosaic of opportunities to review and inspect identify issues. And we also appreciate the need to -- you know if we're going to bring pictures in to make sure it tells a good story and that it captures, you know what message are we trying to send.

And you know what we're going to do, you know we'll make sure that we'll bring to you when we go over the final SER is just put everything in the perspective that it was intended to be and make sure that we tell the right story because we certainly don't want to leave you the impression that, you know that we're walking away from material condition issues that don't meet expectations or NRC requirements.

But we can certainly put it in the right perspective for you and will do that.

MR. BARTON: This raises the question about the IPC inspection program and also material condition in the Plant and what the corrective action programs are. I mean you saw something like this and it just opens up.

MR. PELTON: And we appreciate that and we'll make sure we'll cover that for you.

CHAIRMAN SIEBER: Any additional questions from the members?

(No response.)

CHAIRMAN SIEBER: Well if not I'd like to ask each member a few questions and this will be complicated because it's a complicated way of doing business and the LROA review and approval process.

The first question I'd like the members to consider is do we need an interim order and just for information an interim order would tell the applicant or the staff or both if the ACRS subcommittee has identified one or more significant items not evaluated properly or corrective actions not identified or insufficient.

I think another reason for an interim letter would be deviation of the applicant or the staff from the requirements of 5054. And I think we write an interim letter this coming meeting that we would need an additional subcommittee meeting to determine that the issues that we raised in the interim letter if any are resolved.

Now, the answer to that probably one is no, we don't need an interim letter. Then we have to ask ourselves a second question and I would like each of you to address this. Do we have enough review material, and since some of it's late and came in pieces we may not have been able to assemble it all in our minds to make a final subcommittee finding and do -- if the answer to that is no, do we need another subcommittee meeting in order to be able to make such a finding and provide me with the advice that I would need in order to write a letter report appropriate for the full committee.

Now, the answer to one and two are both nay, no then I would like you to give me your comments as to the adequacy of the process in the case of Plant Vogtle and any issues that you believe should be included in the letter that the subcommittee would write and endorse and give it to the full committee for it's review and approval.

So, there's three things that I'm asking. Okay, do we need an interim letter, do we need additional time to review the material that we've gotten already since it came late and came in pieces, and lastly if you're satisfied with the material that you got the presentations today are there significant items that should be in our letter other than, you know we've reviewed all of this material and it's okay.

MEMBER MAYNARD: First of all we can't write a letter unless we have a portion of it set in the agenda for the full committee meeting.

CHAIRMAN SIEBER: Well, yes --

MEMBER MAYNARD: So it couldn't be this one.

CHAIRMAN SIEBER: But it's not going to be this meeting. It is going to be some meeting, okay when it comes up on the schedule. It will probably come up in March.

MEMBER MAYNARD: Jack, I'm just a little confused on your second item there and you stated it different. One you asked if we had enough material to draw a conclusion. The subcommittee does not have to draw a final conclusion. We will have a meeting at the full committee where we will discuss items that haven't been fully resolved or issues and stuff.

CHAIRMAN SIEBER: Well, I think that we can go to the full committee with that. But in order for me to properly present the review of this material you need to identify the items to which we don't agree.

MEMBER MAYNARD: And I'm --

CHAIRMAN SIEBER: Or, with which we disagree among ourselves.

MEMBER BONACA: You would want more material only in case the answer to the first question was yes, right?

CHAIRMAN SIEBER: I don't expect additional material. But what we got was in pieces and not timely. And so the question is, have you had an opportunity to -- prior to this meeting and the information that you gathered during this meeting to be able to draw a conclusion.

And the answer is not what is your conclusion, but yes or no. George?

MR. APOSTOLAKIS: I'll pass.

CHAIRMAN SIEBER: Okay, --

MEMBER STETKAR: I don't think we need an interim letter.

CHAIRMAN SIEBER: Okay.

MEMBER STETKAR: If I could answer that question. I've received enough information and I guess I'd like to hear other members of the committee about whether they -- whether there is any consensus about any significant items to be included. I don't want to be conclusive at this stage, yes or no. But I don't have any that I offer at this point.

CHAIRMAN SIEBER: Okay, thank you.

MR. HOLIAN: I agree, I don't think we need an interim letter. I -- the areas, you know my primary interest -- if there was enough information available than what I have to look through perhaps a little more information at the full committee presentation on specific programs would be helpful to the full committee.

But, at the moment I --

CHAIRMAN SIEBER: Could you describe -- it would help both the applicant and the staff for you to tell us what you'd like to hear more about.

MR. HOLIAN: Okay, I'd like to hear more about the cable program in particular.

CHAIRMAN SIEBER: We're going to do the members first and then I'll get to you, okay.

MR. HOLIAN: Jim sort of gave me a hint and in fact I shouldn't have stopped reading in the SER. I read the test from the SER and now I come to commitment 36 which says once the NRC has decided on a process to address this problem the licensee will do it.

Well, I guess I can't really expect the licensee to do much until you tell them what to do.

So, he's gone about as far as he can go at the moment.

So, I'm -- Commitment 36 is what?

MR. HOLIAN: This is a new commitment and it's once an onsite audit question 4.701. Once the NRC has adopted a process or accepted a process for addressing PWSCC at alloy 82 welds and all of the devaluations they'll do it.

CHAIRMAN SIEBER: Sounds good to me.

MR. HOLIAN: Sounds good to me.

MEMBER BLEY: Nothing new from me.

CHAIRMAN SIEBER: Dennis?

MR. RYAN: I just picked up on John Stetkar's comment. I think there's a more generic issue on how water gets into these piping systems whether it's ground water or rain water or both and what measurables and metrics are going to be important for the NRC to develop and to convey the licensee so they make a meaningful measurements on how the behavior of the system is progressing with time.

CHAIRMAN SIEBER: It's rain water because the manhole covers and there's no seal.

MR. RYAN: Usually.

CHAIRMAN SIEBER: Usually, you can lift

them off.

MR. RYAN: That's part of it, but the other part of it is, you know three inches of rain over a month versus three inches of rain in an hour kind of have different impacts on loading that system with water and I take the other point that was made earlier that some times it's in the pipes and not in the conduits and you know you've got to really think through the whole problem as a system. So, I think there's a bigger issue there for the staff to think about.

CHAIRMAN SIEBER: I think there's a different issue too. A lot of the people look at the cable itself and say it can stand this kind of environment for this length of time and remain qualified and forget about this place. The reason why your pull box is either to pull or to splice something.

And you have to -- the splices are made on the job and you have to pay attention to how --

MEMBER RYAN: And I think that's exactly the point. You know there's an engineering part of the problem and then there's a geo-sciences part of the problem, you have to put it all together.

MEMBER RAY: Well Jack, this is the

discussion I was eluding to and I thought we might have. You used the word qualified just then and I just wanted to point out that these are not required to be qualified.

And so part of my issue here is that I'd like us to discuss a little bit more is the function itself. I think Otto asked what's the safety function. I would echo that.

CHAIRMAN SIEBER: The control cables for breakage.

MEMBER RAY: Well I know, but the need for them to function is in the recovery from the loss of offsite power event. And I need to understand what the safety implications of that particular step are. I think I know, but I don't. This is not the place to get into that I think.

MEMBER STETKAR: I think there's a couple of things here that we have to be careful with. Specifically at Vogtle there are these two cables involved that are the offsite power recovery issue.

We've had other license renewal applicants come in where they have had similar problems with water accumulation for safety related cables that are not qualified. This is safety related equipment cables that are not qualified to be used under water.

MEMBER RAY: No it isn't, no it isn't.

MEMBER STETKAR: No, no not at Vogtle. But other license renewals. In a generic sense this covers a broad spectrum of possible types of cables, possible types of applications, and different Plant specific configurations.

For this subcommittee today we're only interested in what's the problem at Vogtle. The generic sense is the bigger picture.

CHAIRMAN SIEBER: Let's be clear about the importance of the cables if they are control cables that offer breakers.

MEMBER RAY: These are power. I understand that, that's why I asked if they were energized.

MEMBER STETKAR: No, these are 4 kV power cables.

MEMBER RAY: That's right, 480 volt.

MEMBER STETKAR: But we've had for other license renewal applications, Vogtle not withstanding --

MEMBER BROWN: The last thing we talked about, the last Plant we talked about had 4 kV power cables. But they were qualified. They said they were safe to work in stations like that.

MR. BLEY: I passed, but I had a generic issue since you brought up the generic side. Two comments, but it's not, I don't think it's a local issue, it's more general.

One is, we've heard a little bit about the issue of wetting and drying and wetting and I know there's work going on I think we need to understand what works going on and what applies.

Second, although I would have agreed with you a month ago that the reason there is a full boxes for a splice we'd see at least one with no splice in it. And maybe it's a long pull I'm not sure why it's that way. But, it's not always that there is a splice in there.

CHAIRMAN SIEBER: You need a place to pull it from. Okay, is it Otto's turn now?

MEMBER MAYNARD: It was a while ago too.

CHAIRMAN SIEBER: Yes, right you're going to have your turn.

MEMBER MAYNARD: I don't think there's a need for an interim letter and I think we have enough information to go ahead here.

I believe that the majority of the

issues that are really being discussed are generic issues and I think that they are current operating issues as opposed to license renewal. Maybe if you want to touch on it and stuff.

I do think they are important issues. I think we have to sort out as to what do we put as part of license renewal. And I really believe that this cable vaulting water and stuff I think is a current operating issue and I think it is a generic issue that none of us have our hands around as to the overall safety significance and what are the requirements and what really needs to be done.

And I certainly don't think that any of the monitoring programs that I've seen to date come anywhere close to -- if it is a safety problem I haven't seen any indication that the monitoring programs are really adequate for that right now.

But again, I think these are generic issues and I think we have to sort out as to what do we put into the license renewal review.

CHAIRMAN SIEBER: Yes, but just so they are given something about generic issues.

MEMBER MAYNARD: I think as far as for the next presentation and stuff I do think that since we walked about material conditions I think it would be good for the staff to come and write a little bit more information on the overall material condition.

CHAIRMAN SIEBER: Probably in inside containment particularly.

MEMBER RAY: Is license renewal Otto or is a current issue?

MEMBER MAYNARD: Both.

MEMBER RAY: Well, I understand, he should say yes. But I just want to hear him.

MEMBER MAYNARD: Yes, and also because it's something, either way it's something that we put on the public record that I think is kind of left hanging a little bit there that I think needs to be tied up a little better for the public record.

CHAIRMAN SIEBER: Yes?

MEMBER MAYNARD: Yes.

MEMBER BROWN: Two things, as an electrical guy I don't like cables under water. I was --

CHAIRMAN SIEBER: You were in the Navy.

MEMBER BROWN: It's been a long time.

MR. BLEY: You're not touching those.

MEMBER BROWN: You're not immersed in water. So, pertaining to -- so under water we don't worry about it. It's the ultimate heat sink result.

So, I've been surprised in two meetings now that there has been less information -- less -- I don't -- this sounds negative and I didn't mean it to. But, I would have had -- personally I would have had more curiosity as to source, that's why I asked the question visa vie your point.

You know is it just stuff oozing up and it's -- they inspect it, suck it out and nobody looks at it for two months and then they see some more, then well that to me you ought to know how facts does it come back and what are the environmental conditions. We ought to know were it's coming from wand what's going on.

CHAIRMAN SIEBER: Yes, one day I pump it up.

MEMBER BROWN: I didn't answer your other question first. Maybe you ought to have a pump there all the time. I don't like water in my basements. So the sumps pup --

CHAIRMAN SIEBER: A couple of hundred --

MEMBER BROWN: No, I don't think there's a interim letter. I agree that this is more of a generic type issue than it is a licensing issue. So, I piggy back on Otto's. I won't repeat all of those. But I'm a little surprised at the lack of curiosity, not meant to be negative, there's no spears being fired here. I mean it's just I like to know where stuff comes from.

And the material condition thing is interesting. If we had seen one of our Plants in that condition the CO would have been ripped off the ship. The plant would have been shut down and we would have gone -- now, all we did was see these pictures. So I have -- there's no context at all other than those what was done, when they were taken, where there mitigation things done and what have you.

It's just -- you don't -- and we've got 40 more years that we're predictably looking at taking care of this. Now, are there mitigating actions you can take, yes. Can you replace stuff yes, but some of those are huge structures, tanks. It's not easy to do.

So, is that a licensing issue. I don't know, I don't have enough experience to being a newbie here for five months or whatever it is to say that I'm just disturbed by the expanse of those pictures. But the context is not there and so it's hard for me to make a judgement.

So that's -- I would like to have somebody present to us a general context over a chronology of that as it gradually built the stuff.

For instance, if you looked at that valve was that -- you went back and looked at it today is it pristine and pretty. We don't know.

MR. BARTON: Well you have to wait until the next refueling outage.

MEMBER BROWN: Yes, so any way that's my comment. I don't know how the old -- I'd like some more advice form you with more experience in these commercial civilian plans than I have because I -- we wouldn't have put up with that in a Naval Plant.

We had a lot of salt water we deal with and so we try to keep them so we can see what's going on.

MEMBER BONACA: I agree with everybody for no interim letter. I don't see any need for an interim letter and I think there is enough review material as Otto pointed out to deal with this issue.

I believe that the full committee would be interested in both issues that were discussed here. The splicing and the water standing, and the deposits and containment. The effect of that presence of deposits on the model casting problem.

So, I think that we need to bring that issue. I think that there are generic -- the first one there are no cables. Its' a generic issue right now. We always find it and what we heard often times is that simply we will not rest the frequency of inspections, that will do nothing.

I mean to go from two years to six months doesn't tell me anything about what's happening in between the drying and the wetting issue, it's a fundamental issue and how do you monitor that. How do you prevent that. So, that's pretty much it.

CHAIRMAN SIEBER: I still like Mike's ideas to figure out why it's getting in there. When do you know when to pump it out, know when to inspect and when to pump it out. If you have a hot dry summer, you don't have to pump.

Okay, John?

MR. BARTON: I think Otto and Josh covered what I was going to -- I don't think you need a letter to be written.

I think somebody needs to look at the SER and try to find out if they said there were a lot of issues with the SER that would -- and as far as the another issue I have is what is the real overall condition of the Plant material conditional that I can look back through on the inspections and you know why wasn't this stuff picked up because it's in the same condition in unit 2, you know what's the effect on the corrective action program and things like this.

That's about the only issue I can come up with.

CHAIRMAN SIEBER: Okay, well thank you very much. I think that it might be a good idea to address two things from the same point of the applicant and the staff.

One of them is the water in the manhole issue. You may have some new ideas about -- after the four hours of discussion some new ideas about how you want to deal with it.

The other one is a trio condition in containment. I may have some new ideas about that and the third one would be, I think from the staff.

Let's take a look through the inspection reports to try and get a better handle on material condition so that we can make a judgement on this to whether to the Plant is to grading and we'll grade seriously by the Sergeant license renewal or not.

MR. BARTON: I understand.

CHAIRMAN SIEBER: You need to cut her an assessment for overall material conditions.

MEMBER BROWN: I understand.

CHAIRMAN SIEBER: So, in addition to giving the broad over view like you are giving here for the record then we'll have less time, we're only going to have about an hour and a half or two hours. We'd like you to touch on those three subjects and for the applicant to touch on two of those three. So, with that being done let's finishing exactly on time.

MEMBER RAY: We are and I'm not going to delay us Jack, but I wanted to make one comment and that is -- there's been all this rhetoric about material conditions. Just remember, ALARA is a issue whenever you talk about having material condition Christine you're also got to demonstrate that it was consistent with ALARA.

CHAIRMAN SIEBER: One of the things I learned working in Power Plants for 38 years was if you have a clean plant it sort of goes a long way.

MEMBER RAY: Well, inside containment is a different story.

CHAIRMAN SIEBER: Okay.

MEMBER RAY: Say one more time, ALARA is important. I didn't hear it mentioned. I think it should be mentioned.

CHAIRMAN SIEBER: Okay, with that thank you very much both Southern Nuclear and the staff. This meeting is adjourned.

(Whereupon, the meeting was adjourned at 5:02 p.m.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards

Docket Number: n/a

Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Eric Hendrixson
Official Reporter
Neal R. Gross & Co., Inc.

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United States Nuclear Regulatory Commission
Protecting People and the Environment

Advisory Committee on Reactor Safeguards (ACRS)
License Renewal Subcommittee
Vogtle Electric Generating Plant (VEGP)

Safety Evaluation Report (SER)

November 5, 2008

Donnie J. Ashley, Project Manager
Office of Nuclear Reactor Regulation

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Introduction

- Overview of VEGP license renewal review
- SER Section 2: Scoping and Screening review results
- License Renewal Audit and Inspection
- SER Section 3: Aging Management review results
- SER Section 4: Time-Limited Aging Analyses (TLAAs)

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Overview (LRA)

- License Renewal Application (LRA) submitted June 2007
  - Located 26 miles southeast of the Augusta, Georgia, in Burke County, Georgia
  - Westinghouse PWRs, carbon steel-lined concrete (DRYAMB) containment
  - Each Unit rated at 3565 megawatt thermal, 1208 megawatts electric (prior to MUR uprate.)
  - Unit 1 Facility Operating License Number NPF-68 expires January 16, 2027
  - Unit 2 Facility Operating License Number NPF-81 expires February 9, 2029

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Overview (SER)

- Safety Evaluation Report (SER) issued to the applicant
  - 87 RAI items issued
  - 173 Audit Questions
  - AMR line items ≈87% Consistent With GALL Report, Revision 1
  - 41 Commitments
  - Additional Components Brought Into Scope
  - No Open Items (OIs)
  - No Confirmatory Items

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Audits and Inspections

- Scoping and Screening Methodology Audit
  9/17 – 9/21, 2007
- Aging Management Program (AMP) Audit
  10/15 – 10/19, 2007
- Aging Management Review (AMR) Audit
  12/9 – 12/14, 2007
- Region II Inspection (Scoping and Screening & AMP)
  5/19/ – 06/06, 2008

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Audit and Review

- Audit Summary (ADAMS Accession No. ML080430373)
  - Publicly Available, Issued on September 30, 2008
  - Audit Summary Includes :
    - Audit and Review Results
    - Audit and Review Q&A Database
    - List of Documents Reviewed by the Audit and Review Team

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SER Section 2: Structures and Components Subject to Aging Management Review

Section 2.1 Scoping and Screening Methodology

- Staff's audit and review concluded that the applicant's methodology is consistent with the requirements of 10 CFR 54.4 and 54.21.

Section 2.2 Plant-Level Scoping Results

- Consistent with 10 CFR 54.4, the staff found no omission of plant-level scoping systems and structures within the scope of license renewal.

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SER Section 2: Structures and Components Subject to Aging Management Review

Section 2.3 Scoping and Screening Results: Mechanical Systems

98 Mechanical Systems

- 34 BOP

- 100% Reviewed
  - Based on RAIs, three ventilation components were added to the scope

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SER Section 2: Structures and Components Subject to Aging Management Review

Section 2.4 Scoping and Screening Results: Structures

No omission of structural components within the scope of license renewal

Section 2.5 – Electrical and Instrumentation and Control Systems

- No omission of electrical and instrumentation and control system components within the scope of license renewal

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License Renewal Inspections

Louis Lake

Region II

Inspection Team Leader

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License Renewal Inspections

- Scoping and Screening Inspection
- Objective
- Focus

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License Renewal Inspections Program Implementation

- License renewal chapter - MC 2516

- License renewal inspection procedure IP 71002

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Aging Management Programs (AMPs) Implementation

- Objective

- Examine records

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Aging Management Programs (AMPs) Implementation

- Examine implementation plans

- Verify material condition of plant was adequately maintained

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License Renewal Inspection

- AMP inspection May 19 – June 6, 2008
- Inspection concluded that existing programs for license renewal are generally functioning well.

License Renewal Inspection

- Inspectors identified enhancements
  - Manhole flooding with Medium Voltage Non-Safety Related Cable
  - Condition inside containments

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License Renewal Inspection

- Applicant had established AMP implementation plans

- Region II will follow up on these issues during a future IP 71003 inspection

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Current Performance

- Green PIs & Findings
- Mid-Cycle Performance Review

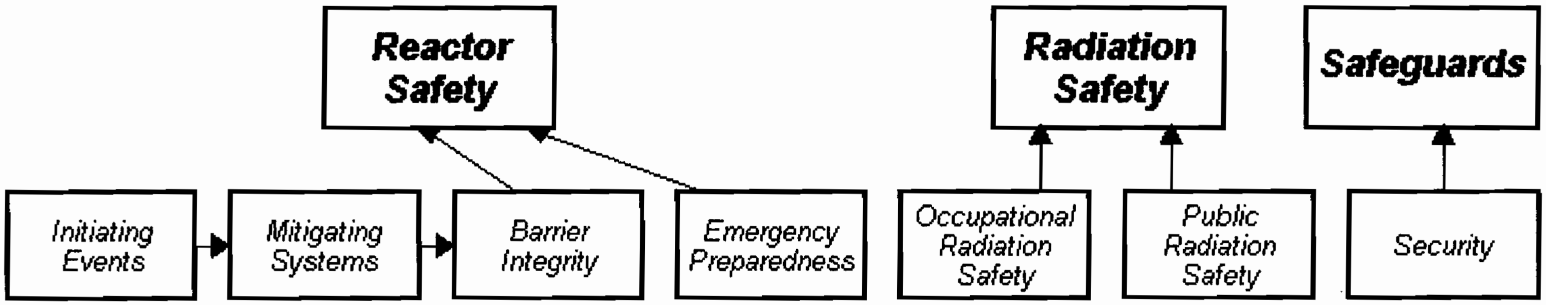
VEGP Units 1 and 2 Performance Indicators

Reactor Safety				Radiation Safety		Safeguards
Initiating Events	Mitigating Systems	Barrier Integrity	Emergency Preparedness	Occupational Radiation Safety	Public Radiation Safety	Security

Performance Indicators

Initiating Events	Mitigating Systems	Barrier Integrity	Emergency Preparedness	Occupational Radiation Safety	Public Radiation Safety	Security
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]		[redacted]			
	[redacted]					
	[redacted]					
	[redacted]					

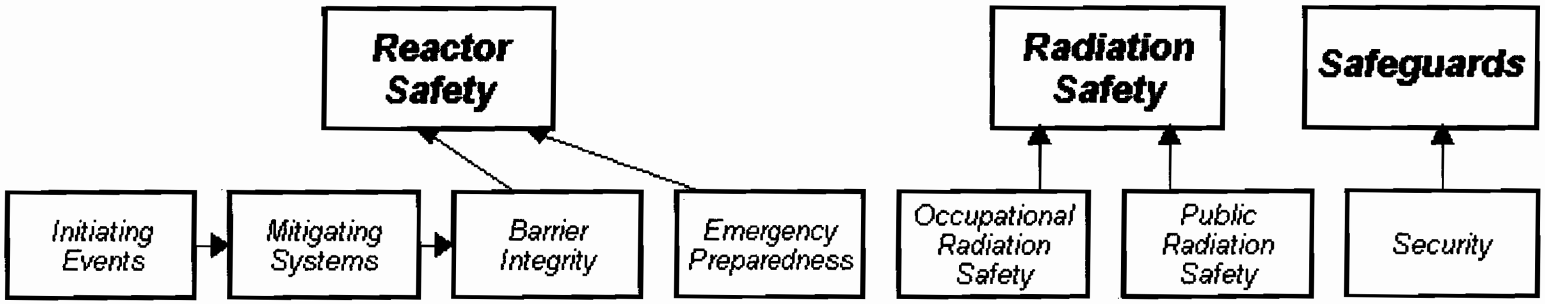
VEGP Unit-1 Findings



Most Significant Inspection Findings

3Q/2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2Q/2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1Q/2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4Q/2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

VEGP Unit-2 Findings



Most Significant Inspection Findings

3Q/2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2Q/2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1Q/2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4Q/2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Inspection Results

- No violations identified

- Inspection findings:

  - Condition of coatings inside containment

  - Manhole flooding

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SER Section 3: Aging Management Review Results

Section 3.0.3 Aging Management Programs (AMPs) evaluated in the SER

	Plant specific	Consistent with GALL	With exception	With enhancement	With exception & enhancement
Existing	6	5	3	5	5
New	5	3	6	0	0

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Section 3.1 Aging Management of Reactor Vessel, Reactor Vessel Internals, and Reactor Coolant System

- reactor vessel
- reactor vessel internals
- RCS and connected lines (includes the reactor coolant pumps)
- pressurizer
- SGs

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Section 3.2 Aging Management of Engineered Safety Features System

- containment spray system
- emergency core cooling system

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3.3 Aging Management of Auxiliary Systems

- fuel storage racks – new and spent fuel
- spent fuel cooling and purification system
- overhead heavy and refueling load handling systems
- nuclear service cooling water systems
- component cooling water system
- auxiliary component cooling water system
- turbine plant cooling water system
- river intake structure system
- compressed air systems
- chemical and volume control and boron recycle systems
- ventilation systems – control building (CB)
- ventilation systems – auxiliary building (AB)
- ventilation systems – containment building (CTB)
- ventilation systems – fuel handling building (FHB)
- ventilation systems – diesel generator building
- ventilation systems – auxiliary feedwater pumphouse
- ventilation systems – miscellaneous
- ventilation systems – radwaste buildings
- fire protection systems
- emergency diesel generator system
- demineralized water system
- hydrogen recombiner and monitoring system
- drain systems
- potable and utility water systems
- radiation monitoring system
- reactor makeup water storage tank and degasifier system
- sampling systems
- auxiliary gas systems
- chilled water systems
- waste management systems
- thermal insulation
- miscellaneous leak detection systems

3.4 Aging Management of Steam and Power Conversion Systems

- main steam system
- feedwater system
- SG blowdown processing system
- auxiliary feedwater system
- auxiliary steam system

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3.5 Aging Management of Containments, Structures, and Component Supports

- containment structures
- auxiliary, control, fuel handling and equipment buildings
- emergency diesel generator structures
- turbine building
- tunnels and duct banks
- NSCW structures
- concrete tank and valve house structures
- switch yard structures
- fire protection structures
- radwaste structures
- auxiliary feedwater pump house structures
- component supports and bulk commodities

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Section 3.5 Aging Management of In-Scope Inaccessible Concrete

Testing performed in November 2005 and May 2007 found:

	Acceptance Criteria	VEGP (2005-2007)	
		min	max
pH	>5.5	5.77	8.24
Chlorides (ppm)	<500	1.95	8.71
Sulfates (ppm)	<1500	2.9	12.5

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3.6 Aging Management of Electrical and Instrumentation and Controls System

- cable connections (metallic parts) not subject to 10 CFR 50.49 EQ requirements
- conductor insulation for electrical cables and connections not subject to 10 CFR 50.49 EQ requirements
- conductor insulation for inaccessible medium-voltage cables not subject to 10 CFR 50.49 EQ requirements
- connector contacts for electrical connectors exposed to borated water leakage not subject to 10 CFR 50.49 EQ requirements
- fuse holders (not part of a larger assembly): insulation not subject to 10 CFR 50.49 EQ requirements
- fuse holders (not part of a larger assembly): metallic clamps
- high voltage insulators
- switchyard bus and connections
- transmission conductors and connections

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SER Section 4: Time-Limited Aging Analyses

- 4.1 TLAA Process
- 4.2 Reactor Vessel Neutron Embrittlement
- 4.3 Metal Fatigue
- 4.4 Environmental Qualification of Electrical Equipment
- 4.5 Concrete Containment Tendon Prestress
- 4.6 Containment Liner Plate Metal Containments and Penetration Fatigue
- 4.7 Other Plant Specific TLAA

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Section 4.2 Reactor Vessel Neutron Embrittlement Analyses

Reviews were performed to evaluate reactor vessel neutron fluence and the corresponding vessel embrittlement in terms of adjusted reference temperature (ART) and:

- Upper-shelf energy
- Pressurized thermal shock
- Pressure-temperature limits

The staff concludes that the reactor vessel neutron embrittlement analyses meet the review criteria in the Standard Review Plan.

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Upper Shelf Energy (USE) Decrease

Reactor vessel limiting material	Fluence $x10^{19}$ n/cm^2 (E>1.0 MeV)	Unirradiated USE (ft-lb)	Predicted USE Decrease (10CFR50 apdx. G., %)	<u>56.3 EFPY Projected USE (ft-lb)</u>	<u>EOL USE Acceptance Criteria (ft-lb)</u>
Unit 1 Nozzle-to-Intermediate Shell Plate Circumferential weld 103-21	**0.0532**	**70**	**12**	**61**	**≥ 50**
Unit 2 Shell Course Weld 105-121A	**0.0455**	**64**	**11**	**56**	**≥ 50**

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Reactor Vessel RT_{PTS}

	60 calendar years 56.3 EFPYs Unit 1 / Unit 2	RT_{PTS} 10 CFR 50.61 screening
Fluence E > 1.0 MeV	3.2×10^{19} n/cm^2 / 3.02×10^{19} n/cm^2	--
Calculated RT_{PTS}	**123.3°F / 134.2°F**	**≤ 270°F**

- The limiting reactor vessel material is Intermediate Shell Plate Heat Number B8805-2 for Unit 1 and Nozzle Shell Course R3-3 for Unit 2.
- The calculational fluence methodology adheres to the guidance of RG 1.190.

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Additional TLAAs

- 4.3 Metal Fatigue Analyses
- 4.4 Environmental Qualification of Electrical Equipment
- 4.5 Concrete Containment Tendon Prestress
- 4.6 Containment Liner Plate Metal Containments and Penetration Fatigue

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4.7 Other Plant Specific TLAA

- 4.7.1 Leak Before Break Analysis
- 4.7.2 Fuel Oil Storage Tank Corrosion Allowance
- 4.7.3 Steam Generator Tube, Loss of Material
- 4.7.4 Cold Overpressure Protection System
- 4.7.5 Underclad Cracking of Reactor Pressure Vessel

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Conclusion

On the basis of its review, the staff determines that the requirements of 10 CFR 54.29(a) have been met.

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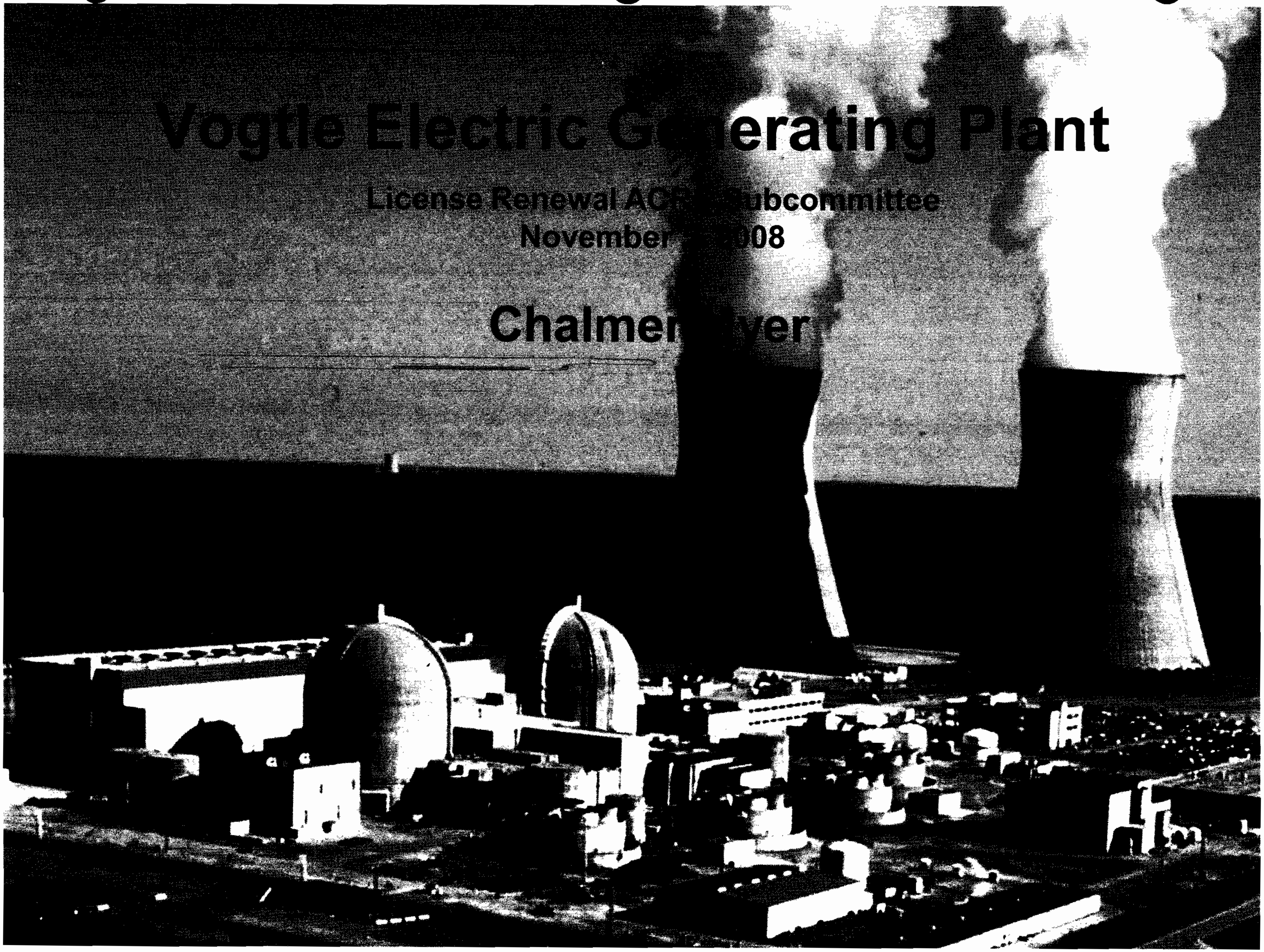
License Conditions

- The first license condition requires the applicant to include the UFSAR supplement required by 10 CFR 54.21(d) in the next UFSAR update, as required by 10 CFR 50.71(e), following the issuance of the renewed license.

- The second license condition requires future activities identified in the UFSAR supplement to be completed prior to the period of extended operation.

- The third license condition requires that all capsules in the reactor vessel that are removed and tested meet the requirements of American Society for Testing and Materials (ASTM) E 185-82 to the extent practicable for the configuration of the specimens in the capsule. Any changes to the capsule insertion and withdrawal schedule, including use of spare capsules, must be approved by the staff prior to implementation. All capsules placed in storage must be maintained for future insertion. Any changes to storage requirements must be approved by the staff, as required by 10 CFR Part 50, Appendix H.


Vogtle Electric G erating Plant
License Renewal AC ubcommittee
November 008
Chalmer yer

Agenda

SOUTHERN COMPANY

- Introductions
- Description of VEGP and Current Status
- License Renewal Project
- Inspection Results (NRC Region II)
- Summation and Questions

VEGP Representatives

SOUTHERN COMPANY

- Tom Tynan, Site Vice President
- Lee Mansfield, Engineering Support Manager
- Chalmer Myer, License Renewal Project Manager

Site Description

SOUTHERN COMPANY

- Westinghouse (NSSS), Bechtel (AE)
- Two 4 Loop PWR Units
  - 3625 MWt
  - 1250 MWe
- Ultimate Heat Sink – NSCW Forced Draft Cooling Towers and Basins
- Turbine Cycle Cooling Provided By Natural Draft Towers

Ownership

SOUTHERN COMPANY

- Plant Licensee and Operator
  - Southern Nuclear Operating Company
- Plant Owners
  - Georgia Power Company (45.7%)
  - Oglethorpe Power Corporation (30%)
  - Municipal Electric Authority of Georgia (22.7%)
  - City of Dalton, Georgia (1.6%)

Licensing History

SOUTHERN COMPANY

	Unit 1	Unit 2
◆ Construction Permit	June 1974	
◆ Operating License	Jan 1987	Feb 1989
◆ Stretch Power Uprate (4.5%)	March 1993	
◆ License Transfer to SNC	March 1997	
◆ LRA Submitted	June 2007	
◆ MUR Power Uprate (1.7%)	January 2008	
◆ Operating License Expires	Jan 2027	Feb 2029

Current Plant Status

SOUTHERN COMPANY

- Unit One
  - Completed refueling outage 14 in April 2008
  - 18 month average Capability Factor 92%
- Unit Two
  - Completed refueling outage 13 in Oct. 2008
  - 18 month average Capability Factor 90%

VEGP License Renewal Project

SOUTHERN COMPANY

- VEGP License Renewal
  - 10 CFR 54.17(c) Exemption
  - Project Team
  - Scoping Highlights
  - Aging Management Reviews
  - Aging Management Programs
  - VEGP AMP Exceptions
  - Time Limited Aging Analyses
  - Commitments

VEGP License Renewal Project

SOUTHERN COMPANY

- 10 CFR 54.17(c) Exemption
  - NRC granted VEGP an exemption to 10 CFR 54.17(c) to submit Vogtle Unit 2 License Renewal Application prior to reaching 20 years remaining on the operating license
    - Basis: Unit 2 is the same design and construction as Unit 1

VEGP License Renewal Project

SOUTHERN COMPANY

◆ License Renewal Project Team

- In house project team
  - Core team from Hatch/Farley LR
  - Vogtle experience added for VEGP LR
  - Expanded on success of previous applications
- LR Team engaged with the industry
  - Working groups (NEI, EPRI)
  - Participated in audits/inspections of peer plants
  - Supported LR peer reviews
- Site program owners involved in process
- No SER open items

VEGP License Renewal Project

SOUTHERN COMPANY

- ◆ Scoping Highlights
  - Performed consistent with NEI 95-10 Rev 6
  - Conservative spaces based approach used for (a)(2) scoping for spatial interaction
  - Mechanical boundary drawings included (a)(1), (a)(2) and (a)(3) scoped components
  - SBO – Scoping of switchyard SSCs consistent with NRC Staff Guidance

VEGP License Renewal Project

SOUTHERN COMPANY

- Aging Management Reviews
  - Followed NEI 95-10 guidance for AMRs
  - Made extensive use of GALL
    - 86% of AMR items consistent with GALL
    - Non-GALL items primarily material, environment or aging effect not in GALL

VEGP License Renewal Project

SOUTHERN COMPANY

- Aging Management Programs
  - 38 Aging Management Programs
    - 9 existing programs with no change
    - 15 existing programs with enhancements
    - 14 new programs
  - 27 GALL Programs
    - Only minor exceptions
    - Plant specific programs incorporated GALL attributes where possible

VEGP License Renewal Project

SOUTHERN COMPANY

- VEGP AMPs – Typical Exceptions to GALL
  - Use of a different version of a code or standard (consistent with VEGP CLB)
  - Manages material/environment not in GALL
  - AMP scope differences
  - Use of alternative inspection methods

VEGP License Renewal Project

SOUTHERN COMPANY

- Metal Fatigue
  - VEGP program currently uses FatiguePro
  - VEGP has committed to implement benchmarked software to manage fatigue prior to the period of extended operation.

VEGP License Renewal Project

SOUTHERN COMPANY

- Commitment Management
  - 39 commitments made to enhance aging management at VEGP
  - Commitments are tracked through Vogtle Commitment Tracking Program
  - License Renewal Program Manual will link AMPs and commitments

Inspection Results

SOUTHERN COMPANY

- Region II Site Inspection
  - Performed walkdown of Boric Acid Corrosion Control Program during 1R14 (April 2008)
  - Team on site for two weeks in May/June 2008
  - VEGP enhanced two existing programs as a result of comments from the inspectors

Inspection Results

SOUTHERN COMPANY

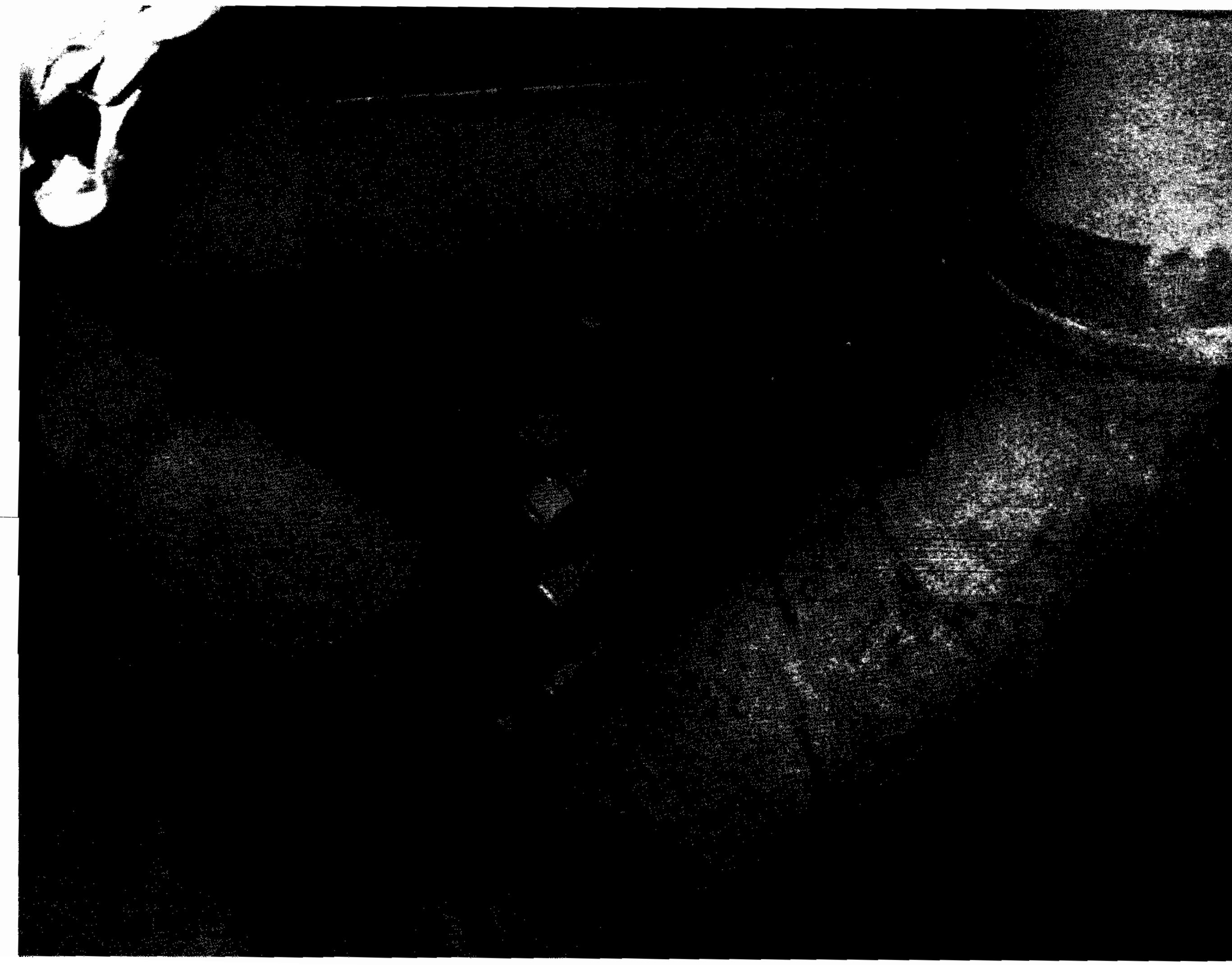
- Boric Acid Corrosion Control Program (BACCP)
  - Inspection concluded BACCP would adequately manage boric acid corrosion
  - However inspector noted non boric acid deposits from NSCW system condensation that could mask BAC
  - Corrective actions to be implemented
    - Systematic inspection, cleaning and repainting program
    - Procedure changes and enhanced communication
    - Evaluate system improvements to control condensate

Inspection Results

SOUTHERN COMPANY

Inspection Results

SOUTHERN COMPANY



Inspection Results

SOUTHERN COMPANY

- Medium Voltage Cables
  - In scope medium voltage cables at VEGP are located in tunnels and not subject to submergence, with one exception
    - Non-safety related 4kV feeders to high voltage switchyard switch house
  - Inspection found water in pull box near switch house
  - Corrective action - implemented LR aging management program
    - Quarterly inspection
    - Trending of results

Summary

- Experienced team created high quality LRA
- Extensive use made of GALL
- Thorough and successful audits and inspection of the LRA and programs
- VEGP responsive to NRC through out review
- VEGP is prepared to manage aging beyond 40 years