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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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PLANT LICENSE RENEWAL SUBCOMMITTEE

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WEDNESDAY

SEPTEMBER 19, 2012

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 8:30 a.m., John D. Sieber, Chairman, presiding.

COMMITTEE MEMBERS:

JOHN D. SIEBER, Chairman

J. SAM ARMIJO

HAROLD B. RAY

WILLIAM J. SHACK

GORDON R. SKILLMAN

JOHN W. STETKAR

CONSULTANT TO THE SUBCOMMITTEE:

JOHN J. BARTON

NRC STAFF PRESENT:

KENT HOWARD, Designated Federal Official

BART FU

MELANIE GALLOWAY

BRIAN HARRIS

ALLEN HISER

BILL HOLSTON

BENNY JOSE

JOHN LUBINSKI

JEFF POEHLER

ANN MARIE STONE

ALSO PRESENT:

BARRY ALLEN

RICHARD BAIR

DENNIS BLAKELY

JOE BRUNKHORST

KEN BYRD

DAVID CHEW

CHONG CHIU

CLIFF CUSTER
ALVIN DAWSON
STEVE DORT
TRENT HENLINE
LARRY HINKLE
JAKE HOFELICH
JON HOOK
ERIC JOHNSON
DON KOSLOFF
ALLEN McALLISTER
MARK RINCKEL
FRANK ZURVALEC

T-A-B-L-E O-F C-O-N-T-E-N-T-S

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

8:28 a.m.

CHAIRMAN SIEBER: Good morning. The meeting will now come to order. This is a meeting of the Davis-Besse Nuclear Power Station Plant License Renewal Subcommittee.

My name is Jack Sieber and I'm Chairman of the Davis-Besse Plant License Renewal Subcommittee. ACRS members in attendance are Bill Shack, John Stetkar, Sam Armijo, Harold Ray and Gordon Skillman. Also with us today is John Barton, who is a consultant to the ACRS. Kent Howard of the ACRS staff is the Designated Federal Official for this meeting.

The Subcommittee today will review the license renewal application for Davis-Besse Nuclear Power Station and the associated staff Safety Evaluation Report with open items. I note that the current draft of the SER contains four open items which must be satisfactorily resolved prior to the hearing of this application by the full ACRS Committee which is currently scheduled for next March. These open items relate to containment, concrete cracking issues, use of operating experience to update the tests and examinations that the licensee will perform during the renewal period, and reactor vessel integrity issues.

Today's agenda contains time also to discuss these issues.

We will hear presentations from FirstEnergy Nuclear Operating Company representatives, the NRC staff, and other interested persons regarding this matter.

We have not received written comments and requests for time to make oral statements from members of the public regarding today's meeting.

The entire meeting will be open to public attendance.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register.

A transcript of this meeting is being kept and will be made available as stated in the Federal Register notice, therefore, I request that participants in this meeting use the microphones located throughout the meeting room when addressing the Subcommittee. The participants are requested to please identify themselves and speak with sufficient clarity and volume so that they may be readily heard.

We will now proceed with the meeting, and I call upon John Lubinski of the NRC staff to begin the presentation. John?

MR. LUBINSKI: Thank you, Jack. As stated, I'm John Lubinski. I'm the director of the Division of License Renewal. I started in this position last Monday. I have been with NRC for 22 years and most recently was the deputy division director of our Division of Inspection and Regional Support at NRR.

As stated, this is our ACRS Subcommittee meeting on Davis-Besse license renewal application. When the application was received, we initially established a 22-month schedule. That was to accommodate the concurrent review of the license renewal application with plant outages and the ability to support on-site audits.

Since that time we have modified the scheduled twice. The first item was in December of 2011 where the schedule was moved out two months. And this was due to delay in responses to RAIs, as well as a large number of follow-up items and RAIs. The second time was in March of this year where the schedule was delayed by another four months. And this was to resolve at that time 11 open items.

Since that time we have reached resolution on 7 of those 11 items, but there are 4 open items still in the application and the SER that was provided on July 30th of 2012. As stated, those four items are: The shield building cracking, which we did allow extra time in today's meeting for discussion; operating experience, which is an item that the ACRS Subcommittee and full Committee has seen previously in Limerick and Columbia applications; and then the vessel integrity issues related to pressure-temperature limits, as well as the upper shelf energy. These four open items will be the focus of the staff's discussion this afternoon.

This morning I'd like to introduce members of our management team in DLR that are here today. To my right is Melanie Galloway, the deputy director of the Division of License Renewal. We also have several branch chiefs in the division; Dennis Morey, Bo Pham, Mike Marshall, and Raj Auluck. We also have the branch chief from our Region III office, Ann Marie Stone.

When the staff does its presentation this afternoon, I will introduce the specific members that will be providing comments. We also have a large number of our staff here in the audience today that can step to the microphone and answer comments.

At this time what I'd like to do is turn the presentation over to FENOC, and specifically Barry Allen to introduce his folks.

MR. ALLEN: Thank you very much. Good morning, Mr. Chairman and Committee Members. We're very happy to be here this morning and we're looking forward to just good discussion, healthy dialogue on our license renewal application. We will provide you a little bit of background information on Davis-Besse for those of you who may not have been there before. We'll provide an overview of our application and our process that we've gone through. And as far as the four Safety Evaluation Report open items, we have plenty of information. Plan on having a good dialogue on that, healthy discussion and a fairly long discussion on the shield building laminar cracking to ensure that this Committee has a good full understanding of that issue as we do.

As I said, I'm Barry Allen and I'll let my team up here with me introduce themselves.

MR. BYRD: I'm Ken Byrd, the director of engineering at Davis-Besse.

MR. CUSTER: My name is Cliff Custer. I'm the project manager for FENOC license renewal.

MR. DORT: My name is Steven Dort. I'm a license renewal project lead.

MR. ALLEN: We're looking forward to a very healthy dialogue today and we're looking forward to entertaining your questions and satisfying your needs. And with that, I'll turn the presentation over to Mr. Byrd.

MR. BYRD: All right. I'm going to start out with a brief introduction of Davis-Besse. If you can go to the next slide, please. So the Davis-Besse site, we are located on the southwestern shore of Lake Erie. We're in Ottawa County, Ohio. It's a 954-acre site, and of that site 221 acres are for the plant structures and equipment and the rest of the site is a wildlife refuge.

So next slide, please. So a very quick background on our plant. Davis-Besse is a pressurized water reactor. We're a Babcock & Wilcox raised-loop design, 2817 megawatts thermal. And we did do a measurement uncertainly recapture power up rate in July of 2008, and that was a 1.6 percent upgrade. Our license is currently -- would expire on April 22nd, 2017. And as of today the plant's at 100 percent power and we've been on the line for 98 days. That's following our 17th refueling outage.

Next slide, please. So we have had -- at Davis-Besse we've had two outages in the last 12 months. We did have a mid-cycle outage which we conducted last October, and that was in order to replace the reactor vessel head. Then we had a refueling outage this spring. And in those two outages we made a number of upgrades and did a number of inspections, and I'm going to very briefly review some of the things we did to improve the plant over those two outages.

Obviously, we replaced the reactor vessel head, and that was the reason we shut down back in October for the mid-cycle outage. We replaced selected power cables during both of these outages. We replaced selected service water piping as part of our ongoing program to replaced service water piping. We replaced both emergency diesel generator exhaust pipes. We did some upgrades to prepare for our steam generator replacement, which will be coming up in 2014 in our 18th refueling outage. We upgraded the polar crane and we installed a Palfinger crane. And we also did our in-service inspection for the reactor vessel removal core support with no unacceptable limitations. And we performed an integrated leak rate test of the containment.

So at this point, I'm going to turn it over to Cliff Custer to provide an overview of the license renewal.

MR. CUSTER: Thank you, Ken. The application was developed with the FENOC core team that's been involved in working on license renewals since 2006. Davis-Besse program owners and subject matter experts were involved in the development of the application and the audit and inspection interviews, NRC staff calls, RAI responses, and commitment development. In addition AREVA supported us in development of the application. During the time of the development of the application we participated in NEI working groups and industry peer reviews.

Next slide. The application was submitted in August of 2010. It was developed using GALL Rev 1 standards, which were the standards at the time. There are 43 aging management programs. Twelve are new, four plant-specific. Thirty-one are existing, four are plant-specific. The 49 license renewal commitments and those commitments are included in the USAR Supplement, which is Appendix A of the LRA.

MEMBER SHACK: And when your license renewal application came in, you had 25 commitments.

MR. CUSTER: That's correct, and it jumped to 49, which is a large increment.

MEMBER SHACK: Is that -- what's the -- why do you attribute that large number of changes in commitments? I mean, was something incomplete about the original application?

MR. CUSTER: The application, as I said, was originally submitted to GALL Rev 1. GALL Rev 2 changes a lot of the additional specifics. A lot of our RAI responses in fact were formulated based on GALL Rev 2. A lot of those commitments came from that.

CHAIRMAN SIEBER: Would you conclude that you now comply with all Rev 2, or are there exceptions?

MR. CUSTER: I would say that there are some exceptions. There are -- we have eight programs with exceptions. And I think the regulator this afternoon will talk about he selectively reviewed application to GALL Rev 2 during the audits and inspections.

CHAIRMAN SIEBER: Yes, will you present want the character of those exceptions are today to us?

MR. CUSTER: I had not intended to. We could respond to some of those questions as they come through.

CHAIRMAN SIEBER: Okay.

MR. CUSTER: Yes.

CHAIRMAN SIEBER: Okay. So we'll see when the time comes.

MR. CUSTER: Okay.

CHAIRMAN SIEBER: Thank you.

MR. CUSTER: Our commitments will be managed by the FENOC commitment tracking program.

Next slide. On this slide are listed the audits and the inspections that were conducted. Our RAIs and responses addressed the differences primarily between GALL Rev 1 and GALL Rev 2, as I said. Our Safety Evaluation Report with open items was issued on July 31st of this year.

Next slide. Our SER open items. As we said, we have four SER open items. Reactor vessel neutron embrittlement is one. Pressure-temperature limits is another. The use of operating experience and management of the shield building is the final one.

Next slide. With respect to neutron embrittlement, the reactor vessel upper-shelf energy evaluation, originally we chose a mean value of 70 foot-pounds in projection to the 52 effective full power years upper-shelf energy. Based on questions from the staff, we later chose to use equivalent margins analysis to qualify our upper-shelf energy selections.

Next slide. The equivalent margin analysis is as listed. And we provided the response to the nozzle belt forging on June 14th. The upper-shelf forging was addressed in the LRA. The nozzle belt forging to the upper shelf circumferential weld and lower shelf forging to the Dutchman forging were just submitted September 14th. Those items are under review by the staff.

With respect to pressurizer-temperature limits, the staff had questions on the methodology used to establish pressurizer-temperature limits. Appendix G requires pressurizer-temperature limits to include all ferritic materials of the boundary, include discontinuities and nozzles, and evaluate non-beltline components which may have RT_{NDT} values that define a more restrictive lowest operating temperature.

Next slide. In our response we reviewed and provided our limits in accordance with 10 C.F.R. Appendix G, Reg Guide 1.99 Rev 2, using the methods in the approved topical report BAW-10046A.

And the bottom line is really on the next slide, Steve, that the reactor vessel closure head outlet nozzles and beltline region are the controlling regulations that regulate the P-T limits. Our response has been submitted and is under review by the staff.

With respect to operating experience, the Interim Staff Guidance LR-ISG-2011-05 was issued in March to address age-related degradation and aging management programs, inform and enhance programs. We reviewed the ISG, and our response brings us in compliance. Our changes will be flag aging-related OE, consideration of material, environment and aging mechanisms. We will revise our OE and corrective action programs to provide feedback to aging management program owners, identify training needs. Those responses have been submitted and we will be in alignment with the ISG. At this point in time our commitment is by the end of the year.

Next slide.

MR. BYRD: Okay. I'll be providing the discussion on the open item B.2.34 for the shield building. So what I'm going to do for this open item, first I'll briefly walk through the function and design of the shield building, talk about how we discovered laminar cracking, review the investigation of the cracking, describe how we went about doing the root cause, corrective actions and then discuss the aging management program that we've put in place.

MEMBER STETKAR: Ken, can I interrupt you just for a second? I want to ask Jack something.

In terms of organizing the meeting, do you want to go through all of the shield building first? I have questions on other issues that they're not going to present in their formal slides here. You want to get those out of the way first, or you want to go through the shield building and then catch up on those after the shield building?

CHAIRMAN SIEBER: I would prefer to discuss the shield building now.

MEMBER STETKAR: Okay.

CHAIRMAN SIEBER: Because I think it's going to take the longest --

MEMBER STETKAR: Yes, that's --

CHAIRMAN SIEBER: -- amount of time. And --

MEMBER STETKAR: We have all -- I'm sure John has some also, so --

CHAIRMAN SIEBER: -- there are still significant questions. Okay. Just keep your questions noted.

MEMBER STETKAR: Don't worry. I have --

CHAIRMAN SIEBER: Oh, that whole book?

MEMBER STETKAR: I have notes.

CHAIRMAN SIEBER: Okay.

MR. BYRD: Okay. Go to the next slide, please. Okay. What this slide is intended to show is the shield building, the annulus and the containment vessel. And the important thing I wanted to -- point

I wanted to make here is our shield building at Davis-Besse is a freestanding concrete structure. We have a separate containment vessel that's shown in this slide. The containment vessel is an inch-and-a-half thick steel, and the function of the containment vessel is to be able to withstand the pressure for the largest postulated break we would have in the reactor coolant system. We have a four-and-a-half-foot annulus between the containment vessel and the shield building.

Go to the next slide, please.

MEMBER SHACK: While you're here, could you just show me the geometry of the sand pocket?

MR. BYRD: Yes, the sand pocket would be located in this area between the shield building and the containment vessel. So it's down in this location here.

MEMBER SHACK: And how big is it?

MR. BYRD: Well, the annulus itself is approximately four-and-a-half feet across.

MEMBER SHACK: And the sand pocket goes down how far?

MEMBER STETKAR: Ken, you have to speak into the microphone.

MEMBER SHACK: You have to be a little bit closer to the microphone.

MR. BYRD: I'm sorry. The annulus is four-and-a-half feet, and so the sand pocket would encompass that. As far as the depth of the sand pocket, maybe Mr. Hook could help me with that. Jon Hook, our design engineer and manager.

MR. HOOK: Right, I'm Jon Hook, design engineer and manager. So the sand pocket region is approximately -- tapered. At the top it is approximately 15 inches wide and at the bottom it's about nine inches wide. It's about four feet deep.

The sand pocket, I just want to clarify, we call it the sand pocket because at one time there was sand in it, but the sand has been removed. But we still call it the sand pocket area.

CHAIRMAN SIEBER: Have you found accumulations of water in the annular space between the building and the containment vessel?

MR. BYRD: We have. John, you want to continue with answering that question, please?

MR. HOOK: Can you repeat that question for me, please?

CHAIRMAN SIEBER: Have you found accumulations of water between the shield building structure and the containment vessel?

MR. HOOK: Yes, there is some minor seepage coming up in that area. We've been monitoring that. We look at it every refueling outage.

CHAIRMAN SIEBER: And is it enough water so that the containment vessel is wetted most of the time?

MR. HOOK: That access is -- that area is only accessed to us during the refueling outage. So we do take that opportunity at that time to go in and inspect that area. And it is wetted, but the slope is such that the water is -- flows away from the shield building. So normally there's not water progressing up against the metal.

DR. BARTON: Yes, but at one time there was, right? Don't you have some corrosion down there?

MR. HOOK: Right, there is some minor discoloration and corrosion down there.

DR. BARTON: What is minor? Have you done UTs or anything like that?

MR. HOOK: We did extensive investigation in 2002. We did UT readings back then and all the UT readings were greater than the minimum thickness required. And we've done -- like I said, we've done inspections every refueling outage and there's no significant change from 2002.

CHAIRMAN SIEBER: Well, since there's

access to the containment, the steel containment vessel at the bottom, is there concrete or any kind of obstruction in that area that would prevent you from getting thickness measurements throughout the bottom of the containment vessel?

MR. HOOK: Right, so when you look on the drawing there, the bottom portion of the containment vessel is encased in concrete on the top and on the bottom of it.

CHAIRMAN SIEBER: And so how do you get thickness measurements and defected --

MR. HOOK: Right, so --

CHAIRMAN SIEBER: -- limitations through the concrete.

MR. HOOK: In 2002 we did UT readings down at the sand pocket area.

CHAIRMAN SIEBER: Okay.

MR. HOOK: Those were the exposed shield -- the exposed areas. We didn't do any excavation in that area.

CHAIRMAN SIEBER: Okay. So you went down from the four-foot space between the shield building and the containment vessel, and around that curve made measurements basically perpendicular to the lower surface of the containment vessel?

MR. HOOK: The areas that are inaccessible due to concrete up against it we did not get UT readings. But from the outside at the bottom of the sand pit we could take UT readings. We had access to that area in the sand pocket region.

MEMBER ARMIJO: It's my understanding you're going to do some boring in the future --

MR. BYRD: That's correct.

MEMBER ARMIJO: -- to look for corrosion of the containment vessel due to borated water seepage.

MR. BYRD: We have a commitment; that's correct, to do a core bore, and that would be from the inside down to the containment vessel. And so it'll be from in here up to the --

MEMBER SHACK: It's at that little step, the thinnest part there?

MR. BYRD: It would be -- I'm not sure exactly. This is obviously --

MEMBER SHACK: Can't see where you're pointing.

MR. BYRD: It would be in this region. We'd be coming from down underneath the reactor going down to the --

MEMBER STETKAR: Maybe you could use the mouse? Yes, so everybody can see.

MR. BYRD: So we'd be taking a core bore from the region below the reactor vessel and going down to access the containment vessel. So the core bore would be going down through the concrete. And that's -- we have that, and we're committed to performing that prior to the 18th refueling outage in 2014.

MEMBER STETKAR: But that won't be at the low point of the containment vessel.

MR. BYRD: That would be --

MEMBER STETKAR: That's about 30 inches above the --

MR. BYRD: No, I'm not sure if it is. Maybe -- it says 30 inches.

MEMBER STETKAR: Well, it is 30 inches.

MR. BYRD: I think we have -- Dick Bair can answer that.

MR. BAIR: My name's Richard Bair. Work in design engineering. Our plan is in the 18th refueling outages to install the core bore through the concrete in the under-vessel area to access the inside base of the containment vessel for inspection for potential boric acid effects. It will not be through the -- necessarily through the lowest portion. The least amount of concrete between the vessel that we can go through is our containment sump that has a stainless steel liner. We don't wish to perforate that, nor put in this core drill. So we're going to be somewhat off from that area going through approximately two feet of concrete to access the inside face of the vessel for inspection.

CHAIRMAN SIEBER: Now you have a history of leaks that the reactor vessel had at the attachments through the control rod drive mechanisms. Do you have evidence on the concrete basemat of the containment that borated water was able to leak down to that level in the containment?

MR. BYRD: I'm not -- do we have a -- Mr. Hook?

MR. HOOK: So we do do inspections in that area and the leakage through the refueling canal, when we have the refueling canal filled, it's relatively minor. We do inspections and we have found no deterioration at all in the concrete area.

CHAIRMAN SIEBER: Did you find evidence of boric acid deposits there?

MR. HOOK: We have evidence of boric acid deposits on the concrete. There's a few cracks where it has come up.

MR. CHEW: My name is David Chew. I'm the refueling canal system engineer and also a boric acid inspector.

What we've done is in past outages, or in -- and in current outages now we do documented boric acid inspections. When we go into containment when we first start a refueling outage we do an as-found inspection, take pictures, document that it in an inspection report. We take -- when the canal is filled after a few days, we go back in, do another as-found inspection, do pictures and an inspection report.

Then when it is drained, we go in and decon the area, clean it up and then do an as-left inspection, take those pictures, document that. And then the next outage when we come back, we do our initial as-found. The pictures are compared, the documents are compared to see if there's any changes. And in the past several outages we haven't seen any changes, any further degradation.

CHAIRMAN SIEBER: When was the -- when did you last perform the integrated containment leak rate test?

MR. BYRD: We performed an integrated containment leak rate test during our last refueling outage.

CHAIRMAN SIEBER: And what was your initial result? Did you have to repair anything?

MR. BYRD: Actually 2011 it was.

MR. ALLEN: It was 2011. It was the mid-cycle outage. I'm sorry, the mid-cycle outage was -- the mid-replacement outage.

CHAIRMAN SIEBER: Were you required to repair anything to meet the requirements of that test?

MR. BYRD: Mr. Henline, Trent Henline, our program supervisor can provide some more information on that.

MR. HENLINE: My name's Trent Henline, engineering program supervisor. And we provided our integrated leak rate rest during the 17th mid-cycle in November of 2011. And we passed that test on the initial attempt with an approximately 80 percent margin. We did not have to repair anything.

CHAIRMAN SIEBER: Okay. Thank you.

MEMBER STETKAR: Jack, I want to ask a couple of questions, as long as you brought it up, on the containment shell.

The water that you found in the annulus is groundwater, is that correct?

MR. BYRD: That's correct.

MEMBER STETKAR: And you've got a fairly aggressive groundwater chemistry at the site, as I understand it.

MR. BYRD: That's correct.

MEMBER STETKAR: I understand you've inspected the parts of the shell that you can access right at the interface there. What confidence do you have that groundwater has not migrated to the bottom part of that area and initiated corrosion from the exterior part of the shell in an area -- what's the surface area at the bottom of the containment shell that you won't be able to access during that single core bore from the interior? In other words, there's a big dish there that water could be collected for some period of time that you have no evidence of the status of the shell in that area.

MR. BYRD: You're asking about water that would be migrating from the sand pocket region --

MEMBER STETKAR: That's correct.

MR. BYRD: -- through the concrete?

MEMBER STETKAR: Well, or through -- it's not air-tight. Through the gap between the concrete and the shell.

MR. BYRD: Okay. I understand. I'll have -- Jon Hook can address that issue.

MR. HOOK: Right. I'm Jon Hook, design engineer and manager. I think your question is related to corrosion on the underside of the containment vessel.

MEMBER STETKAR: That's exactly right.

MR. HOOK: Right. So there is groundwater infiltration. The foundation that we have underneath there is a waterproof membrane, but obviously there's either a tear or a rip in that. We've got water migrating in that area. Again, we monitor that area. In the sand pocket we take samples of the water every refueling outage, and based on the samples of the water that we have, we have very low iron content in there. The concrete is a very high pH area and it's very passive -- passivates any corrosion in that area. So based upon that, we -- there is very little if any corrosion in the inaccessible areas of the containment vessel.

MEMBER STETKAR: Well, you have drains in that area.

MR. HOOK: We have two drains in the sand pocket area, that is correct.

MEMBER STETKAR: How do you keep water out from the bottom? I'm not very well versed in --

MR. HOOK: Right, so there is --

MEMBER STETKAR: I'm an engineer. The bottom point of the --

MR. HOOK: There is a potential that we'll have water between the concrete foundation and the underside of the containment vessel.

MEMBER STETKAR: Right.

MR. HOOK: Right. And then water would be there and it migrates up through the interface between the containment vessel to the sand pocket area.

MEMBER STETKAR: Yes.

MR. HOOK: But again, that's exposed to the concrete that's there. Concrete is very passive to corrosion. There's very little if any oxygen in that area, so based upon the passive nature of the concrete, low oxygen content and monitoring the water in the sand pocket area, we have high confidence there is no corrosion going on in the vessel.

MEMBER STETKAR: That's presuming the water comes in from the low point and fills the entire volume. Is that right? I mean, if the water's coming in and flowing down, sampling the water in the sand pocket gives you absolutely no indication of possible corrosion products collected at the bottom.

MR. HOOK: Right, the water is coming up between the containment vessel on the underside and migrating up --

MEMBER STETKAR: Ah.

MR. HOOK: -- sand pocket area.

MEMBER STETKAR: Okay. And you know that?

MR. HOOK: We know that. That is for sure.

Again, we go in there every refueling outage, or every time we have an outage and then -- to verify that. The sand pocket --

MEMBER SHACK: Seems that you've left all the chlorides down somewhere in the -- all the -- the chlorides come in somewhere. There's a conservation of chloride going on somewhere here.

MR. HOOK: That is correct. We have high chlorides in that area.

MEMBER SHACK: Well, that's not a good thing.

MEMBER STETKAR: And from what you're saying, that must be continuously wetted then.

MR. HOOK: There are some regions -- there's five small areas that have some seepage in that area. So the far majority of that area is dry.

MEMBER STETKAR: Now that's where you see -- I'll use the term --

MR. HOOK: Migrating to the top.

MEMBER STETKAR: -- migrating to the -- thank you -- migrating to the -- I was going to use the term bubbling up, but migrating to the top. But what confidence do you have that the vast majority of the lower portion of that shell is not continuously wetted? Just because you see it in five locations doesn't necessarily mean that that's -- you know, that there are little rivulets coming up or something.

MR. HOOK: So there is a potential that a large area could be in contact with the water. But again, that large area is in contact with the concrete with a high pH. Very, very low oxygen content in that area. So based upon those items, corrosion's not taking place.

MEMBER SHACK: Those are good things, but then the high chloride's --

MEMBER STETKAR: Doesn't make you feel good.

MEMBER SHACK: -- not a good point.

MR. HOOK: Right, so there is chlorides in the groundwater. So --

MEMBER SHACK: It is apparently collecting since you're not seeing it in the stuff that's coming up. You told me that was low chloride. Un-aggressive, right?

MR. HOOK: There is chlorides in the water that we have sampled. And as the water comes up, there could be some evaporation and then concentration of the water that's in there. So the part that we see and we tested could be a concentrated area.

DR. BARTON: Where are these drains, these

-- you said five drains or something? Where are they located?

MR. HOOK: No, there's two drains.

DR. BARTON: Pardon?

MR. HOOK: There's two drains --

DR. BARTON: Where are they located and how big are they?

MR. HOOK: I think they're four-inch drains and they are located approximately on each side of the fuel transfer tube area.

DR. BARTON: In what amount?

MR. HOOK: And the sand pocket area is sloped to the floor drains.

DR. BARTON: Now can you get access through the drain lines with a boroscope or something and get down there and see what you got on the bottom?

MR. HOOK: The floor drains are accessible. They're on the bottom of the sand pocket.

MEMBER STETKAR: But they're just normal. I mean, it's a big annulus so there are just floor drains in there to collect leakage from pipes that come through and -- they're just floor drains.

DR. BARTON: Well, I'm just looking at access to the bottom of the --

MEMBER STETKAR: Yes, but they'll just go out. It hits the interface and that's it, yes. All right.

CHAIRMAN SIEBER: It has to go to a sump.

MEMBER STETKAR: Yes, they'll go out --

CHAIRMAN SIEBER: It's all underground.

MEMBER STETKAR: Yes, they'll go to a floor drain.

MEMBER ARMIJO: Well, you know, it would be helpful if we could get -- and I know this isn't the main shield building issue, but it's going -- we're going to come to that. That's one of the RAIs. We can probably hear more about that in future meetings. But the source of the infiltration of the water, if it's coming in through the bottom of the concrete -- you know, water normally doesn't flow up hill, so I don't know how it gets up to the sand pocket region unless it's leaking in near the sand pocket region.

MR. HOOK: The sand pocket area is approximately -- well, there's approximately 25 foot of head on the groundwater. So that's why the sand pocket --

MEMBER STETKAR: The normal groundwater level is 570, and this is 5 --

MR. HOOK: Five-forty-five.

MEMBER STETKAR: -- 545.

MEMBER ARMIJO: So that's leads to, not a conclusion, but a suspicion that there's plenty of water, I mean, in between the steel and the concrete.

MEMBER STETKAR: Right. Yes.

MEMBER SHACK: It's a question of how benign that environment is --

MEMBER ARMIJO: Yes, right.

MEMBER SHACK: -- with the concrete.

MEMBER ARMIJO: Right. Right, right, right. So that's the -- we got to get at that at some point in more detail to understand the chemistry.

MR. HOOK: Well, so one of the things that -- when -- Dick Bear talked about that. During the next refueling outage we're going to take a core bore at the bottom. And to get to the bottom of the containment vessel, we'll do new UT readings and at the bottom. Then we'll absolutely be able to determine the thickness as well.

MEMBER ARMIJO: So when you bore it, do your core bore, then you'll get -- do a UT and you'll get thickness at the location of where --

MR. HOOK: That is correct.

MEMBER ARMIJO: A low location? Not --

MEMBER SHACK: A low location. Thirty inches off the --

MEMBER ARMIJO: Not the absolute bottom.

MEMBER SHACK: Right. Right. But it will be low.

MEMBER STETKAR: It'll be low enough to see this effect from the groundwater.

MEMBER SHACK: I would think.

MEMBER STETKAR: You would think.

MEMBER ARMIJO: Well, this is something in a future presentation more detailed on how that's put to bed.

MEMBER RAY: How is the containment vessel supported? Is it just supported at the bottom by its embedment in the concrete, or is there any other support provided to the containment vessel above the sand pocket?

MR. HOOK: Yes, again, I'm Jon Hook, design engineer and manager. The containment vessel and the shield building are two separate complete structures. There's no interaction except for at the base. They share the same common foundation. And the containment vessel has concrete on the bottom, a significant mass of 15 feet of concrete at the bottom. It is a cantilevered structure.

MEMBER RAY: Okay. So it's freestanding above the foundation?

MR. HOOK: That is correct.

MR. BYRD: Okay. Any further questions on this before I move on?

(No response.)

MR. BYRD: Okay. I'll move on now to talk a little bit about the shield building.

So the shield building itself if a -- it's a 30-inch concrete structure. And the purposes of the shield building, there's really three primary purposes: One is biological shielding. Secondly, it provides environmental protection for the containment vessel. I mean by that protection from various different kind of missiles. And then it allows for a controlled release of the annulus under accident conditions. And we do have a ventilation system which can take a suction on the annular area and provide us with a negative pressure in that area.

Next slide.

DR. BARTON: I understand there's no waterproof membrane on the exterior of the shield building below grade.

MR. BYRD: That is not correct. There actually is a waterproof membrane on the shield building below grade. There is not a waterproof membrane on it above grade. It was constructed with a waterproof --

DR. BARTON: I must have read that wrong. All right.

CHAIRMAN SIEBER: But you doubt the integrity of the waterproof membrane below grade, right? Did I hear you say that before?

MR. BYRD: I didn't say that. I mean, I don't know that we've done -- I think, Joe Brunkhorst, maybe you could provide a little bit more information on that.

MR. BRUNKHORST: Joe Brunkhorst, structures monitoring program owner. As far as the waterproof membrane below grade, there is obvious evidence that there may be a nick or flaw or in the membrane, but it covers substantial surface area for below-grade shield building.

DR. BARTON: Well, if you're getting water into the concrete below grade, how do you know the condition of that concrete? You got to address the water down there.

MR. BRUNKHORST: That's correct. We haven't seen any signs of any sort of degradation, spalling from what has been accessible. I mean opportunistic inspections of the area has not shown any signs of any sort of aggressive groundwater attack on the concrete.

CHAIRMAN SIEBER: Have you had opportunistic inspection opportunities --

MR. BRUNKHORST: I can --

CHAIRMAN SIEBER: -- down below the -- on the curvature of the base of the shield building?

MR. BRUNKHORST: I do not believe so. We have not had any specific on the shield building itself, no.

CHAIRMAN SIEBER: Okay. Thank you.

MR. BYRD: Okay. Moving on, please, to the next slide. So the purpose of this slide is to provide you with a little bit of information on some of the terms we're going to be using here to describe the shield building cracking issue.

First of all, the shield building wall, as I've mentioned before, it is 30 inches thick. There's two mats of primary reinforcement bar on the shield building, an inner and outer mat. And those are No. 11 rebar horizontally, which is one-and-three-eighths inches, and No. 10 vertically.

We also have these -- eight of these flutes, which are labeled on this picture around the perimeter of the shield building. And around each flute we have two of what we have -- we call a flute shoulder. Now these three shoulders, the dimensions, it's approximately -- on the inside that's about 18 inches. And the flute shoulder has its own reinforcement, as you can see in the diagram. That's No. 8 rebar, one-inch diameter. And that rebar is -- it attaches to the main rebar in two locations on each end of the flute shoulder.

And the dimension between the two points of the rebar is -- it's about -- between 11 and 12 inches. We took quite a bit of -- 11 and 12 feet, rather. We took quite a bit of radar, ground-penetrating radar measurements of that during our evaluation of the condition.

CHAIRMAN SIEBER: What's the purpose of the flute?

MR. BYRD: The flute is only intended -- it's an architectural feature. It's only for aesthetics.

CHAIRMAN SIEBER: It's only for --

DR. BARTON: To make the building look pretty.

MR. BYRD: That's correct.

DR. BARTON: That's what it is.

CHAIRMAN SIEBER: Yes, that caused me to scratch my head.

DR. BARTON: We don't have those kind of

buildings.

MR. BYRD: And actually the next slide --

MEMBER ARMIJO: Before you do that, I just want to make sure, the only thing that hooks that shoulder to the rest -- to the structural part of the shield building are these rebar that comes through the wall, those --

MR. BYRD: Those -- on each end of the -- on each end those hooks. That is correct.

MEMBER ARMIJO: And down the length of the flute there's hooks?

MR. BYRD: This rebar is spaced every 12 inches horizontally, so you have a hook every 12 inches. But that's one of the factors I'll be discussing, because that was one of the contributing issues we had lack radial reinforcement on these flute shoulders.

MEMBER ARMIJO: Okay.

MR. BYRD: If you go to the next slide, it provides a little bit better information on the function of these flute shoulders.

So this is a picture of a flute shoulder taken up close. This is actually from the roof of our auxiliary building. And the interesting thing to note here is that the flute shoulder ends at the roof of the building. Actually only 3 of our flute shoulders out of 16 actually go down to ground level. All the rest of them are truncated like this one at various different roof levels. So this makes it pretty apparent that this was intended as an -- for aesthetic purposes. In our evaluation of the capability of the shield building, we don't take any credit for the flute shoulders. We do evaluate them as a dead load in our analysis.

The other interesting thing I just want to point out on this picture, you can see a lot of blue dots on the concrete there. That is the -- and I'll be talking about this a little bit more. That's the grid we laid out for the impulse response testing we did on the shield building. We actually laid out over 60,000 of those points. That's on a one-foot square.

The other thing of interest there, you can see in the middle of the flute on the upper left-hand side of this picture there's a red circle there, a little red dot. That's actually a plug. We did a core bore in that area and that's one of the plugs we use protect the core bores.

So next slide, please.

MEMBER ARMIJO: Just to make sure I understand. Now, the shoulders don't actually -- do not -- there's no shoulders, let's say in the protected areas? Let's say the -- with the auxiliary building the shoulders don't go down to there?

MR. BYRD: They don't go down. What you're --

MEMBER ARMIJO: Or the turbine building. They just stop?

MR. BYRD: They stop at the -- what you're -- what we're standing -- on this particular picture here, you're -- we're standing on top of the main steam line rooms at Davis-Besse. And if you go down underneath, there is no shoulder down there. This actually several feet above the roof line. And it does that everywhere where there's a building adjacent to the shield building. So there's actually only three flute shoulders which go down to ground level.

MEMBER ARMIJO: Okay. Thanks.

MR. BYRD: Okay. Next slide, please. So very briefly, we discovered this issue on October 10th. We were performing hydro-demolition. That was part of creating a construction opening for our head replacement. Upon discovery of the condition, we did notify the Nuclear Regulatory Commission resident, wrote a condition report and we placed a restraint on the restart. And then we put together a team of experts to investigate the issue. And for that we mobilized various different consultants. We also brought in experts from FirstEnergy.

MEMBER SHACK: Hydro-demolition, is that just a water jet cut?

MR. BYRD: That's the -- yes, hydro-demolition is the method we use. That's where we us 20,000 pounds per square inch water pressure to cut through the concrete.

Next slide, please. So one of the methods we use to investigate this condition was the methodology called impulse response, which is a non-destructive methodology that can be used in concrete. And the way this works is you have an instrumented hammer. And in this picture you can see the individual who is performing this testing. He has that hammer in his right hand. And they have a geophone then which they use to monitor the response, which in this case he has in his left hand. So what he'll do is he'll strike the wall at one of those blue dots which were gridded out. And then these -- the hammer and the geophone are both linked to a portable field computer which collects the data. And that information then is -- that data is processed to obtain a parameter that's called mobility, and that mobility can then be related to the structure thickness.

So in our total campaign -- again, we did actually a couple different campaigns. We did some impulse response testing in 2011 until the weather got -- you know, towards the end of the year. Then this summer we completed the rest of the building. We did about 60,000 individual points in the building with this methodology.

CHAIRMAN SIEBER: When you perform this test what frequency range are you intending to receive in the microphone-type device in the workman's left hand?

MR. BYRD: I couldn't answer that question. I don't believe I have anyone here that could answer that. That would be something I'd have to refer -- we used Construction Technology Laboratories. That's the organization in Chicago who performed this testing. So I'm not familiar with the specific frequency that was being --

CHAIRMAN SIEBER: And so what you're looking for is the reflections from the cracked surface, if any?

MR. BYRD: That's correct.

CHAIRMAN SIEBER: And how do you determine how deep the crack is?

MR. BYRD: The way you determine; I'm going to show that on the next page, you have to do a core bore, because impulse response testing cannot give you the depth of the crack. What can tell you is you have an area of high mobility, and then we would investigate those areas further using core bores.

CHAIRMAN SIEBER: Okay. So all this does is tell you where the cracks are? It doesn't characterize them in any way?

MR. BYRD: That is correct. Well actually, if you do a lot of this -- we could tell by looking at this -- and I -- it's not quantitative, but you could look at the results and say I know you have some cracking in this region. I mean, after we'd done this over the entire building, we gained a lot of experience. And obviously the Construction Technology people are very experience at this, but in order to validate this information, we used core bores.

MEMBER ARMIJO: What is the definition of "mobility?" What are you actually measuring?

MR. BYRD: It's the -- it's really a -- it's a measure of the structure. It's related to -- the structure thickness is what you're getting. So you can detect if you have a crack or a laminar -- delamination in that area.

MEMBER ARMIJO: So if you had some mobility parameter that you're measuring and you've taken all these data points, can you get a map of where this discontinuity --

MR. BYRD: Yes, and I'll be showing you a slide later which shows you the mobility mapping we did for the entire shield building.

MEMBER ARMIJO: Okay.

CHAIRMAN SIEBER: Now, from this portion of the test you cannot tell anything about the geometry of the crack?

MR. BYRD: That is correct.

CHAIRMAN SIEBER: For example, direction, depth, width. Those just do not appear in the test result?

MR. BYRD: That is correct. And I'll be talking a little bit more about that in my next slide, how we gained that information.

CHAIRMAN SIEBER: Well, I'll let you go a little further before I ask the next question.

MR. BYRD: All right. Very good. Thank you, sir.

Then go to my next slide where I talk a little bit about the other methodology we used. We used core bores extensively to investigate the condition. And this picture shows a typical core bore. Our core bores, you know, we varied them from two to four inches in width, depending on what we were attempting to do. They could be from 8 to 28 inches deep.

And there was really four reasons we used to do core bores. And first of all; and we discussed this, we used these to validate the impulse response data. And I might point out we did find that the impulse response data was very accurate. What we would frequently do, or we tried to as much as possible, is use pairs of core bores. So when we'd get to an area where the mobility told us that cracking was extended, we would put core bores as close together as a foot and we could get cracked and not cracked. So we could validate that the impulse response data was valid. And it was very accurately able to do that.

The second purpose of these was to establish the crack depth. Again, impulse response couldn't tell us how deep the crack was, but we could actually go down with the boroscope and we could look and see where the crack existed and measure the crack depth.

We could measure the crack width using the -- and we did that with the crack comparator, and I'll show you that on the next slide how we did that.

And finally, we took some of our core bores for material sampling for part of our root cause process, and I'll describe how we did that later on when I talk about the root cause.

CHAIRMAN SIEBER: Now this design is unique to the architect engineer for this facility?

MR. BYRD: The design of the shield building?

CHAIRMAN SIEBER: Yes.

MR. BYRD: It was unique for this -- there are other -- when I say "this design," there are several other plants that have freestanding shield buildings, but I'm not sure if any of them were precisely the same as Davis-Besse.

CHAIRMAN SIEBER: That have flutes?

MR. BYRD: There are other designs with flutes, but again not -- they're all a little different. There are some other plants that do have flutes that I'm aware of.

CHAIRMAN SIEBER: Has any other licensee with a containment building design like this found similar effects?

MR. BYRD: No, they have not, and -- although we have talked to some of them and some of them were actually up at Davis-Besse while we were doing the investigation. But when I get to the root cause, when I'm going to -- when I explain to you what caused this, there's a number of -- a series of what I would consider rather unique conditions that needed to occur in some of the other plants, for example, that may be in the South where we don't get the cold weather and some other things that may have had an impact on that. So at this point none of the other ones have observed this condition.

CHAIRMAN SIEBER: Yes, well cracking in a containment building is not a unique phenomenon.

MR. BYRD: Understand that. We'll -- again, when I get into the root cause, I can talk about what we --

CHAIRMAN SIEBER: Okay.

MR. BYRD: -- obtained from operating experience.

DR. BARTON: But their rebar design may have been different also.

MR. BYRD: That's possible, too.

DR. BARTON: Different designer.

MR. BYRD: Right.

CHAIRMAN SIEBER: Well, it can have -- it can be a design issue, it could be a concrete mix issue.

MR. BYRD: Right.

CHAIRMAN SIEBER: Or chemical reaction, or weather conditions, or -- there's a variety of things that can cause these.

MR. BYRD: Right, and we'll talk a little bit more about that. I'll get to the root cause portion.

MEMBER ARMIJO: When you pulled out the core when you were doing this core boring in a region where you had these cracks, did they come out where they actually came out in two pieces?

MR. BYRD: Yes, they would.

MEMBER ARMIJO: Okay.

MR. BYRD: When they were cracked, they would come out in two pieces. But really the way to measure the crack was actually going to the core bore and look in the bore itself.

MEMBER ARMIJO: After they were done?

MR. BYRD: After they were taken out, right. Sometimes you'd get them cracked where there wasn't a crack just trying to get out -- if you had a long core bore you're trying to pull out, it may crack.

MEMBER SHACK: Now I see Kewaunee and Prairie Island have similar constructions. At least they're still cylinders with concrete shield buildings that have your kind of weather.

MR. BYRD: Yes, I'm not sure either of them have flutes either though. I know there are flutes at some plants, and I'm not -- those two don't come to my mind as one that are fluted.

Okay. Going to the next slide, I can summarize now where we saw the cracking. So the drawing you see on this slide depicts the primary region where we saw cracking. So what we determined was that cracking is -- can be found in the flute shoulders. And I say it's generic. We found it -- it could be found at various different elevations in the flute shoulders. It was observed to be more prevalent and actually much -- significantly more prevalent -- and I'll show the map of the completed impulse response testing later on the south side of the building.

We did identify that the cracks were located in, as shown on this picture, near the outer reinforcing mat. There were no cracks observed on the inner mat. And to investigate the inner mat, first of all we had the construction opening. When we cut it, we had a 25-foot by 35-foot opening. We did inspect the perimeter. We did have a cracking on the outside. In fact, the picture here shows where the boundary of the construction up here was. So we actually cut right through the flute shoulder. We had no cracking observed on the inner mat. It was all on the out outer mat.

We also further validated that. We did eight deep core bores. So we did eight core bores and then all the way through to the inner rebar mat. And in none of those core bores did we find any cracking in the inner rebar.

CHAIRMAN SIEBER: Did any of the cracking appear on the surface where it --

MR. BYRD: No, it did not. This cracking was contained inside as shown on this picture in that inner mat of rebar. When I say "in the inner," it was in the vicinity of the inner rebar mat. It did not have any of the cracking that appeared on the surface. There was no way through a visual inspection we had this line in the cracking.

CHAIRMAN SIEBER: Okay. So you saw no spalling, no cracks on either side of the containment?

MR. BYRD: We saw no spalling or cracking that was associated with this laminar cracking. I mean, there was none.

Okay. Moving onto the next slide, so we also identified that we had some cracks in the top 20 feet of the shield building outside of the flute shoulder region. The way it appeared is it appeared -- and this is in -- and I'll -- this will be more obvious when I show you the map of the total cracking, the cracks had spilled out of the shoulders in the top 20 feet. And then we found two small regions; and these were adjacent to the main steamline penetration block-outs where we also found similar cracking. Now the main steamline penetration block-outs are actually the areas that are right adjacent; and again, the drawing will show that more clearly -- are adjacent to the regions where -- and in the shoulders.

And finally, we identified the cracks are very tight. And the method we used to measure crack width -- again, that was something we had to with the core bores. And we use the -- a core bore and we use crack width comparitor. And the picture you see here shows us with a -- measuring the width of the crack. And we photographed these using the boroscope. This particular crack we measured at 0.005 inches. So again, it's a very tight crack. All of the cracks except one were less than 0.01 inches. We did have one crack that was 0.013 inches. That was the only case we had that was greater than 0.01.

Okay. Next slide, please. So that really very briefly summarizes the condition that we identified. So I'll talk a little bit about -- next about the evaluation we did to determine that this -- the shield building was structurally adequate to restart the plant.

So first of all, the original steel building design is -- it's pretty conservative. It was constructed with significant reinforcement and there was a significant of margin. We had -- the maximum vertical stress on the rebar was only 32 percent of maximum in the vertical and about 50 percent horizontally. So there was considerable amount of margin.

So the concern we had though with these laminar cracks is a concern about the potential effect of the bond strength between the rebar and the concrete. Obviously that was because we had identified that the cracking was in the rebar mat. And in particular there was a concern where we had laps on the rebar, whether or not we'd have sufficient capability for those splices.

MEMBER SHACK: Do you know how long those laps are?

MR. BYRD: Yes, we do. The laps are in the lower portion of the building. The laps are 79 inches. That's the specification. And in the upper part of the building, they're 120 inches.

MEMBER SHACK: Now is that consistent with current code requirements? Three eighteen --

MR. BYRD: That would be --

MEMBER SHACK: -- for lap for that size bar?

MR. BYRD: That would be larger than the current code. I think Jon Hook could tell me what the current code is. I think that's significantly larger.

MR. HOOK: Right, the -- it's either consistent with or more conservative than the existing code. And on the original AE, Bechtel was conservative when they came up with a 120-inch splice up on top.

MEMBER SHACK: Thank you, John.

MEMBER STETKAR: Before you switch, I don't do conversions from Richter to acceleration all that well, as can nobody. Six to 6.5 Richter, are you saying it's about --

MR. BYRD: I can give you the acceleration. That's 0.08 g. That's maximum probable. Maximum possible is 0.15.

MEMBER STETKAR: 0.15?

MR. BYRD: 0.15. That's correct.

MEMBER STETKAR: Thank you.

MR. BYRD: Okay. Going to the next slide, please. So we understood that with these cracks in the rebar that would be a concern with the bond between the rebar and the margin. We also recognize with the very tight cracks, there probably was a considerable amount of bond strength, but we didn't have a method to quantify it. We didn't have any specific testing that could tell us what bond strength was left. So therefore we -- in our analysis we performed prior to restarting we conservatively treated all of the rebar in the shoulder areas, in affected areas of the top 20 feet, and in these main steamline penetration areas as non-existent in the analysis. So we performed calculations to prove they provide bounding evaluation.

And if you go onto the next page, the result of that was that the -- even with these very conservative assumptions of the lack of -- or not effectiveness of the rebar in these regions, we didn't meet our requirements with traditional margins of safety. So that was the process we used to demonstrate that the shield building was capable of performing its safety functions.

If we can go to the next slide, please --

CHAIRMAN SIEBER: Now, its only safety function is to provide shielding as opposed to containing the pressure of the accident?

MR. BYRD: That is correct. It is not designed to contain the pressure of the accident. It does provided, as I mentioned before in the functions, we do have the annulus base which we can take a suction on with our ventilation, so it does provide a function of being able to provide that controlled release of the annulus.

CHAIRMAN SIEBER: And so as part of the original design you have the ability to have a controlled release of gaseous material in the annular space between the containment pressure vessel and the containment shield building?

MR. BYRD: Correct.

CHAIRMAN SIEBER: Okay.

MEMBER STETKAR: The safety analysis accounts for that, the availability of that interstitial ventilation filtering system, or not?

MR. BYRD: I would have to ask Dennis Blakely to respond to that question. He's our analysis supervisor.

MR. BLAKELY: Dennis Blakely, engineering analysis supervisor. The LOCA analysis does credit the ability to take suction on the annular space through our emergency ventilation system. It filters the release prior to going to the environment.

MEMBER STETKAR: Thank you. Some do. Some don't. That's why I asked. Thank you.

CHAIRMAN SIEBER: Well, the purpose of my question is to establish clearly just what the function of the building is, the structure is. And that -- because it's different than other types of large dry containers.

MR. BYRD: Okay. Next I'm going to talk about the root cause. And while we were in the process of doing the investigation that I just described, we had established an independent root cause team which was evaluating the root cause. And so what I'm going to talk about here, I'll talk a little bit about the team, the establishment of the team, talk about how we put together our failure- modes analysis, discuss a little bit of the testing we did, some of the concrete testing analysis, and then explain what our root cause was.

So the next slide, please. So early in the process we did get Performance Improvement International involved. And I'm sure that you're -- most of you are familiar with Performance Improvement International. They are very experienced. They've performed over 500 root causes. But what was particularly beneficial for us is they had done the root cause on Crystal River, and as a result of doing that root cause on the containment, they had developed expertise in analytical methods for concrete, and they also had a lot of expertise in concrete testing. So that was very beneficial to us in getting our root cause moving in a fairly expeditious manner.

We also supplemented the Performance Improvement International with other industry experts and we used our on FENOC engineering as well. And we did follow our own FENOC root cause process.

CHAIRMAN SIEBER: Crystal River is a post-tension concrete vessel --

MR. BYRD: That's correct.

CHAIRMAN SIEBER: -- which is substantially different in structural design from the Davis-Besse containment building. And so the root cause at Crystal River is not applicable here.

MR. BYRD: The root cause was completely different --

CHAIRMAN SIEBER: Right.

MR. BYRD: -- I would agree, at Crystal River. What was helpful to us however was having --

CHAIRMAN SIEBER: The analytical techniques.

MR. BYRD: -- the analytical techniques, the experience in testing concrete, some of that other -- that was what helped with us.

CHAIRMAN SIEBER: Now as part of your root cause analysis did you look into any aspect of the composition of the concrete that was used as it came from the batch plant and, for example, reactions within the concrete such as was found at Seabrook?

MR. BYRD: Yes, we looked at that extensively. In fact, Mr. Hook is going to be able to explain that you.

MR. HOOK: Right, I think you're referring to alkali-silica reaction.

CHAIRMAN SIEBER: That's right.

MR. HOOK: Right, so as part of our root cause; and Ken will get to that in a little bit though, we took over -- we took 90 core bores. Thirty-six of those core bores we sent out to independent laboratories. We used several laboratories to do that. And that's one of the things they specifically looked for, is chemical reaction. They did petrograph examination and all of those tests came back as being negative, meaning we had no indications of alkali-silica reaction.

And so we also -- all the aggregate for the shield building came from the same quarry as we used for all the other concrete on the site. So we have no indications of chemical reactions. So we have high confidence that ASR is not an issue at Davis-Besse.

CHAIRMAN SIEBER: Okay. Now when Davis-Besse was constructed, I presume you had your own concrete batch plant?

MR. HOOK: Right, we had a batch plant on site. That's right.

CHAIRMAN SIEBER: Yes, you don't look old enough to remember that, but I do.

MR. HOOK: I have seen pictures. But, right. In fact, we had our own batch plant on site, a central batch plant. And so all the concrete on site was batched from that batch plant.

CHAIRMAN SIEBER: And you poured samples daily --

MR. HOOK: Absolutely.

CHAIRMAN SIEBER: -- from the batch plant and typically from each truckload as it was delivered from the batch plant to the building construction site, is that correct?

MR. HOOK: That's right. And as part of our root cause investigation, we do look at the batch records. We looked at QC reports. The sequencing of the pours. The shield building was poured as slip form. So we looked at all those construction records. We looked at the 28-day concrete strengths that we did, and the 90-day strengths. And they -- our design is based on a 4,000-psi concrete, and the average 28-day strength was about 5,800. So we had high concrete strength.

CHAIRMAN SIEBER: Yes, typically you can meet the strength requirements. On the other hand, typically the data that you get from the blocks that you pour for testing do not contain chemistry data. Do you have any chemistry data that corresponds to the blocks that were tested for your concrete mixture as it was put in place with the removable --

MR. HOOK: Right, so part of the mix design process -- so we did evaluate the chemical and the -- well, the coarse aggregate and the fine aggregate met the ASTM requirements at the time.

CHAIRMAN SIEBER: Okay. And the water content and the water purity was off the -- you have records of those?

MR. HOOK: Right. It's all potable water, correct.

CHAIRMAN SIEBER: And you verified that those met the ACI standards at the time?

MR. HOOK: They met the ACI and the American Society for Testing Materials standards. That is correct. And as spelled out in our specifications for that, correct.

CHAIRMAN SIEBER: Okay. Thank you.

MR. BYRD: Okay. Let's go to the next slide, please. So this slide shows the fault tree of failure modes that we used to investigate the condition. So we had 45 failure modes and we grouped these into three different categories. Those were design issues, construction and fabrication issues, and then operational phase issues. So each of these issues was worked through methodically and we either eliminated them or determined we needed to have additional evaluation. So what you can see from this slide, the ones that are circled in blue, those are the one that were eliminated. And the one which are reddish or orange, those were the issues that we performed additional investigation on.

The next slide, please. So in order to do the root cause we did extensive testing of the concrete. We sent 36 core bores for testing at six different locations. They subjected it to a number of different tests. Tested for concrete properties, tensile strength, compressive strength. They looked at thermal properties of the concrete. And we also looked at some of the issues which we were -- if there were chemical attack. We looked for issues of micro-cracking. So quite a bit of work was done. The tests came back indicating, however, that the concrete quality was good, conformed to our mix design, and the compressive and tensile strength exceeded the minimum design requirements.

So I'm not going to go talk about each of these concrete tests we did, but there was there tests I want to talk about that were maybe somewhat revealing with regards to the root cause that we ended up coming to.

So the first one; if go to the next slide, was the manner in which the concrete fractured and through the aggregate. And the picture you see here is a piece of the concrete that we picked up in the area of where we were doing the hydro-demolition. And as you can see the surface of the crack is smooth. It actually sheared through the coarse aggregate. And that told us several things. We also saw this in the core bore samples we took, which --

MEMBER ARMIJO: This is -- the crack's face is in a vertical --

MR. BYRD: That's correct. The vertical is the crack face. And you can see it goes through the aggregate. It's very, very smooth. It told us several things. It told us first of all that there was a -- a considerable force was required to -- for that crack. Our aggregate is not -- it is strong. We don't have a problem with the aggregate. It told us we had good bond between the aggregate and the paste. What that told us, that this crack occurred in mature concrete. This obviously wasn't something that occurred early in the process before the concrete had time to gain its strength.

Next slide, please. Another test that was revealing is the inspection for micro-cracking. And the slide here is a cross-section of the concrete sample that was used to do an inspection for micro-cracking. So we found no evidence of micro-cracking in the areas near the laminar cracks. There was no sign of a cyclic loading mechanism or a freeze-thaw mechanism. And what this suggested to us, there was no indication of a fatigue or an age-related event.

Now to be clear, there was in some of the reports micro-cracking identified. That micro-cracking was near the surface. So surface cracking was identified. But in the vicinity of these laminar cracks, which was really the area of interest, we did not identify micro-cracking.

MEMBER ARMIJO: I just want to make sure. Were these cracks just -- was it a one-planar crack, or were there a number of just parallel cracks along this?

MR. BYRD: It would be -- there was probably -- I wouldn't say it was a -- it was generally on a plane in the rebar, but I wouldn't say there was just one crack. It was -- in some places --

MEMBER ARMIJO: So it's a zone where there might be --

MR. BYRD: Yes, it might. And it might meander around a bit. And then we would -- what we concluded, the cracking was generally in a plane around the inner -- outer rebar mat. But not to say that we wouldn't have --

MEMBER ARMIJO: Yes, something --

MR. BYRD: Yes, like you're describing it.

CHAIRMAN SIEBER: But it was really circumferentially as opposed to radially?

MR. BYRD: I'm sorry, sir?

CHAIRMAN SIEBER: It was oriented -- the cracks were oriented circumferentially rather than radially.

MR. BYRD: That's correct. That is correct.

Okay. The next slide, please. The final test I want to talk about is carbonation. And actually we had a lot of evidence without actually testing the concrete that carbonation was not the issue. And it becomes -- first of all, it was the particular location where we found the cracks. The cracks were -- as I mentioned before, they were primarily in the outer -- well, pretty much all in the outer rebar mat and mostly in the shoulder region. The shoulder region is an area where we actually have quite a bit of concrete cover. On the thick side, you have almost 20 inches of concrete cover. So that would suggest that carbonation was not an issue.

Additionally, we had no evidence of degradation of the rebar. We did inspect rebar that we removed in the area where we had the construction opening. And we had no indication, as I mentioned before, of surface spalling in these areas that were cracked. All that suggested that carbonation was not an issue.

However, I wanted to discuss this testing because carbonation was discussed a lot and it was -- and it's an aging mechanism. So what you can see here on this picture, there's a dye. And the areas that are pink are the non-carbonated areas. But the surface of this concrete sample which was exposed to the atmosphere you can see is the carbonated area. We found that in general, average it was about a third of an inch we'd get carbonation. Maximum, about a half of an inch. And we have the three-inch cover over the outer rebar mat, so that was sufficient for a -- of course this is in -- in 40 years we had this much carbonation, so this should not be an issue for the duration of the plant through its extended life.

MEMBER ARMIJO: I may be the only guy in the room that doesn't know what carbonation is, but could you tell me what that is?

MR. BYRD: Sure. Carbonation is a process where carbon dioxide in the air reacts with calcium hydroxide, the lime in the concrete, and that forms calcium carbonate. And it's not really a problem in concrete. Actually it makes the concrete, if anything, a little stronger. But the issue is is concrete normally has a pH which tends to inhibit corrosion in the areas where you have rebar. And carbonation will actually affect the pH of the concrete. So if you were to -- normally, if you were -- carbonation damage, what would happen is you'd get carbonation that would go deep enough so it gets to the point where you have your rebar mat. At that point you're affecting the pH. Then you'd get corrosion of your rebar. Then you'd see the rebar would start expanding. You'd see spalling and cracking in the concrete. I mean, that's typically what you would you see for carbonation damage.

MEMBER ARMIJO: All right.

MR. BYRD: So as I mentioned before, we didn't see any spalling, any damage to the rebar.

Additionally, we've got maximum half an inch with three-inch cover, so it's really not a concern.

MEMBER ARMIJO: Okay. Great.

MR. BYRD: Okay. Next slide, please. So to summarize what we saw with our concrete, so the crack passed through coarse aggregate and that told us we had a strong bond between the paste and the aggregate and the crack occurred in mature concrete. It also told us we had to have a pretty large force to initiate that crack.

CHAIRMAN SIEBER: So you had evidence that the aggregate itself had cracked and split?

MR. BYRD: Oh, absolutely. The aggregate -- the crack went right through the aggregate. That shear picture you saw, you know, if you see it close, you would see the aggregate was actually sheared straight through. And as I said before, our aggregate is local limestone. It's reasonably hard and it's -- so it was a considerable force.

So we also identified no micro-cracks in the vicinity's laminar crackings that would indicate freeze-thaw or cyclic event.

Chemical properties, as I mentioned, we did carbonation. And as Mr. Hook mentioned, we also looked for alkali-aggregate reaction. We looked for sulfate attack and any kind of acid damage. We didn't see any indication of chemical attack. So based on that we were able to rule out concrete as an initiating or a contributing cause. We also gained some additional information. We pretty much told us this appeared to be an event that had occurred which had caused this crack, rather than some kind of a cyclic or a fatigue-type of a mechanism.

CHAIRMAN SIEBER: Okay. And Lake Erie is a freshwater lake, right?

MR. BYRD: Lake Erie is a freshwater lake. That is correct.

CHAIRMAN SIEBER: And can we conclude that atmospheric conditions do not contain any unusual chemistry that you might find near a seashore? For example, industrial plants sometimes emit things that can deposit on concrete and changes its physical and chemical characteristics. You have no industrial plants close to Davis-Besse?

MR. BYRD: Where we are -- as I mentioned, we're in a wildlife refuge, so there's really no -- there's no industrial plants. They would -- you would have to be 30 miles away to Toledo, or it's probably 50 miles or 60 miles to Cleveland. So we're not in an area that's --

CHAIRMAN SIEBER: My recollection is that the closest coal-fired power plant is about 30 miles away, 35 miles away.

MR. BYRD: About that, that's correct.

CHAIRMAN SIEBER: Okay. And I don't recall any others along Lake Erie until you get to the area where Perry is.

MR. BYRD: That's correct.

CHAIRMAN SIEBER: Okay. Thank you.

MR. BYRD: Okay. Next slide, please. So the next thing we looked at was shield building configuration. And actually looking at the configuration of the cracks did provide some pretty valuable insight. And I mentioned before, cracking is predominantly located in the shoulder areas in the top 20 feet and in the main steamline penetration block-outs, and it was concentrated on the southern exposures. So as we looked at the crack locations and looked at the details which I previously described to you of the shield building, several things became fairly apparent. One is that the shoulder areas are regions of discontinuity. In other words, we have these shoulders built on. And there was -- and was pointed out, there's limited radial reinforcing steel in those areas. So based on that we decided that was an area that we'd want to investigate further.

Another thing we noticed is the top 20 feet of our shield building has more horizontal reinforcement. The horizontal reinforcement, which is this No. 11 rebar, is every since 6-inch spacing until you get to the top 20 feet and then it goes to -- I'm sorry, it's 12-inch spacing, thank you, until we get to the top 20 feet in which it goes to 6-inch spacing.

And actually we noticed in some of our impulse response testing the really good correlation we got. Up above into the higher-density rebar we start seeing laminar cracking outside of the shoulders. So we decided that obviously the density of the rebar was something that would be -- warrant further investigation.

And we also were aware that around the main steamline penetration block-outs there's another area where we have dense rebar around the block-outs. Because the cracking we saw around the block-outs, within the block-out itself there was no cracking at all. In fact, we could actually use an impulse response. We could trace the block-out itself. But we find the cracking was actually occurring around the edge of the block-out. We could actually see the corners of the block-out in the impulse response testing, which was quite remarkable. So that told us there was again -- appeared to be a correlation between rebar density and the cracking we were observing. And then finally there was clearly this south versus north orientation. That was something else we needed to do some further investigation of.

MEMBER ARMIJO: And you'll get into that when you get to your root cause --

MR. BYRD: Yes, I will.

MEMBER ARMIJO: -- to show why south?

MR. BYRD: I will.

MEMBER ARMIJO: Why top 20?

MR. BYRD: Absolutely.

CHAIRMAN SIEBER: Rebar density in a containment design like Davis-Besse is far less than those where the containment building is actually a pressure barrier. Is that not correct?

MR. BYRD: That would be correct.

Okay. So we -- going onto the next slide, please. So we did a number of detailed analysis to better understand -- and again, I mentioned the shoulder areas appeared to be a discontinuity and something to further investigate. So we did a number of very detailed analysis to understand how these shoulder areas responded to various loading conditions. And the first area that we really looked at seriously was thermal conditions. Looked at -- and to do this we evaluated 32 different thermal conditions. In other words, winter, summer, various different combinations of inside and outside temperatures. Did screening on 32 of those. And then we did a more detailed evaluation on the most -- the top six events. And then for those events we combined the thermal stresses with stresses caused by dead weight and wind.

And the results of all of this though was that the radial stresses -- well, first of all, the radial stress was maximized in summer conditions, hot summer conditions. But when we combined the thermal stress with the dead weight and wind loads, we didn't come up with stresses that were nearly sufficient to create the kind of cracking we saw. The maximum was about 300 pound per square inch. That's about half of the -- what would be required to create the cracking.

So the other thing we looked at was unusual events that have occurred. And we did have a tornado. It was a category 2 tornado which had been in the vicinity of the plant; I don't believe it actually struck the shield building, and that was in 1998. We did evaluate wind loads. Wind loads based on this model were not even -- very insignificant for those kind of wind conditions. So we'd eliminated thermal conditions, which actually when we first looked at this was very suggestive on the south side, and eliminated the tornado, determined those weren't sufficient for cracking.

Next slide, please. So what we had is we understood that we had an event, as I said before, from the concrete. This was a event-driven event. So at this point we did research into additional industry experience to determine if there was other similar conditions.

So if we'd go to the next slide, I'll talk a little bit about the operating experience we identified. Okay. As I mentioned before, for operating experience we had Performance Improvement who had performed the root cause on the Crystal River laminar cracking. However, it was also pointed out here previously, the Crystal River really didn't apply to Davis-Besse. They have a post-tension containment. We have a freestanding containment. The conditions, they had some concrete quality issues. And as I mentioned before, we didn't appear to have any concrete quality issues. So really there was not any correlation we could get between Crystal River and Davis-Besse.

However we did find some operating

experience from the Ontario Ministry of the Environment. They'd done a study of above-ground water tanks up in Ontario and the conditions that they'd found was that the water tanks -- in the winter you would have the -- the water would penetrate the concrete on the inside of the tank. And then when you got very cold weather, the moisture in the concrete on the inside was expanding. The cold weather was also causing the exterior to contract and that was creating high radial stresses in these tanks and actually was causing laminar cracking in the tanks. So that suggested to us another possible failure, which could be moisture penetration and freezing.

Now obviously Davis-Besse is not a water tank, and so we were looking at it really from the other way around, having water penetrating from the outside and then having very cold temperatures. So we considered some potential for water penetration, and it appeared the most probable cause would be high wind and rain that could cause water penetration.

So going to the next slide, please. So we investigated potential conditions where we could have had water penetration in the shield building followed by extreme cold. And the most significant environmental condition was in the winter of 1978, which also was the worst environmental condition in recorded Ohio history in terms of moisture, temperature, wind and duration.

If you'd go to the next slide. So on January 25th through 27th of 1978, it rained several days and we had -- actually the temperatures were in the 40s during that period. There were high sustained winds. There were gusts of over 100 miles an hour in the vicinity of the plant. We had very low temperatures. Temperatures then dropped down to approximately 0 degrees Fahrenheit. We had sustained low-temperature conditions for several days. So those really are the conditions that occurred in '78.

So if you go to the next slide. So the scenario for the event that we proposed was if we had heavy rains preceding a blizzard and that caused moisture to penetrate the exterior surface of the concrete, and we had a drop in temperature to well below freezing and that would freeze -- and strong winds, that would freeze the outer concrete, the moisture in the outer concrete. And then with no radial reinforcing in the shoulder areas, the radial stresses that we were developing in the building were exceeding the capability of the concrete, tensile capability of the concrete.

All right. So next slide, please. So in order to demonstrate that this was in fact a credible theory, we did develop a computer model of the shield building to evaluate the condition. Used thermal properties from the concrete which we used from some of these core tests that we'd performed. There were laboratory tests performed which demonstrated that moisture infiltration could be up to four inches for the particular wind duration and strength that we had during this storm. What the model did show is that our maximum radial stress is approximately 550 pounds per square inch. And as you can see from this picture, the radial stress was concentrated precisely in the area where we saw -- primarily we saw the cracking. So again, this was consistent with what we saw in the root cause.

We also -- I just want to make a point here. We did look at other events other than the storm of 1978. We did look at some of the other significant storms we've had and we didn't find any other storm. We actually evaluated -- I think the second worst was in 1977. We didn't find another storm that had the right combination of rain, cold and duration to create this event. So that's why we believe this occurred in 1978 and not at another period of time.

Okay. So that explained -- at least this created for us in our minds a plausible explanation for the cracking we saw in the flute shoulders. We still also had the other issue with the cracking in the high-density rebar areas. So here we did a computer model to do a sensitivity analysis of cracking in high-density rebar. And this evaluation demonstrated that the laminar cracks are more likely to occur in regions where we have closely-spaced rebar. We did an analysis with 12-inch versus 6-inch rebar. And so that established that the rebar spacing was a probable contributing factor. And what we believe occurred was that the cracking would have been initiated in the shoulders and then propagated into some of these areas where it's more -- where it's more likely in the high-density rebar areas. And we think that occurred both in the shoulders and in the main steamline penetration block-out areas.

Okay. To summarize what we got from the analysis. So to summarize, the normal temperature -- when I say "normal," the extreme temperature conditions weren't sufficient to create radial stresses that could cause cracking. We did not find sufficient -- any -- high-wind was not sufficient. We did find though that this moisture freezing could cause stresses in the shoulder areas that could result in the cracking.

So that appeared to be a plausible event that occurred. We also found that the closely-spaced reinforcing steel was a -- could be a contributor to the laminar cracking.

And then finally, the observed cracking. And this is very important what we actually saw, and I'll show it in a few slides from now, the picture of our impulse response testing. What we found in the cracking very much coincides with the areas of high stress. The cracking was in the flute shoulders, in the areas of high-density rebar, and it was also concentrated on the southern exposure, which would have been the direction we would have had the storm coming from and the moisture penetration. So again, it had good correlation with this theory with the actual facts we'd obtained from investigating the shield building.

MEMBER ARMIJO: That southern exposure argument sure doesn't really tell me much, because that's a big storm. The whole plant's affected. Moisture's -- I'm sure it didn't rain just on one side of the building.

MR. BYRD: No, it rained, but the southern exposure -- the issue is the direction of the wind, because the wind was an important -- would have been an important in providing the force for the moisture penetration in the shield building. And as you can see from the picture, it isn't that there's not cracking on the northern side. It's just there is more extensive cracking on the southern side of the building.

So finally, to go to our root cause, really there was many things, or several things acting together that caused cracking to occur. So we had the discontinuity on the shoulders with the lack of radial reinforcing rebar. We had the areas of high-density rebar. Then we had the particular storm with high moisture, severe winds and very low temperatures. However, for us to establish -- for our process and root cause it had to be something that we could eliminate to prevent recurrence. So we identified the root cause for our -- to be a lack of water sealant on the exterior of the building.

If you'd go to the next slide, please.

DR. BARTON: I've got a question on it.

MR. BYRD: Yes?

DR. BARTON: So you're going to seal the building?

MR. BYRD: We are in the process of doing that now. That's correct.

DR. BARTON: The question I've got is how do you know that there's no water trapped inside this concrete before you're sealing it?

MR. BYRD: Well, there probably is some. We have taken samples very recently. Mr. Hook, can you talk about the samples we took of the concrete?

MR. HOOK: Right, so there is some moisture in the concrete always. It's not like bone, bone dry. But part of the root cause investigation and the sensitivity analysis that we needed to have, we need to have high moisture content in the concrete for this -- for the freezing and expansion to occur. That was in the area of 90-plus percent of concrete. So concrete breathes and normally the concrete that's out there is in the range of 40 to 60 percent. So those moisture levels are well below the threshold that's needed to cause any expansion. So when we paint the building, whatever moisture is there, it has no effect at all. And also keep in mind though the inside of the wall is not painted. So that's also an opportunity for the concrete to breathe on the inside in the annulus area.

DR. BARTON: So you've looked at -- even though you've got some moisture in there, you've looked at weather conditions, severe weather conditions, and you're convinced that that won't cause cracking to expand?

MR. BYRD: That's correct. And then we're following the manufacturer's instructions on how to paint the concrete. And so you need to have certain humidity and temperature requirements. And obviously you can't paint the concrete when it's wet. So we are following all of those requirements as well.

DR. BARTON: Thank you.

CHAIRMAN SIEBER: As part of your overall investigation, I notice the slide which shows the map and the path of the storm of January 1978 is pretty extensive. It covers the entire state of Michigan from Central Illinois to Gary, Indiana and about half of the State of Indiana and reaches to Toledo and appears to be on the edge of the excessive area appears to be where the Davis-Besse appears. Did anyone look at other news stories or event reporting from that storm to determine whether other structures were damaged by any kind of a phenomenon that you believe occurred here at the Davis-Besse plant?

MR. BYRD: Well, if your question is did we have -- did we find any other evidence of laminar cracking caused by moisture penetration, the answer would be no. The only -- and we looked pretty extensively through operating experience and what we found was this Ontario Ministry -- the information we found on the water tanks was actually online. So we did not find evidence specifically of cracking that was attributed to this storm.

CHAIRMAN SIEBER: Well, most industries don't have a reporting structure similar to that --

MR. BYRD: And we understand that and that's why we looked extensively. We didn't find the Ontario Ministry of Hydro through the normal reporting structures. Obviously it would be difficult, and as I mentioned in our root cause, there were some unique characteristics of Davis-Besse; the flute design and so forth, that along with this storm contributed to the laminar cracking. So -- and but there was certainly a lot of news. The storm of 1978 was a very significant event in the Midwest. So obviously at the time there was a lot of news coverage, but I don't believe there was any trouble with laminar cracking.

CHAIRMAN SIEBER: All right. Thank you.

MEMBER ARMIJO: How does your root cause explain the absence of cracking at the surface? Visible cracking. In other words, all the cracking is inside in this -- between the shoulder and the -- you know, the outer steel. But the cracks don't penetrate to let's say the notch.

MR. BYRD: No, and the reason --

MEMBER ARMIJO: And they -- you know, so

what's the explanation for that?

MR. BYRD: If we could go back to the slide that shows the rebar design of the shoulder. I'm not sure which number it is.

CHAIRMAN SIEBER: Way back.

MR. BYRD: It's pretty far back. I can explain that.

MEMBER ARMIJO: Twenty-one?

MR. BYRD: That's correct.

MEMBER ARMIJO: Where the hooks are?

MR. BYRD: Yes, the explanation is, as I mentioned, the crack occurred and it was stopped before it got to those -- that inner -- or the radial reinforcing rebar on the inside. And actually on some of these shoulders we drilled on the shoulder four core bores on the same -- at the same horizontal plane. And if you could point with your mouse, we did one core bore on the shoulder on the outside of the rebar there.

MEMBER ARMIJO: Yes.

MR. BYRD: And one on the insider. It shows we did one right here. We managed to get a core bore in there. And we do the core bore on the other side. Well, I'm sorry, we did one core bore up adjacent to the rebar here and we found we did not have cracking up beside the rebar. Then we went over. We found cracking. So the crack was actually stopped by the rebar. Then on the other side we drilled the same thing. We drilled a core boring here and we found no cracking right adjacent to the radial reinforcement. So we were able to demonstrate with our core bores that actually that radial reinforcement was in areas out -- like it's up on the 20 feet. The cracking would be restricted between that area. Then on the top 20 feet we found that we did have some cracking that would go outside through this area. But it didn't go beyond these hooks on the inside.

MEMBER ARMIJO: But you would have expected that the water penetration would be greater in near the surface?

MR. BYRD: That's correct.

MEMBER ARMIJO: And in that corner notch where you have a stress concentration, plenty of access to water. Yet it didn't crack there.

MR. BYRD: It didn't crack there except on the -- in the -- some areas in the top 20 feet we found cracking. But again, that cracking was along the -- in this rebar mat and again there's still a cover of concrete on that as well. So it was actually in the -- it was always covered with concrete on the cracking. And that's actually -- you know, we did not -- in the carbonation samples we took we didn't find extensive carbonation in the crack regions either. So that would indicate that these cracks had been -- not been exposed to the air.

MR. ALLEN: What's unique about the design here is that if the shoulders were not present, even with the moisture, the wind, we would have had no cracking.

MEMBER ARMIJO: Oh, I agree with you there.

MR. ALLEN: But discontinuity Ken talked about, rather than a right circular cylinder which can expand and contract uniformly, it's sitting there essentially shrugging with those shoulders as it's moving. And you have to have that stress concentration plus the moisture and freezing for it to be an issue. And then it propagates.

MEMBER ARMIJO: You know, the argument -- I'm just -- I'm skeptical about the moisture and freezing part of your root cause. The thermal analysis surprised me, that that didn't provide sufficient stress. Just -- it's a -- looks like a design flaw. Not the shield building integrity, but the flute attachments. You know, I think -- and if it isn't related to moisture, then painting isn't going to do any good.

MR. ALLEN: Well, first of all, maybe Dr. Chiu could discuss that a little bit more from performance improvement and what we did for evaluating thermal versus moisture.

DR. CHIU: What was the question? Can you repeat that question?

MEMBER ARMIJO: Yes, you know, why isn't this -- why do you need the moisture from one event, one storm caused all this damage as opposed to it just being a design flaw and the thermal stresses over time just simply created cracks without the need for any kind of moisture?

DR. CHIU: I think the reason for that is because the -- as you look at a corner, we have water penetrated on both directions, goes through the crystallization of concrete, would generate a lot more expansion than thermal. It's almost a factor of three. So with the water crystallization-induced expansion, it's lot more severe than thermal. You can imagine if the thermal is -- in Arizona we have so much hot weather, 120 degree Fahrenheit, the fluting didn't report an crack. And we just finish another analysis at another power plant in the south that has flute. But you just look at thermal, it not going to have any laminar crack.

So you really need both, very high thermal expansion -- I mean, crystallization-induced expansion.

MEMBER ARMIJO: Okay. Well, near the surface I would expect more water, more crystallization so that cracks should penetrate to the surface at those notches and elsewhere, but in every case, at least the way it's been described, the cracking is varied inside. It doesn't penetrate to the surface. So I'm just -- can't understand.

MEMBER SHACK: It needs constraint. It's free to expand at the outer surface.

MEMBER ARMIJO: Right.

MEMBER SHACK: You know, so he has to build up constraint before he can build up some force. So I can understand that you wouldn't see cracking at the surface. I'd have to be somewhere underneath where I have enough restraint so I can build up a radial stress. You know, in plane it's going to be compressive as it expands. And at the outer surface it's going to be free to expand. Somewhere in the middle, things are going to go wrong.

But I was -- My question is do you actually -- did you do measurements of the expansion of water-saturated concrete as it freezes, or is this some model, or you just put in enough expansion to get whatever you needed?

DR. CHIU: We did a test. We did a test. As you know, that only this type of concrete -- certain type of concrete, when the water diffuse into concrete, it can cause the crystallization-induced --

MEMBER SHACK: Yes, when you say "cause crystallization," are we talking about water freezing and expanding, or we're talking about a change in the concrete property?

DR. CHIU: Water.

MEMBER SHACK: Water?

DR. CHIU: Water.

MEMBER SHACK: Okay. So the --

DR. CHIU: And the critical point is void fraction. For typical concrete, like household, your house. The void fraction is very, very high, probably four percent, five percent. When water diffuse into the concrete, it's sort of goes away. You don't have that expansion. But when the nuclear grade, we have very, very tight void. We control the quality very well. The void fraction is like three percent, two percent. Then we have water diffuse into concrete. You would expect.

So what we did is we did a test at the University of Colorado by Dr. Xi and reproduced this

-- I call it crystallization-induced expansion. And we really reproduced that. As you drop the temperature, the thermal expansion coefficient, you will -- the concrete will shrink. By the certain temperature and certain void fraction of that concrete the -- absolutely the thermal coefficient will turn around. When that turn around, that is the problem.

MEMBER ARMIJO: Well, I think we'd like -- I'd like to see that test result and the analysis. Because, you know, what you're saying may be fine, but it just seems that the denser concrete, smaller void fractions, the penetration rate of the water would be slowed down just doesn't seem to hang together. But maybe if I read the report, I'll understand it better.

MEMBER SHACK: Well, did you actually try tests with different void fractions of concrete?

DR. CHIU: No, we only test this concrete.

MEMBER SHACK: This concrete?

DR. CHIU: But in the Canadian paper they do alluded to that was their test with high-void fraction concrete. They don't have that denominator.

MEMBER ARMIJO: Okay.

DR. CHIU: Only in certain concrete.

MEMBER ARMIJO: Maybe ask, Dr. Chiu, is it your conclusion that all of this cracking happened during that storm?

MR. BYRD: That was the conclusion of our root cause. That is correct.

MEMBER ARMIJO: Okay.

MR. BYRD: This was an event we believe that occurred during the storm.

MEMBER ARMIJO: And it wasn't detectable because it didn't -- never penetrated to the outside?

MR. BYRD: It was -- it never penetrated to the outside and it --

MEMBER ARMIJO: That's the thing that bothers me the most.

MR. BYRD: And it did not -- in our previous construction opening we had cut in 2002 or 2003, we did not cut that -- because we actually cut that construction open entirely within the confines of our -- the original construction opening, and that is not an area where we had any evidence of this kind of cracking.

And to further comment on your -- because what your insight was, when I first this I was completely convinced this was thermal.

MEMBER ARMIJO: I'm still convinced, but it's --

MR. BYRD: Well, because it was on the south side and I saw it there and that was what I thought.

You know, I'll have to admit it took awhile for me to come around to this, but the very strong -- actually, I mentioned before on the -- this is no evidence of any kind of a cyclic or a fatigue-type of an event. So this occurred as one event. And that's based on actually the concrete. So not only do we have the analysis that's aligned with what we observed with the concrete -- so I just want to point that out that it appeared to be an event with enough force to have created this, and which would have been a pretty significant amount of force.

MEMBER ARMIJO: Okay. Well, I still would like to get a copy of that report, if it's available.

CHAIRMAN SIEBER: Yes, there is a root cause report.

MEMBER ARMIJO: Yes. Yes, particularly that test that Dr. Chiu --

MEMBER STETKAR: You're looking for the University of Colorado test?

MEMBER ARMIJO: Yes.

CHAIRMAN SIEBER: Yes, that's different. That's not in the report.

MR. BYRD: Okay. If I could move on, unless there's another question. I believe we're on slide No. 50.

Okay. So we had identified the root cause to be a lack of concrete sealer. And for that particular root cause there was really one practical corrective action that we could take to prevent recurrence, and that was to coat the exterior of the building. And as I mentioned before, that coating is in progress right now. In fact, the photograph we have here shows some of the recent coating activities. We're at this point approximately 75 percent complete with our project to coat the entire shield building.

CHAIRMAN SIEBER: Yes, what's the coating material?

MR. BYRD: So the walls are going to be a latex acrylic primer and a styrene acrylic top coat. And the dome is a polyurethane.

CHAIRMAN SIEBER: Okay. So you're painting it?

MR. BYRD: That's correct.

CHAIRMAN SIEBER: Okay.

MR. BYRD: Next slide, please. So we also identified several additional corrective actions as a result of our root cause. And those corrective actions included completing the impulse response examinations of the shield building wall. They included performing impulse response mapping of another structure which was in this case the auxiliary building to confirm the assumptions of the analysis. We did also developed and implemented a test program to establish the capability of the bond between the rebar and the concrete in the area of the laminar cracks, and we developed a long-term monitoring program. So I'll briefly describe each of these corrective actions and what we're doing in these areas.

MEMBER SHACK: Just a quick question on the analysis again. You said you gave up on all the regions of cracking on the lap strength.

MR. BYRD: That's correct.

MEMBER SHACK: Now, I mean, you did a full -- I mean, we keep seeing pictures of membrane-kind of regions here. Do you -- but you did a full stress analysis including the bending regions. I mean, that's why I have dense rebar at the top is I've got flexural strength up there.

MR. BYRD: That's correct.

MEMBER SHACK: And you do that -- even with the zero lap strength, you can still meet all your design requirements?

MR. BYRD: That is correct. That is correct. The pictures I've been showing here were done as part of the root cause, and that was done independently of the analysis done for the -- to determine flexural integrity.

Okay. So I'll go to the next slide, which will be No. 52. So we did complete the impulse response testing on the shield building this summer. So we did all accessible areas of the shield building wall, and that was over 60,000 individual points. So you can see the work going in progress with a couple of scaffolds up on the building. And actually in this picture you can see our most recent construction opening directly under that one scaffold.

So what the -- going onto the next slide, please. What this impulse response testing did, it validated the original assumption that laminar cracking was generally confined to the shoulder areas, top of the building and regions of the main steamline, and it was more concentrated on the southern part of the building.

We also validated this by doing impulse response testing on an independent site structure and we selected a portion of the auxiliary building. And the portion we did had some of the susceptible characteristics. It was -- actually we did an area above a large opening. It was above the train bay door on the auxiliary building on the southwest side of the building. However, the auxiliary building has -- it has a coating -- it has had a coating put on it for the life of the building. And we did not detect laminar cracking on the auxiliary building.

So the next slide, finally we get to this impulse response mapping -- testing map that I've been talking about. And there are a couple areas I want to point out. First of all, the magenta areas on this are areas of the building which are areas of higher mobility, and that would suggest that we have laminar cracking in those regions. And you can see that the laminar cracking is generally confined to the shoulders. YOU can see how it's going down on the shoulders. You also see it spilling out into the top 20 feet. And if you look on the lower left-hand side, you can see the azimuth down there. You see zero azimuth. That's north. And so you notice on the north side we have relatively limited cracking on the north side of the building as opposed to what we see on the south side of the building. So again, the -- what we had identified here is consistent with what we saw during the -- consistent with what we developed in the root cause.

Okay. The next slide, please. So as I'd previously described in our analysis we did, we considered the reinforcement to be non-existent in regions of laminar cracking. And although we're aware that there was probably a considerable amount of concrete to bond strength in those areas, so we did develop testing at two universities, and these were developed by professors who are experts and members of the American Concrete Institute. The picture you see here is a test that's ongoing at -- that was ongoing at one of the universities. That's about a 40-foot beam there. That beam has two -- actually it has four pieces of No. 11 rebar imbedded in it and they're spliced in the center of the beam. And you can see there's hydraulic rams on either side of that beam and they're putting the -- applying force to that beam until it fails.

The next slide, please. So the two universities used two different methods to create the laminar cracks. At one university they used a -- they cast the beam in two halves. So we had a cold joint, or actually a weak joint down the middle on the plane of the splices on the rebar. The other university, they applied the force until they got a crack and then they relieved the force and then they reapplied force to crack it. The picture you see here is the second method, and you can see that the crack that was created is 0.02 inches, which is greater than any crack we saw in the shield building.

Next slide. So the results of the cracking, both universities demonstrated that in the area of the longer lap splices, the 120-inch lap slices on the top portions of the building, we got full capability from the rebar. In the areas where we had the shorter lap splices, the 79-inch, the results differed slightly depending on the method. At one university we got full capability. The other was very close to full.

So in conclusion, what we could determine was -- first of all, we did testing at two different sites using two different methodologies that were independently developed so we had very confidence in the results of what we'd obtained. Tests demonstrated that there was considerable bond strength remaining between the concrete and the rebar in these regions of cracking. And the testing was also conservative and the -- as I mentioned before when we created this beam we had two lap splices right in the area where we were applying the stress. The way the building was actually designed these were staggered, so you have a lap splice and you have a -- then you have rebar that's continuous. So the results we have are conservative actually to the actual design of the building.

All right. Finally, I'll go to my last slide here for the shield building, we established a long-term monitoring program. Now as I mentioned before, we had concluded that the laminar cracking is based on an event rather than an aging mechanism and, you know, that conclusion is supported by the concrete testing we performed. It's also supported by the analysis. However, you know, we've also monitored the shield building. We've monitored the shield building cracks now three times. We've monitored existing core bores three times since we started up back in December and we've noticed no change in either un-cracked or cracked core bores that we've investigated.

So though we don't expect this cracking to propagate, we do -- we are putting in place a long-term monitoring program and that building will -- and that program rather will inspect existing core bores for crack propagation. So we'll be inspecting core bores that are cracked to determine if the cracks changes and we'll also being inspecting core bores that are un-cracked and generally we're inspecting ones that are adjacent to each other so we could see if there was any change. We're also inspecting the integrity of the shield building coatings and inspecting the integrity of the coatings of other safety-related buildings.

And our picture here shows a couple of our engineers who are monitoring an existing core bore for any change that we would see in the cracking or the monitoring of the boroscope.

So that would complete my discussion on the shield building. Unless there's any further questions, I will turn it back over to Mr. Custer here.

MR. CUSTER: Yes, and as Ken had said, the essence of the program is as he described; monitoring more cracking in the core bores and looking at the protective coating. That aging management program has been submitted to the staff for review.

So in summary, the application's been reviewed, in many cases reviewed to NUREG-1801 Rev 2. There are 43 aging management programs that have been identified, 49 commitments, site owners and subject matter experts have been involved in the development of the application, inspections and audits and responses, all of the SER open items are currently under review by the NRC staff, and the proposed programs address the aging management of Davis-Besse for the period of extended operations.

DR. BARTON: Let me ask you a question. You're within the five-year window of license extension.

MR. CUSTER: That's correct.

DR. BARTON: There's a lot of the aging management programs that say within five years, within six years we're going to implement this program. How many of those have you implemented?

MR. CUSTER: Well, actually we just got our final SER in July. Okay? So certainly this program on the shield building --

DR. BARTON: I'm not clear that one.

MR. CUSTER: Okay.

DR. BARTON: All the other ones that fall within this five or six-year window.

MR. CUSTER: None of the new programs have been implemented as --

DR. BARTON: None of them? So you got a whole bunch of programs within that window that you got to do?

MR. CUSTER: That's correct. That's correct.

DR. BARTON: Well, good luck.

CHAIRMAN SIEBER: That's rather typical of license renewal activities and licensees use the time between the granting of the reviewed license and the start of the extended period. That's their time to prepare these programs and get them started, that they must be established by the time of the extended period of operation.

I'd like to take this time to ask the members if they have additional questions. John, you indicated that you had some?

MEMBER STETKAR: Yes, I do. I have a number though, Jack, and it may be better for us to take a break and come back and address those other issues.

CHAIRMAN SIEBER: Okay.

MEMBER STETKAR: Because if I start asking questions, we'll --

CHAIRMAN SIEBER: We won't get a break.

MEMBER STETKAR: You know me well enough by now.

CHAIRMAN SIEBER: We'll be broken.

MEMBER STETKAR: And I think John has some also.

CHAIRMAN SIEBER: Okay. And actually I think that's a pretty good idea. According to my watch, why don't we -- according to the clock on the wall, we'll come back at quarter to 11:00. So we're in recess now.

(Whereupon, the above-entitled matter went off the record at 10:24 a.m. and resumed at 10:44 a.m.)

CHAIRMAN SIEBER: Okay. At this time we'll resume our session with the applicant for Davis-Besse. And we were at the point where we were inviting questions from ACRS members. John?

MEMBER STETKAR: Yes, I'm just going to walk through there. There's no real rhyme or reason, because I just wrote these down as I went through the reports.

In the scoping analysis you have some safety-related equipment out in the turbine building, and what I focused on in particular were the start-up feedwater pump control valves, I guess. And arguments were -- this is regarding effects of non-safety equipment located in the vicinity of safety-related equipment.

CHAIRMAN SIEBER: 2 over 1.

MEMBER STETKAR: 2 over -- seismic 2 over 1 or, you know, leaks or what -- any kind of impacts that you could think about. The argument was made that those valves failed in the open position and therefore no damage from non-safety equipment could prevent them from performing that function. I have no idea how your start-up feedwater system is designed. I didn't have enough time to do that level of research. If those valves are failed open and you can't close them, how do you prevent overfilling your steam generators and isolating a lot of other things like auxiliary feedwater or whatever you call it?

MR. BYRD: Well, first of all, I think the valves you're referring to -- you've mentioned these start-up feedwater. That is -- you're probably meaning the motor-driven feed pump, I believe.

MEMBER STETKAR: I don't know. It's only -- in what I read, it was characterized as the start-up --

MR. BYRD: We had a start-up feed pump that -- and we had a motor-driven feed pump which would have a level control valve. That start-up feed pump though is not a pump that's going to be starting. That's a manually-started valve pump, so the --

MEMBER STETKAR: Let me help. Before you -- because I'll tell you entirely the sum contents of what I know. And this was a quote that I read actually in the SER, so it's a paraphrase from I guess a response to an RAI. For your reference, it's RAI 2.1-1. And it says the safety-related components of the start-up feedwater pump and auxiliary system that are located in the turbine building are the position controllers for control valves DBFV-6459 and DBFV-6460 shown on license renewal drawing LRMO-06D. These control valves fail open and the valve position controller is energized to close the valves so the associated control valve opens on a loss of signal from the controller. That's all

I know.

From that context it sounds like those valves are safety-related valves that are designed to fail -- control valves that are designed to fail open. I don't know exactly if they are directly associated with the start-up feedwater pump. It's just the context of that quote led me to believe that they are. And I know some plants actually have qualified their start-up feedwater pump as a safety-related source of water supply. As I said, I have no idea how your plant is designed.

And the question I had is if those valves indeed do fail open, what protection do you have against overfill of the steam generator? And if the steam generator does overfill, does that also isolate safety-related water -- other safety-related water supplies, or the only safety-related water supplies? In other words, is the closure function of those valves also required?

CHAIRMAN SIEBER: Yes, I might point out that in some plants the start-up feed up is also an alternate auxiliary feed pump.

MEMBER STETKAR: Yes, that's -- I've seen that. That's -- yes.

CHAIRMAN SIEBER: And you need to tell us in the case of Davis-Besse whether the start-up feed pump is used in that capacity or not.

MR. BYRD: So we have a -- we do have a start-up feed pump which is not used in that capacity. We also have a motor-driven feed pump which is used as an alternate auxiliary feedwater pump, however, it is a -- it is only manually initiated. So in other words, it's the -- our steam feed rupture control system would only manually initiate our two steam-driven auxiliary feedwater pumps. Now the two auxiliary -- the two steam-driven auxiliary feedwater pumps are actually located in the auxiliary building. They're located in -- they have their own room, which is actually accessed through the turbine building, but it is a part of the auxiliary building. So the particular valves which would be controlling from the auxiliary feedwater pumps would be contained with the auxiliary building.

MEMBER STETKAR: Well, I guess my question is then is there a concern with these two particular valves that I've cited, because as I said, the only thing that I've read leads me to believe that for some reason they're safety-related valves. And not having a flow diagram of your systems, I couldn't go find out what those valves --

MR. BYRD: Yes, discussing the overfilling issue, if I could have Dennis Blakely, our analysis supervisor -- I think he could provide a little bit more of that, how we analyzed the overfill.

MEMBER STETKAR: By the way, if you don't have a quick answer, we're here all day. You know, you can do some homework over lunch.

MR. BYRD: That's right. Just trying to understand the question.

MR. BLAKELY: I'm Dennis Blakely, the engineering analysis supervisor. The auxiliary feedwater pumps, as Ken said, are located in a separate -- or separate rooms of the auxiliary building and they have level control valves associated with them and they are protected -- they are within those auxiliary feed pump rooms.

The valves you're referring to are associated with the motor-driven feed pump, which is a manually started pump. And the boundary for the system would include check valves that would prevent overfeed.

Now, the operators also have the capability to shut off the motor-driven feed pump if those valves would fail open, if they had started it. Okay?

MEMBER STETKAR: If they had -- but --

MR. BLAKELY: But they -- that pump is not relied upon within the safety analysis for the mitigation of accidents. So those valves are also not relied upon.

CHAIRMAN SIEBER: Is that pump used during normal operation?

MR. BLAKELY: It's used for -- in normal operations for plant start-up and shutdown. But in that case it's a line to the main feedwater system rather than to the auxiliary feedwater system, so it's going in the main feedwater headers of the steam generators rather than the auxiliary feedwater header.

CHAIRMAN SIEBER: And when you get to a certain power level that pump just shuts down?

MR. BLAKELY: Once the main feed pumps are started up and supporting plant operations, the motor-driven feed pump is shut down and realigned to the auxiliary feedwater pump so that it's available for the operator should they need it.

CHAIRMAN SIEBER: And that occurs at what, 20 percent power? Is that about --

MR. BLAKELY: Approximately. Yes, sir.

CHAIRMAN SIEBER: Okay.

MEMBER STETKAR: Okay. Thank you. That solves my question about that.

I have several notes here, and if you'd just bear with me because in the interest of time I'll try to do some screening.

The bolting integrity program. There's some discussion in the SER and responses to RAIs about your examination program for high-strength bolting. And the response that I read said the applicant further stated in response to RAI B.2.4-1, that volumetric or surface examinations are not currently conducted to detect stress corrosion cracking on bolts; these are high-strength bolts, since no instances of failed bolting of bolted connections due to stress corrosion cracking had occurred at Davis-Besse. Applicant stated that visual examinations of structural components will detect corrosion or corrosive environment that leads to stress corrosion cracking.

I'm not a materials person; I may need help from our materials people here, but it seems to me just because you haven't had any fails -- failures doesn't provide me a lot of confidence that you shouldn't check for conditions that might cause cracking. And I know that your reactor vessel head closure studs are high strength material. What other bolts in the plant are those high-strength materials?

MR. BYRD: I'll ask my core team. Do we have a response to that that we can provide right now?

MR. KOSLOFF: Don Kosloff with the core team. I'm the civil structural lead.

I've looked at several drawings and we have quite a few structural bolts that are high- strength.

MEMBER STETKAR: That are high-strength?

MR. KOSLOFF: It would be difficult to give a list --

MEMBER STETKAR: Okay.

MR. KOSLOFF: -- of how many there are, but there are quite a number of them.

MEMBER STETKAR: Let me ask our other two -- Dr. Armijo and Dr. Shack, because I am now well past anything that I know anything about. Are surface visual inspections adequate?

MEMBER ARMIJO: Have to be pretty severe.

MEMBER STETKAR: I mean, the Yale report recommends volumetric examination.

MEMBER ARMIJO: Yes. Yes.

MEMBER STETKAR: That's --

MEMBER ARMIJO: Sometimes people do penetrating exams.

MEMBER STETKAR: Yes.

MEMBER ARMIJO: But, no, if you really thought you had a cracking thing potential --

MEMBER SHACK: You'd want to get it before it failed.

MEMBER ARMIJO: That's right. Right, they're not --

MEMBER STETKAR: Oh, but they're just volumetric. They're proposing simple, right, you know, visual --

MR. BYRD: I think we have our bolting engineer here. I turn -- I'm sorry, Jake Hofelich?

MR. HOFELICH: Jake Hofelich, ISI program owner. Some of the bolting is examined ultrasonically. The bolting within the section 11 ISI program, the reactor head closure studs in particular, each stud is examined each 10-year --

MEMBER STETKAR: Yes, I read that.

MR. HOFELICH: And also the other systems, class 1, 2 and 3 systems are pressure tested and we look for any evidence of degradation or any leaks that would be a result of any cracking in the bolting.

MEMBER STETKAR: Yes, but that's after the failure has occurred.

MR. HOFELICH: Correct.

MEMBER ARMIJO: What's your history with those bolts?

MR. HOFELICH: We have not had any cracking indications in the record at closure sites.

MEMBER ARMIJO: I saw the magic words "moly disulfide" somewhere. I keep wondering. I thought that disappeared when I was a young man, younger than you.

MR. HOFELICH: The lubricant that we previously used contained molybdenum disulfide. And one of the commitments in our license renewal application is to preclude the use of that reactor head closure studs.

MEMBER ARMIJO: Better late than never.

MEMBER STETKAR: I'll have to think about that one. Buried piping. I understand that your diesel fuel oil piping is cathodically protected, right? And you're upgrading that system, is that correct?

MR. BYRD: That's correct.

MEMBER STETKAR: And you're going -- are you going to protect -- provide cathodic protection for the service water piping?

MR. BYRD: To discuss our buried piping, we have our program owner Frank Zurvalec here.

MR. ZURVALEC: My name is Frank Zurvalec. I'm the buried pipe program owner at Davis-Besse. And our cathodic protection system is approximately 30 -- or 70 percent complete, the restoration. We spent approximately $2 million. We still have one phase left to go. Currently the diesel fire pump piping, buried piping is cathodically protected. That was installed either this year or last year.

DR. BARTON: How effective is the cathodic protection system that you do have installed? I know you're still working on it, that you've got some installed. How effective is it?

MR. ZURVALEC: We monitor it for the base guidelines monthly voltage current readings and also yearly ground potential readings.

DR. BARTON: Ninety, ninety-five percent effective, or --

MR. ZURVALEC: I don't have that number. The cathodic protection engineer is back at our site, but I would argue at least 99 percent.

MEMBER STETKAR: I'm not sure you answered my question. I was asking you about the service water piping.

MR. ZURVALEC: Service water? I thought diesel fire pump.

MEMBER STETKAR: No, I --

MR. ZURVALEC: Our service water piping that's been scoped is cathodically protected at this time.

MEMBER STETKAR: At this time? But it has not in the past, is that correct?

MR. ZURVALEC: The service water cathodic protection was reestablished again either this year or last year reestablished.

MEMBER STETKAR: Oh, it did have cathodic protection in -- at --

MR. ZURVALEC: At one time it did. It had fallen into a state of disrepair.

MEMBER STETKAR: Okay.

MR. ZURVALEC: But our plans are to cathodically protect all of the buried lines within the protected area. All of the pipes, all of the buried lines within the scope of the license renewal are currently cathodically protected.

CHAIRMAN SIEBER: How long in the history of Davis-Besse did the plant go without serviceable cathodic protection?

MR. ZURVALEC: I would argue the vast majority of time. I do not have those details, but originally after construction and start-up the cathodic protection system fell into disarray and was not maintained properly. Through industry discussions and the shared operating experience at the license renewal, I think the industry has embraced the idea that cathodic protection is an integral part of the health of the buried piping system and must be reestablished and maintained.

CHAIRMAN SIEBER: So you probably got 25-30 years of issues with the buried piping where you did not have protection established?

MR. ZURVALEC: That's a good estimate, but again with our buried pipe program we are doing inspections of the line that we have, opportunistic inspections. I do not see a degraded condition. As long as the coating is intact, we did not have to rely upon the cathodic protection system. It's only when that coating has been degraded or damaged that will cause a problem, and that's what that cathodic protection system is for.

CHAIRMAN SIEBER: Okay. That's degradation from the exterior of the pipe?

MR. ZURVALEC: That's correct.

CHAIRMAN SIEBER: Have you done examinations of -- other than opportunistic where you actually physically go down and make measurements on the pipe in the -- including wall thickness and --

MR. ZURVALEC: Yes, sir.

CHAIRMAN SIEBER: -- the interior surface?

MR. ZURVALEC: Direct examinations. We've performed direct examinations of our -- some of our service water piping, various pipings. And the coating that I've seen has all been intact. It's not delaminated. It's not cracking. We have removed some coating to perform ultrasonic examinations. Then we establish that coating again. But there has been -- the pipe that I've inspected is in new condition.

MEMBER STETKAR: It's also service water? I mean, there's a lot of focus on --

MR. ZURVALEC: It includes portions of the service water system.

MEMBER STETKAR: Okay. Okay.

MR. BYRD: Just to make sure you understand, the main service water discharge and supply headers are actually in a tunnel, so they're not buried.

MEMBER STETKAR: So it's an underground?

MR. BYRD: It's underground, but it's in a tunnel. Okay?

MEMBER STETKAR: Okay. Thank you. Let me make a note here.

Kind of following up, the -- I couldn't follow the story -- there's a story about materials in your firewater system that are copper alloy with zinc. And originally, as I understand it, inspections of that material for possible stress corrosion cracking were in one of the programs. I don't have my whole list here. It was in one program, but the staff had questions about it. You said, well, we'll take it out of the program. And then it kind of popped up in another one and it was taken out of there. I can't find now any --

DR. BARTON: It's in an aging --

MEMBER STETKAR: Now we're --

DR. BARTON: It's in aging management program now, fire --

MEMBER STETKAR: Where? Well, but not -- I don't think for these alloys.

DR. BARTON: Oh, no, it's --

MEMBER STETKAR: That's -- what I want -- the whole key, I think, is, as I finally walk my way through all of this, in an initial response it says the applicant also stated that they could not verify the absence of ammonia in it's raw water source to be below a threshold concentration in which cracking would not be a concern. There are several negatives there, but basically it says you couldn't -- you thought there might be enough ammonia to cause cracking. And then as I understand it, all of the following discussions wherever it pops up and questions were asked, you finally said that operating experience did not identify ammonia or ammonium salt in the raw water or cracking of comparable alloys in the associated system. Do you know that you don't have raw water chemistry that would facilitate cracking in that material?

MR. BYRD: We have Alvin Dawson here, our chemistry manager who can --

MEMBER STETKAR: Beyond a shadow of a doubt?

MR. DAWSON: Alvin Dawson, chemistry manager. In answer to your question, yes, we know. We drew samples on our raw water system both going in and going out after that question was raised. All those samples were sent out for analysis and we have no ammonia --

MEMBER STETKAR: Okay.

MR. DAWSON: -- in our raw water system.

MEMBER STETKAR: Thank you. Ground water. Asked a little about groundwater earlier with regard to the containment shell and I wanted to follow up on a couple of other things.

You've committed to sample the groundwater system during a period of extended operation at least once every five years. Do you have in place and have you had during the operating history of Davis-Besse a groundwater sampling program? In other words, you've committed to something. Sample every five years means you get three or four during the period of extended operation to look for trends in the groundwater chemistry. Do you have any idea about past trends in the groundwater chemistry?

MR. BYRD: Yes, we do and Alvin Dawson here would be able to explain that.

MR. DAWSON: Again, Alvin Dawson, chemistry manager. We have had a groundwater system -- a groundwater sampling system in place at Davis-Besse for a number of years. In 2007, when NEI 07-07 came out, we instituted a more rigid groundwater sampling program. Right now we sample groundwater every six months for tritium and hard gamma emitters and different species that we're interested in. We sample every six months and if --

MEMBER STETKAR: Do you sample for chloride, sulfates and pH? I'm not interested in sampling for radionuclides. I'm interested in sampling for water chemistry, aggressive water chemistry.

MR. DAWSON: Oh, you're referring to the five-year commitment for water chemistry?

MEMBER STETKAR: That's -- yes.

MR. DAWSON: We do -- on that five-year basis we sample for -- we do sample for pH on a regular basis, but for chlorides and sulfates we do sample every five years.

MEMBER STETKAR: Has that been done in the past during the last 35 years of operation, or is that just something you're going to start in 2017?

MR. BYRD: Alvin, I think Donald has something to add to that. Don Kosloff?

MR. KOSLOFF: Yes, there's a bit of confusion in the SER.

MEMBER STETKAR: Okay.

MR. KOSLOFF: Donald Kosloff, license renewal core team, structural civil engineer. We followed GALL Rev 1 in our application, which required sampling of groundwater if the groundwater is non-aggressive. It had no requirement for sampling if the water was determined to be aggressive. We determined that the groundwater was aggressive and we did not commit to sample groundwater. We committed to sample raw water; i.e., lake water because the lake water is non-aggressive and we want to monitor that to make sure that it doesn't become aggressive.

MEMBER STETKAR: That's -- I didn't want to bring that up, but I saw the commitment to sample raw water and I thought that might have been a typo. Apparently it's not. Apparently that response was very carefully worded.

So you're not actually going to sample groundwater to determine its chemistry?

MR. KOSLOFF: There is no plan at this time to sample groundwater for sulfates, chlorides or pH.

MEMBER STETKAR: Okay. So you're just going to rely on your basic opportunistic inspections of below-grade structures whenever they're exposed. And as I -- and I wanted to ask you about -- I know you're going to take a couple of core bores --

MR. KOSLOFF: Right.

MEMBER STETKAR: -- from the turbine building and the ECCS pump room, I guess. Let me ask about the core bores. The groundwater level, as I understand it, nominal is about 570 feet, is that right?

MR. KOSLOFF: That's correct. Dick Bair of our structural engineering group can provide a more detailed answer on that.

MEMBER STETKAR: Okay.

MR. BAIR: Richard Bair, design engineering. As you stated, we are planning on taking two of the core bores; one in our turbine building, one in our ECCS pump room, which is in the auxiliary building. Those cores will be taken deep into the structure so we can access the portion of the concrete most likely to potentially be affected by the aggressive groundwater. We will be testing that in concrete and our commitment -- we have a license renewal commitment to perform these two initial core bores by the end of 2014. And we have additional commitments to perform core bores in the future if groundwater infiltration persists. I plan on entering the information from these core bores into our corrective action program for tracking and that will also allow us to initiate any additional corrective actions that may be necessary for this condition.

MEMBER STETKAR: Thank you. You said the core bores are going to be deep. Any estimate of -- because you're boring from the interior going out, you'd expect the problem if there is any to be progressing from the exterior in. So will they go completely through wall, or --

MR. BAIR: No, we're not planning on going completely through wall. We're planning on going to approximately the lowest -- in the case of the ECCS pump room, we'll be going through the actual foundation mat of the auxiliary building. So we'd be going to approximately the depth of the bottom rebar mat. And in the turbine building it would be on walls, so we would be core boring approximately to the location of the outer rebar mat, which would be -- leave a couple inches of concrete in each one of those locations.

MEMBER STETKAR: Okay. Bear with me here. I've got one more question. I'm a slow writer.

One last simple question: And in the turbine building, at least again from what I've read said that the core bore would be at the turbine building condenser pit at approximately elevation 573, which as I understand is about 3 feet above groundwater level. Why not below groundwater level in the turbine building, or is that a typo?

MR. BAIR: Offhand I'm not sure how we selected that specific elevation. We will be taking one at a sufficiently low elevation to ensure that we're getting a portion of the structure that potentially had been affected by the aggressive groundwater.

MEMBER STETKAR: Okay. You may want to check that. I pulled that out --

MR. BAIR: Okay.

MEMBER STETKAR: It's in the SER. It could be a typo. I recognize -- we don't get all of the RAIs and the responses, nor do we want them. We have enough to read.

MR. BAIR: Right.

MEMBER STETKAR: And sometimes things get paraphrased a little bit.

MR. BAIR: As I prepare the engineering change package for these core drills, I will double check that. I will be sure it's --

MEMBER STETKAR: Yes, it's just --

MR. BAIR: -- sufficiently low to capture the zone affected by the aggressive groundwater.

MEMBER STETKAR: Okay. Thank you. Two more: You've had some slope slippage -- or I'm not a geotechnical engineer, so I don't know the correct terms -- in your intake canals. Can you tell us -- and I know you've done a bunch of analyses that -- you had divers go down. They say the tow hasn't come out. apparently a couple of geotechnical analyses came back. As I understand, it was sort of differing opinions about the current condition of the intake canal. Can you show us -- there was one photograph. What's the extent of that area that slipped --

MR. BYRD: Do we have --

MEMBER STETKAR: -- in terms of --

MR. BYRD: We have --

MEMBER STETKAR: Yes, that's the photograph I was looking --

MR. BYRD: -- Joe Brunkhorst here who can explain this for us.

MR. BRUNKHORST: Joe Brunkhorst,

structures monitoring program owner. Would you like me to come up front and point --

MEMBER STETKAR: It would help. I mean, if you have a -- but the problem is you have to be near a microphone or a --

MR. BRUNKHORST: I understand.

CHAIRMAN SIEBER: Yes, you may want to do it with a mouse.

MR. BRUNKHORST: Okay. So the intake canal entire length is approximately 2,700 feet, and the Q-safety-related forebay is about 700 foot long from the face of the intake structure. So approximately right where the hand is there's an area -- two areas that are side by side that equal approximately 150 feet where this localized settlement is taking place.

MEMBER STETKAR: And then we say -- when you say "localized settlement," is it an actual slip, or is it a -- what's the configuration?

MR. BRUNKHORST: It's more -- it's a shelf. It's more --

MEMBER STETKAR: Okay.

MR. BRUNKHORST: It's created more of a shelf and it's actually settled down more between the top of the bank and the edge of the water. That's what the diver confirmed with the tow of the --

MEMBER STETKAR: So you actually haven't seen a slip?

MR. BRUNKHORST: There has been some minor slippage into the canal. We had a slope stability study recently finalized where they had installed two sloping inclinometers into two of the cores that were installed and they over a six-month period saw minimal movement in a magnitude of approximately a quarter of an inch. So what that did though confirm is where exactly that failure plane was in the canal.

MEMBER STETKAR: So you have confidence and you understand where the failure point is?

MR. BRUNKHORST: Yes. Yes.

DR. BARTON: Do you have some work scheduled to do in the intake canal in that area?

MR. BRUNKHORST: Yes. Yes, we're currently putting together the engineering change package to make a repair to that area.

MEMBER STETKAR: Do you know what you're going to do with it?

MR. BRUNKHORST: The current repair option that's being pursued to actually install sheet pile in the area.

MEMBER STETKAR: Okay.

DR. BARTON: I don't know, on the intake

now while you're -- want me throw it in here? The description says you have water protection dikes that are seismic class 2 earthen dikes constructed of topsoil. My question is, you know, what prevents washout of the topsoil in the event of severe wave action in your intake? What am I missing here?

MR. BRUNKHORST: The entire length of the canal is protected by riprap. I mean, as far as wash-away from normal erosion factors, I mean, it's protected by armor stone riprap. Yes, on both sides of the canal, both sides of the dike.

DR. BARTON: So that's protecting this topsoil from getting washed out, the riprap on the side?

MR. BRUNKHORST: Right.

DR. BARTON: Got you. All right. That was it, John.

MEMBER STETKAR: Good, John? I only have one more. For your environmentally-adjusted usage factors in your fatigue monitoring program, I understand how you -- first of all, I understand that you're basically using a counter, a count -- a cycle counting process primarily to -- as the primary means of keeping track of this. And I read, you know, how you extrapolated the past operating experience linearly to come up with your number -- projected number of cycles of 60 years, except for the pressurizer surge line, which has an environmentally-adjusted cumulative usage factor of 0.996, I believe. And what I've read is -- said, well, with the nominal number of heat-up/cool-down cycles of 128, which is projected just using a linear extrapolation from the historical data you couldn't meet the project cumulative usage factor of less than 1.0. As it's characterized at least in the SER summary of the RAI, it says that the applicant stated that alternatively it used a best estimate 60-year projected cycle for heat-up/cool-down cycles which is based on more recent operating experience compared to the entire operation history of the plant. This resulted in a best estimate 60-year projected cycles of 114 cycles for the heat-up/cool-down transients.

My background is risk assessment and uncertainty analysis, so I'll cast it in this context: when I think of a best estimate analysis, I think of -- some people think of median, some people of means, but it's something that I've done an analysis, looked at variability and uncertainty and derived a value that I feel is my best estimate.

Could you explain to me; and probably not in this venue -- what I'm interested in is what is the extent of your more recent operating experience and what analyses did you use to actually derive this best estimate which miraculously just gets you below 1.0?

MR. CUSTER: I ask my team member Larry Hinkle to --

MEMBER STETKAR: Because that's just really, really surprising that it would just get you below 1.0 if it's a best estimate.

MR. CUSTER: 0.998?

MEMBER STETKAR: 0.996 I think it is, not 0.988. It's 0.996. They gave them --

MR. HINKLE: I'm Larry Hinkle with the license renewal project team. That was based on cycles accrued since approximately 2008 -- excuse me, accrued since approximately 2000 up to present day. When we say "best estimate," it was based on the rate of occurrence since that time frame. And there's a slight bit of margin added in there --

MEMBER STETKAR: Okay.

MR. HINKLE: -- but the most part it was a -- it was just based on the rate of occurrence.

MEMBER STETKAR: We'll do this as a take-away. What I'd like to see is your historical plot or tabulation of number of heat-up and cool-down cycles per year over the entire life of the plant so that I can see what the slopes look like. And if you have documentation of how you did that extrapolation, what margins, I'd be interested in that. It's just really surprising to me that it worked out to this miraculously getting you just below the limit. Oftentimes when you look at variability and uncertainty, you know, if you included one more year in the experience, you might not have had that.

MR. HINKLE: Understood.

MEMBER STETKAR: So I'd really like to see what those slopes look like and how you did that.

MR. HINKLE: Okay. At the time that this occurred AREVA was performing the evaluations for us, and they contacted me personally. I was the TLAA lead. And basically they told me -- well, they told me the number of cycles it would take to be able to pass this say under 1.0. However, from there, right, I went in and I personally looked at the cycles that occurred from 2000 up to present day at that time of the phone call, which was a couple years ago here now.

MEMBER STETKAR: Yes.

MR. HINKLE: We looked at those cycles. And then from there I determined that I could even come up with a lower number than what they needed. And so I added some margin back in just to account for some unknowns and things that might occur down the way that we didn't anticipate.

MEMBER STETKAR: The only -- and in some sense this is a bit of a moot point because I understand you're just setting a speed limit for yourself and essentially it's -- on my street the speed limit is 30 and on the next street a block over it's 35, and you're monitoring your performance so that you're not passing a speed limit of 30, you know, for this particular failure mechanism. The thing that I'm hanging up on is -- the use of the term "best estimate" in the world these days really means something. It's not just setting a nominal speed limit. And indeed, if you're characterizing that as a best estimate, I wonder -- I want to understand why it is that. If it's just simply the number of cycles such that the value is less than 1.0, that's not necessarily a best estimate. It's an arbitrary speed limit.

MR. HINKLE: No, this is -- this number of cycles was based on the rate of occurrence --

MEMBER STETKAR: Okay.

MR. HINKLE: -- since the year 2000. And so when I -- and I came up with the term "best estimate." I thought that was the best term I could come up with. I wanted to be able to distinguish between that and the other 60-year projections we had performed.

MEMBER STETKAR: Well, I'd like to see how you did that.

MR. HINKLE: Okay.

MR. CUSTER: We can provide that, Mr. Stetkar.

MEMBER STETKAR: Thank you.

MEMBER SHACK: Just a quick follow-up on that. All those CUFs are based on ASME-type code calculations? You haven't done a -- you haven't redone the stress analysis to get those numbers lower?

MR. RINCKEL: Mark Rinckel with the AREVA license renewal team. Yes, they're based on ASME code calcs, or the original stress analysis. So there hasn't been anything --

MEMBER SHACK: Any reanalysis?

MR. RINCKEL: No, not for the NUREG-6260 locations.

MEMBER SHACK: Now you're going to do more locations, right?

MR. RINCKEL: Yes, we identified additional ones, so that's a commitment.

MEMBER SHACK: Yes, it's the highest one for each material type?

MR. RINCKEL: That is correct.

MEMBER SHACK: But that hasn't been done yet?

MR. RINCKEL: That's beyond the NUREG-6260 locations. Yes, that's correct.

MEMBER STETKAR: I don't have anymore.

CHAIRMAN SIEBER: Okay.

MEMBER STETKAR: I don't know if John has any.

DR. BARTON: Yes. I couldn't find in your small bore piping, class 1 piping inspection what you committed in regards to inspection of socket welds. Can you help me out here? Do you have a number? A percentage?

MR. BYRD: I'll let Jake Hofelich, our small bore piping inspection lead --

MR. HOFELICH: I'm Jake Hofelich. I'm the small bore piping program owner. The inspections are 10 percent of the weld population, or maximum 25 for each weld type, socket welds and full penetration welds. Our sock weld population is approximately 437, so we'll be performing 25 of those. Alternatively, we can perform 13 destructive examinations if a qualified ultrasonic technique is --

DR. BARTON: Got you. I understand.

MEMBER STETKAR: And your other world

population is like 180 or so, right?

MR. HOFELICH: The full penetration weld is approximately 180, yes.

DR. BARTON: Right. Okay. I've got a question on tanks in general. Your water storage tank, diesel oil tanks and your borated water storage tank could determine whether caulking at the interface at the tank to the foundation is required on these tanks. And if so, is it installed? Because you had an experience several years ago where the diesel oil storage tank had rust and corrosion at the base flange and corroded bolts at the lower access plate at the tank base.

Now have you fixed that? And do you have these tanks insulated at the foundation to the lower tank flange on these things?

MR. CUSTER: I think the history on that, we'll have to get back to you at lunch time. Right now we don't -- we don't have anybody who can answer that question with us right now.

DR. BARTON: Well, I'm concerned because I have some experience of tanks that get corroded in the bottom, start leaking, etcetera. And it looks, from what I read your, history is maybe that you've got some of that going on. And I'd like to know the status of

-- do you require insulation at that interface at not?

And also, you said that you're going to look at the initial tank bottom inspection of firewater storage tank, you know, some 40-45 years after it was installed. And that tank, according to what I read, does not have any sealing material. And I question, you know, doing an initial inspection on a tank that is not insulated from this foundation after that many years. So that's a concern I've got. MR. ALLEN: With respect to the firewater tank, I think Donald can talk to that once we fix this.

MR. KOSLOFF: I dropped my microphone ball.

The firewater storage tank was replaced -- I believe it was about 20 years ago. I don't -- somebody in design remember when that was done?

MR. HOFELICH: Yes, the firewater storage tank I believe was replaced in the 1980s.

MR. KOSLOFF: That's addressed in the application in the operating experience discussion. I believe it's for firewater system.

MEMBER STETKAR: But the bottom edge of that tank is not sealed --

MR. KOSLOFF: That is correct.

MEMBER STETKAR: -- to the foundation.

MR. KOSLOFF: That is correct. The firewater storage tank is a concrete ring foundation with a oil/sand base. And that's also discussed in the --

DR. BARTON: Well, I know it's on an oil/sand base, but I've known tanks on oil/sand bases that have also had problems, leakage problems.

MR. KOSLOFF: Right. And --

DR. BARTON: So if it's on that, it does not preclude any problems with that tank, so --

MR. KOSLOFF: And we're going to inspect that tank periodically.

DR. BARTON: How about the other ones? Do they require insulation around there or not?

MR. KOSLOFF: The only thank in the above-ground tanks program that's insulated in the borated water storage tank. The other two tanks -- or the other tank and the borated water storage tank, which would be the diesel oil storage tank and the borated water storage tank, require a caulk seal at the base.

DR. BARTON: And that is installed as far as you know?

MR. KOSLOFF: As far as I know. Yes, sir.

DR. BARTON: Okay. I had a question here

on switchyard work. Trying to find out what your relationship here to -- I know you need the switchyard for off-site -- loss of off-site power, but I read in one of the inspection reports the -- there was a question on the status of some concrete repairs that needed to be done on switchyard tower foundations which were identified in station condition reports. A work order was submitted to the FirstEnergy switchyard people and it turns out that the work order and condition reports were closed out by the switchyard department responsible for the work with no work being done and no reasons given.

My question is, you know, what relationship do you have with FirstEnergy's switchyard people and do you understand why the work wasn't done, or was it just okay they closed it out?

MR. BYRD: So the relationship we have is obviously we do not at this point do the maintenance on the switchyard.

DR. BARTON: I understand that.

MR. BYRD: We did actually until fairly recently, but we turned that over to the transmission. We do provide oversight over that work, however, and that's done by our electric shop which provides oversight whenever we have ongoing work in the switchyard.

With regards to the transmission tower concrete, Mr. Hook, if you could provide us with an update on that?

MR. HOOK: Jon Hook, design engineering manager. So for the transmission foundations, there are caissons going down to bedrock and there's been some degradation underneath the base plate. We have done repairs of that in the past. That's where most of the material is -- degradation is associated with brick down to the base plate.

We did take a look at that. There's ample margin in the design for that. And there is some spalling along the exposed concrete caissons that come up, and that's all surface. It's not structural.

DR. BARTON: So the fact the work wasn't done, you've agreed with -- you've looked at that and you've agreed it wasn't required, or what? It just --

MR. HOOK: It is required to prevent further degradation. So that's part of our maintenance rules for structures during our walk-downs. We go through that and inspect it and identify it. If it's appropriate, we either write a notification to get it fixed or a condition report.

DR. BARTON: So in this case how did this end up?

MR. HOOK: The current condition right now is acceptable.

DR. BARTON: It's acceptable?

MR. HOOK: Right. It's just minor, minor surface spalling and degradation. Not a structural concern at this time.

MEMBER STETKAR: John, you're asking about a specific event, right?

DR. BARTON: Yes, what I want to know is they didn't do the work, returned the work order or whatever with no reason why they didn't do the work. And that's what bothers me.

MEMBER STETKAR: Okay.

MR. BYRD: I don't have the details of why --

DR. BARTON: This was in an NRC inspection report is where I got this.

MR. BYRD: Right, and I don't --

DR. BARTON: And that was due to looking at the paper and talking to people while they were doing the inspection.

MR. BYRD: So I don't --

DR. BARTON: And that's the problem I've got.

MR. BYRD: Right, I don't have the details of that specific issue. We can follow up with that.

DR. BARTON: Okay. I appreciate that.

MR. BYRD: And I'm sure there's more history to that.

DR. BARTON: You have inaccessible medium-voltage cables not subject to 50.59 EQ requirements. I noticed that you've got water problems in manholes and cables wetted, etcetera. You had stated that you were going to improve the water quality removal capability of the sump pumps. Has that been done?

MR. BYRD: I we have Eric Johnson here to provide some additional information on that.

MR. JOHNSON: Eric Johnson, electrical programs at Davis-Besse.

Yes, we did have water problems in a manhole that supplies -- for our station blackout diesel generator cables. And we did put a sump pump in that manhole approximately one year ago. We have two other manholes associated with cables that go to the switchyard relay house that has some drainage issues. And we have an engineering change package that will be scheduled to be implemented next spring that will provide drainage to an adjacent manhole that has a sump pump.

DR. BARTON: So in the meantime what are

you doing to exclude water? More inspections or pumping it out manually? What are you doing in the interim until you implement that work order?

MR. JOHNSON: We just submitted a change request to the PM program to inspect that -- those manholes every 30 days --

DR. BARTON: Every 30 days?

MR. JOHNSON: -- or as required.

DR. BARTON: Now do you also require inspections in severe weather conditions? You got rain that comes down, it pours for three or four days and does that tick off something that says we ought to go look in the manholes?

MR. JOHNSON: That's in our aging management program. We haven't determined what the event is yet or how to quantify that.

DR. BARTON: So in the meantime you have a heavy rain, you don't do anything different other than inspect every 30 days or whatever?

MR. JOHNSON: That's correct.

DR. BARTON: Okay. I'm not okay about, but I understand what you said.

Question on the makeup purification system. I read where you every seventh refueling cycle replace your letdown coolers, and I've looked at other plants and I don't recall other plants having to change out letdown coolers every seven cycles because they can't repair them. There's got to be a root cause for this problem and I'd like to know if you've looked at it and determined what the root cause is, and why did you select replacing your letdown coolers every 14 years. I don't understand why you can't fix the problem that causes letdown coolers to degrade to the point where you have to buy new ones every 14 years.

MR. BYRD: I know our letdown coolers are somewhat a unique helical-type design, but I don't really have the answer to your question. We'll have to follow up with that, unless someone anyone else on our --

MR. ALLEN: Allen, would you like to comment on that?

MR. McALLISTER: Allen McAllister, license renewal team. Yes, our letdown coolers, they're a helicoil design. That design of coolers throughout the world, whether it's in the Navy, whether it's in the nuclear industry, have a high-cycle fatigue problem. Basically the spiral tries to un-spiral so you're creating these stresses in there. To take them apart to do a detailed failure analysis, it's a high dose item. A lot of effort has been put forth in the industry to try to do something different. We've made progress as an industry. Various plants that used to replace their coolers every three years got them up to five years. The plant that actually had the worst history has now got theirs up to 20 years.

So in the time being we have our PM in place so that we have spare coolers so that if the thing starts to leak, we'll pick that up in the chemistry analysis and replace the coolers. But at this point just based on the design, based on industry experience, world experience, Navy experience, there's not a clear success path other than at some point you're going to have to replace these.

DR. BARTON: Nothing like a different design cooler will work?

MR. McALLISTER: Essentially the place -- the people that use this design was space considerations, which is why we used them in the Navy, why they were copied and put in our plant.

DR. BARTON: Did you replace them this often when you were in the Navy?

MR. McALLISTER: Actually it was I believe every 10 years. I remember when my sub was at the Portsmouth Naval Shipyard that that's one of the activities that we did. I think that was a 10-year frequency.

DR. BARTON: All right. So it's an industry problem and you're going along with the industry and changing them out every so many cycles?

MR. McALLISTER: Yes, I mean, we're seeing what we could learn. You know, I don't want to drop their name, but you know, one plant has gone from basically a three-year life expectancy to a 20-year life expectancy. So we're seeing what we can learn from them, what they changed, what they did different or the same to see what we can do to increase the livelihood.

DR. BARTON: All right. Thank you. I just -- it just seemed strange that instead of trying to get to the root cause of a problem you keep changing them out. So I understand.

In-service inspection program, IWF. I noticed that you have operating experience that showed you had rusted areas on I-beam supporting the service water piping, which appears to be from condensation on the service water piping dripping onto the I-beams. Your corrective action evaluation on this deficiency determined there was no action required. You know, that tells me you're willing to continue with this condition for an extended operating period of 20 more years instead of insulating the service water piping. What am I missing?

MR. HOFELICH: I'm Jake Hofelich. I'm the IWF program owner. Those supports were examined in accordance with ASME section 11 and found to be acceptable within the acceptance criteria.

DR. BARTON: I'm sorry, I didn't hear the end of that.

MR. HOFELICH: They were -- the supports were examine in accordance with ASME section 11.

DR. BARTON: Right.

MR. HOFELICH: And as part of the acceptance criteria the design engineering group took a look at it and saw it could fulfill its function as it and it was found to be acceptable.

DR. BARTON: So you're going to continue with the problem?

MR. HOFELICH: It's found to be acceptable.

MR. BYRD: Jon Hook, can you add anything to that from the structural side?

MR. HOOK: We continue to monitor those pipe supports, and there's ample margin inside the calculation and ample thickness such that any degradation in there is not a concern and --

DR. BARTON: So it's rusting very slowly, so you're going to live with it? Is that the answer?

MR. HOOK: We're inspecting it and managing it.

DR. BARTON: I understand.

MR. HOFELICH: It should also be pointed out that these are periodic inspections, so hangers are continually looked at and -- hangers in that tunnel, and usually the same hangers are looked at again at the next interval. So will continue to monitor those hangers and the adjacent hangers in the service water tunnel.

DR. BARTON: Open cycle cooling water system.

MR. BYRD: Excuse me, Mr. Barton?

DR. BARTON: Yes?

MR. BYRD: I believe Mr. Blakely --

DR. BARTON: We got something else? All right.

MR. BLAKELY: Dennis Blakely, engineering analysis supervisor.

With respect to correcting the condition of the condensation, that interplays with the Appendix R fire protection program because the type of insulation material that would be used. There's a significant fire load on the spaces. And that's the reason that we're not addressing the condensation and taking the approach of managing this.

DR. BARTON: So all anti-sweat insulation gives you an Appendix R problem?

MR. BLAKELY: The types that we use in our plant; yes, sir.

DR. BARTON: Isn't there other types that wouldn't give you an Appendix R problem?

MR. BLAKELY: I've not heard of others that would address the issue.

DR. BARTON: Open cycle cooling water. In operating experience you mentioned in 2008 that you found a silt layer in the piping between two valves related to auxiliary feedwater system and you flushed it and got rid of the silt.

My question is how do you know that you don't have recurrence of this issue, and how would impact the operation of the auxiliary feedwater system if it did recur?

MR. CUSTER: Can you restate that question?

DR. BARTON: You got silt between two valves in the auxiliary feedwater system.

MR. CUSTER: Okay.

DR. BARTON: You flushed it out and got rid of the silt. That's end of story. Now I'm saying, well, how do you know that you're not going to get silt accumulated again? If you do get a bunch of silt between the two valves, how will that affect the auxiliary feedwater system if you got to operate these valves and it goes to a pump or -- I know what these valves do. So, yes, how do you know that you solved the problem long term?

MR. BYRD: I believe we do periodic flushing, and that's something we'll have to verify and get back with you on. I don't have any information with me right now.

MEMBER STETKAR: Just for clarification, when I read that, if you could clarify, it was assuming that's an alternate suction from your raw water system.

MR. BYRD: That's an alternate suction from the raw water system to auxiliary feedwater. It's a stagnant line.

MEMBER STETKAR: Yes.

MR. BYRD: And my recollection is; and I need to verify this, that we do periodic flushing of that as a result of this issue. But I need to verify that.

MEMBER STETKAR: Okay.

DR. BARTON: Okay. Thanks.

Refueling canal leakage. One of your

proposed actions was to replace -- you thought these graphoil washers may be the source of the leakage.

And my question is since this condition has been going on for several years I wondered if you have replaced these washers. And if you did, has it affected your leakage rate?

MR. BYRD: We have David Chew here as our program owner.

MR. CHEW: My name is David Chew. I'm the refueling canal system engineer. We haven't done anything with the washers themselves. When we first identified the issue, we looked into using an epoxy liner in 2005 to seal the canal. We applied that at the end of the outage. When we went into the refueling outage in 2006, the liner started to de-laminate and it didn't serve its purpose, so we were going forward. We thought maybe it was a condition we didn't apply the liner correctly. So in the next refueling outage we had a corrective action established to reline the system, or the refueling canal.

Based on -- in that time frame we found some operating experience that the epoxy we were using in the industry wouldn't hold up. So since then I've been working as a system engineer. We've been doing some research in the industry, looking at operating experience. And I've developed a plan based off of Prairie Island's. And we're going to cap and seal-weld all of those nuts. And we're also going to seal-weld along all the penetrations in the refueling canal coming up in 2014, our 18th refueling outage.

DR. BARTON: Okay. Thank you.

MR. CUSTER: I believe Mr. Henline has something to add to that.

CHAIRMAN SIEBER: All right.

MR. HENLINE: I've got a response for your previous question, John, about the silting that was observed in the service water system. We have a PM that every outage we open the valve to flush that system and that commitment's in line with Generic Letter 89-13.

DR. BARTON: Thank you.

MR. HENLINE: You're welcome.

MR. CUSTER: Thank you, Trent.

DR. BARTON: One other one. Maintenance Rule inspection. This goes back a ways. You noted there were some areas indicating concrete spalling on the shield building. And we didn't talk about that when went through the shield building earlier. There was a maintenance order pending repair of the spalled concrete. And was that repaired, or do you still have that problem, or --

MR. CUSTER: Let Jon Hook answer that question.

MR. HOOK: Jon Hook, design engineering manager. The areas that you're referring to were the spalled concrete that's directly above the original construction opening. During the original construction they -- part of the pour-back for that area there are imbedded pipes to allow the concrete to be injected in that area. And so there's been some surface spalling in that. We've identified that.

Now, part of our corrective actions for the shield building painting is to repair those areas.

DR. BARTON: Okay.

MR. HOOK: And that has already been done.

DR. BARTON: Thank you. That's all I've got, Jack.

CHAIRMAN SIEBER: Okay. Harold, do you have any questions? Harold?

MEMBER RAY: No, I have none.

CHAIRMAN SIEBER: Sam?

MEMBER ARMIJO: No.

CHAIRMAN SIEBER: Okay. Well, it's pretty close to 12:00 and our schedule calls for the staff to go over their SER for their portion of the meeting. And I propose that we recess for lunch until 1:00.

1:30? Okay. Until 1:30. Thank you.

(Whereupon, the above-entitled matter went off the record at 11:46 a.m., and resumed at 1:28 p.m.)

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

1:28 p.m.

CHAIRMAN SIEBER: We will renew the Subcommittee meeting on Davis-Besse Nuclear Power Station license renewal application.

Again I would point out that it would appear that not everyone here has signed in on the rosters that are in the back of the room. And if you haven't done so, perhaps at the break you could do so, so we have an accurate record of who is here.

And secondly, before we begin with the staff presentation, the applicant would like to answer some questions that they had resolved during the lunch period. So I call upon the applicant to do that.

MR. HINKLE: Larry Hinkle with the Davis-Besse license renewal team.

As related to the earlier question we had on best estimate cycles, in response to RAI 4.3-9 submitted under Letter L-11-203 dated 6/17/2011, we've provided a plot of the heat-up events versus years of service. And in that plot you can see that the rate of occurrence in the last 10 years of operation has been about 1.5 cycles per year.

MEMBER STETKAR: And we'll get that from the staff directly, so thank you.

MR. CUSTER: The response to the second open question I'd like Trent Henline to speak to, please.

MR. HENLINE: Trent Henline, engineering program supervisor. I wanted to clarify the storage tank question concerning sealant. So our diesel oil storage tanks or tank does have sealant at the interface and it is raised five inches above grade. Our borated water storage tank does have a sealant around the foundation and it's raised approximately a foot above grade. Our firewater storage tank, as mentioned before, does not have sealant. It's on a sand/oil bed. It's raised approximately six inches above grade and is internally inspected every five years with the last inspection being performed in 2009.

DR. BARTON: Thank you.

CHAIRMAN SIEBER: Is that it, Cliff?

MR. CUSTER: That's all we have.

CHAIRMAN SIEBER: Okay. Thank you very much. Next I'd like to call on John Lubinski to introduce presenters for the staff.

MR. LUBINSKI: Thank you, Mr. Sieber. Appreciate it.

This afternoon I'd like to introduce our four presenters who are up at the front table. We have Brian Harris, our safety project manager; Bryce Lehman, a structural engineer, DLR; Allen Hiser, who's our senior level advisor; and Benny Jose, who's a Region III inspector. We also have other members of the staff ready to answer questions including our project manager Sam Cuadrado.

I would also like to invite the Subcommittee. There were many questions you had of the licensee this morning. If you would like the staff's perspectives on those, please ask. May not be people at the table. People in the audience may be able to address and provide some further information. And there are a couple of issues that may not show up in the slides, but we'll be responding to your questions this morning in a more proactive manner with respect to some of those.

So with that, I'd like to turn it over t Brian.

CHAIRMAN SIEBER: Okay. Thank you.

MR. HARRIS: Thank you, John. My name is Brian Harris. I'm the safety project manager of the Davis-Besse license renewal application.

So I'll begin by providing a brief overview of the LRA and the staff's review, and I'll discuss section 2 of the SER. Then I'll turn it over to Mr. Benny Jose, the Region III inspector who will discuss his license renewal inspection. Then I'll discuss sections 3 and 4 of the SER.

So this is a slide that was mentioned earlier that we'll skip because the applicant has already given you the background information to.

So we'll go to the next slide, please. NRC review teams conducted two audits and one regional inspection at the Davis-Besse Nuclear Power site during the periods listed on the slide here. The staff started the on-site review with the scoping and screening methodology audit towards the end of January, the aging management program audits in mid-February. Region III conducts its inspections in April and May, 2011 to review Davis-Besse scoping and screening of the aging management programs. An addition week of regional inspections were held in August of 2011 to review the differences associated with Revisions 1 and 2 of the GALL report and the applicant's license renewal application.

So moving onto section 2 of the SER, section 2 discusses structures and components subject to aging management review, which is shown on this slide.

Next slide. During the scoping and screening methodology audit the staff's review resulted in additional SSCs being included within the scope of license renewal in accordance with 10 C.F.R. 54.4(a)(2). The applicant took appropriate actions to evaluate additional SSCs which were then included into the scope of license renewal. Based on review of the LRA and additional information submitted as a result of requests for additional information, the staff concluded that the applicant's methodology is consistent with the requirements of 10 C.F.R. 54.4 and 54.21(a)(1).

I'll turn it over to Benny Jose, Region III inspection team leader who will now discuss the results of his inspection.

MR. JOSE: I'm Benny Jose. I was the lead inspector for the 71002 inspection that we did during April, May and August time.

During the April-May inspections we started off with scoping and screening. And overall the scoping and screening were acceptable, however, we did -- our inspections did result in changes to the -- a few changes to the license renewal application. I will give you a few examples here.

Some of the out-of-scope systems and non-safety-related systems were -- in their application were not clarified to say why they were not -- why they were truly out of scope. For example, demineralizer system, control rod drive system, you would think they would -- you know, there are several demineralizer systems and also control rod drive system has a pressure boundary function. So the clarification was to add the pressure retaining components of those systems will be in license renewal scope.

There was another open item for -- there was no license renewal -- in the license renewal application there was no age management program was assigned to head lift lugs -- head lifting lugs. So those were type of things that we identified during the scoping and screening inspections.

Moving on to the --

MEMBER STETKAR: Benny?

MR. JOSE: Yes, sir?

MEMBER STETKAR: Before you move on, I noticed reading through your inspection report comparing to a lot of the inspection reports we've seen let's say in the last couple of years or so you seem to have many more questions about scoping and screening. Is that simply because of the original vintage of this application?

MR. JOSE: No, it's the particular style the applicant used.

MEMBER STETKAR: Okay.

MR. JOSE: Like I was trying to explain the out-of-scope systems, that's one place we concentrate on --

MEMBER STETKAR: Sure.

MR. JOSE: -- are the truly out-of-scope systems. And when you see things like control rod drive system, it's out of scope. And you tend to think that's got a pressure-retaining function. You know, why is it out of scope? So they had to add clarification. So there were several instances of that. That's why we had more questions on scoping and screening.

MEMBER STETKAR: Okay. Thank you.

MR. JOSE: The aging management portion of the inspection, in the previous slides, and the licensee also alluded to this, that originally the application was submitted in August 2010 to Revision No. 1 of the GALL. And subsequently in December of 2010 NRC issued Revision 2 of the GALL. And during the NRR's inspections, as well as our first round of inspections, we also came up with several questions to the differences between Rev 1 and Rev 2.

So because of the outstanding number of RAIs, we decided to go back to re-look at some of the programs, especially seven or eight programs were completely revised. So that's the reason we had to go back in August for another week of inspection.

For the aging management programs, at the time we did the inspection there were 40 aging management programs the licensee had, and we sampled 28 of them. And how we sample or how we select those programs is based on what we look at to see if they are a new program or an existing program, or you know, is it consistent -- you know, looking through that application we can figure out whether it's really consistent with GALL or does it have exceptions identified? And programs -- some programs are controlled by other regulations like ISI programs. So we tend to not look at those because we will be going back during our next phase to look at those. So that's the reason we selected 28 of the programs that we looked at. Again, examples, like above-ground steel tanks, air quality monitoring systems, boron monitoring. Those are some examples of those. After the inspection they added three more programs. That's why I keep bringing that up we had 40 programs at the time.

Based on our inspection there were several license renewal application as well as amendments to the application as well as the -- some program procedure changes. To give you some flavor of that, for example, the electrical cables and connections not subjected to 10 C.F.R. 50 -- you know, 49. The cables that are in localized -- adverse localized alignments. The GALL required that they looked at all the cables, they inspected all the cables, but the application said the applicant said they will do a representative sample. So we questioned that. So they had to revise the LRA to include that. External surfaces monitoring, you know, there were specific acceptance criteria involved in Rev 2 that you have to inspect components once per fuel cycle. So licensee went about and made changes. And in response to our questions, they did not take out specific commitments, but they did have a local database called an open item number. Several open item numbers were open based on our inspection.

Fuel oil chemistry program also had a requirement to look for microbiological activity once ever quarter, that the licensee has taken an action to do that. These are a few examples, or several more examples.

Next slide, please. Okay. Now coming to the results. We said before the scoping of SSCs, we did not find any adverse problems, so we did find them to be acceptable with the changes that we brought about. And the documentation supporting the application was audit-able under the rule, and those were all reports, 2010-10 and 2011-12. Those were two reports that we documented our inspections results.

Any additional questions for me?

(No response.)

MR. JOSE: In addition, some of the discussion this morning, we could look to some additional information. I would invite my branch chief Ann Marie to talk about the intake now. We have some additional information on that.

MS. STONE: Yes, good afternoon. My name is Ann Marie Stone. I'm the branch chief in Region III.

I am responsible for license renewal and also responsible for the ultimate heat sink inspections and the component design basis inspections.

In July 2011, during the ultimate heat sink inspection, my inspectors walked down -- and I also walked down the intake canal. We were able to get, you know, our eyes on the situation.

There's actually two issues with the intake canal. The first is a slope issue. The slope of the walls are not in accordance with the licensing regs and so they are operable but non-conforming with the license. So that is something that the licensee has to fix. But that's already in the Part 50 as a Part 50 requirement.

The other is, as the licensee, or as the applicant has talked about, is two areas that are actually sinking. It's not that this material slid into the intake canal. It appears that it's just sinking down. And that again is something that they have had contractors -- as they talked about, contractors take a look at that. We as a regional office looked at it from an operability standpoint and we believe that -- again that it is operable, but in a non-conforming condition. We also --

CHAIRMAN SIEBER: Are there --

MS. STONE: I'm sorry?

CHAIRMAN SIEBER: Are there any active mines in the area? I know that further east they mine salt along the Lake Erie shores. Are you aware of --

MS. STONE: I am not --

CHAIRMAN SIEBER: -- anything that's going on sub-surface?

MS. STONE: I am not aware of anything. I do not have that information.

CHAIRMAN SIEBER: Okay.

MS. STONE: When my inspectors took a look at it back in July, we did ask questions with respect to were there an earthquakes, minor earthquakes, fracking, you know, anything like that going on. And there was some, but very, very minor. We're also trying to figure out what -- you know, change analysis. What is different now than it -- you know, prior to that, prior to the identification of that.

MEMBER STETKAR: Has the settling -- do you have any idea whether it's an emergent issue, or is it -- has it been occurring gradually over the 35-year life of the facility?

MS. STONE: My understanding is that the license identified it back in 2007. In 2011, as we were doing our inspection; as I said, we walked it down, our communication, our interview with the system engineer at that time was that basically it did change from 2007 to 2011. And I was actually out there back in August of this year, so I saw a slight change between 2011, 2012. My inspectors are following up on that. But at this point we're not questioning operability on the --

MEMBER STETKAR: Right, I understand.

DR. BARTON: Well, didn't this site experience any of that earthquake that went up the East Coast that North Anna felt went up into Ohio?

MEMBER STETKAR: It's too far west, I think.

DR. BARTON: It was in Ohio. I know Ohio felt some of it. I didn't know whether this site was affected or not.

CHAIRMAN SIEBER: They may have had some seismic instrument response here, but I'm not aware of that. But in the 1980s there was a seismic event further east along Lake Erie that was recordable at least 100 miles away.

MS. STONE: And I guess the other thing I'd like to just add is that I think this was an excellent example of how the license renewal for us here in headquarters as well as the license renewal and those doing Part 50 inspections. And the region worked together to come to a common understanding of what the issue is and how to proceed from a -- basically on how to fix the issue.

MR. JOSE: I would like to touch upon two more items that was brought up during the morning session.

The switchyard degradation of foundation. Our teams very specifically noticed that and asked questions of the licensee. The licensee had taken a special -- a specific open item No. 383 to either repair, evaluate the condition and evaluate the process for addressing degradative conditions in the switchyard. And that's where we left it off.

And the second issue has to do with the --

CHAIRMAN SIEBER: Yes, I'd like to ask the licensee a question there. In a lot of plants that I'm familiar with, in recent years the switchyard -- custody of the switchyard has been divided, and particularly when transmission companies differ from the operator, or the plant operating company. Is that the case at Davis-Besse? In other words, are there items in the switchyard that actually do not fall under the custody, the cognizance of the plant folks?

MR. BYRD: So to understand your question, you're asking who is responsible for the maintenance of the switchyard?

CHAIRMAN SIEBER: That's right.

MR. BYRD: So the actual work, the activities, the work activities are performed by the Western District of transmission and distribution, however, we do preventative maintenance for activities in the switchyard. In this specific case though the issue you're talking about, you know, we did some research on that. And in this particular activity, this order that was voided by the transmission and distribution apparently, you know, this was done back in 2008. And there was knowledge of that by engineering. At least the plant engineering has the responsibility for monitoring the switchyard. They were aware of that. However, we need to follow and understand how that was -- some of the other implications of voiding that order.

CHAIRMAN SIEBER: Well, is there a difference in the standards used by the switchyard -- and I'll use the word "owner" for back of a better word engineering and operating standards that differ from those that one would expect from a nuclear power plant operating equipment? In other words, is there a difference in quality level and timeliness, responsiveness and, you know, procedures and practices?

MR. BYRD: We attempt to control that by having -- first of all, we do have a -- oversight of the switchyard by our own electrical maintenance personnel. So whenever we're having switchyard work being performed, we do maintain oversight of that work with our nuclear staff. And in the case of Davis-Besse, until pretty recently the actual switchyard work was in fact performed in house. So we do have a quite of bit of knowledge in house amongst -- with that kind of activity.

CHAIRMAN SIEBER: But that's not the case today, right?

MR. BYRD: As of today that has been transitioned over to the Western District, that activity, but we do maintain oversight. Whenever they're in the yard, we have personnel in the yard maintaining oversight.

CHAIRMAN SIEBER: But it's still under the control of FirstEnergy Corporation?

MR. BYRD: That is correct.

CHAIRMAN SIEBER: Okay.

MEMBER STETKAR: Do you operate the breakers in the switchyard from the owner, or does somebody else operate the actual operation of the breakers?

MR. BYRD: The operation of the switchyards in the -- I'm sorry, breakers in the switchyard would be from the unit.

MEMBER STETKAR: From the unit?

MR. BYRD: That's correct.

MR. JOSE: The second item I wanted to talk about was a discussion about manholes and the water. And we were specifically looking at, you know, medium-voltage cables, inaccessible cables, specifically safety-related cables that went through manholes. We asked them to open up a couple of manholes and we only identified one of a few cables that were, you know, going through that particular manhole. And we did find water. So we wanted to see. So they opened it up for us. And there was water in there. And based on that, we asked our question, you know, how are you going to get rid of the water? There were actually -- it was configured as four manholes side-by-side. Two of them had sump pumps installed in them. The initial reaction or people thought that the other two manholes were supposed to drain into the two with sump pumps.

And the second round, that's why when we went back in August, we opened that and saw water was still there. It wasn't draining. So at that point they initiated a notification to engineering -- design engineering to prepare a modification package to install sump pumps. And that's also documented in our second report.

CHAIRMAN SIEBER: Okay.

MEMBER STETKAR: Benny, I forgot to ask the applicant, is the water -- do you know; and it's probably easier to ask the applicant, but because you've looked at the stuff, is it event-driven or is it groundwater? Are the bottoms of the manholes below 570 where the nominal water table is?

MR. JOSE: I don't recall the exact elevation, but it was during rainy season that we there, you know, May, June, as well as August time frame. There was rain in between. But the two of the sump pumps had -- I mean, two of the manholes did have sump pumps and the other two did not.

MEMBER STETKAR: And they're installing sump pumps or --

MR. JOSE: Right.

MEMBER STETKAR; -- or at least making sure the manholes drain to someplace that does have a sump pump?

MR. JOSE: Right. And we also noted that the sump pumps would be charging right next to the sump pits. It's true. It pumps right back into that. I mean, that's -- well, it could be sealed, too. But the modification was supposed to have those things extended out also.

CHAIRMAN SIEBER: And the ones where sump pumps were dry?

MR. JOSE: Yes.

CHAIRMAN SIEBER: Okay. So they were operating the sump pumps?

MR. JOSE: Yes.

DR. BARTON: I don't remember. Were the cables actually submerged?

MR. JOSE: The cable was, yes. The 141-60 cable, yes.

With that, I'll turn over to Brian.

MR. HARRIS: All right. Thanks. Thanks, Benny.

So this slide details section 3 of the SER with the following subsection as shown on the slide here. So I won't cover each subsection, but will touch on those which either have an open item or an item of interest.

Establish and issue the SER open items of July 31st of 2012. There are four open items related to the shield building crack, operating experience, pressure-temperature limits and upper shelf energy.

There are no confirmatory items.

CHAIRMAN SIEBER: And responses to all four of these have been submitted to the staff for review?

MR. HARRIS: That is correct.

CHAIRMAN SIEBER: They're under review right now?

MR. HARRIS: Right. So we'll touch on that. In the SER the staff had an open item related to the laminar cracking in the shield building. As the applicant noted, the cracking was observed in multiple locations and the applicant concluded that the cracking was caused by rapid freezing of significant moisture driven into the concrete during an extreme blizzard of 1978. Although the root cause determined the initial cracking was event-driven, the staff believes the degradation could continue to grow. Therefore, it should be monitoring a period of extended operation. To address this, the applicant submitted a plant-specific AMP shield building monitoring program to monitor the cracking. The staff reviewed the submittal and required additional information in order to complete its review.

Move onto the next slide. So the areas identified on this slide represent the status of the issue at the time the SER with open items was prepared.

So since that time the applicant has submitted an updated AMP and additional information which addressed some of these points and which the staff us currently reviewing.

The staff's review of the applicant's original submittal identified several areas where additional information is necessary. Specifically, the staff required additional information regarding the adequacy of crack monitoring, the proposed coating and the scope of the program. The staff asked the applicant to explain why non-destructive examination techniques were not going to be used to verify the extent of cracking of 100 percent of the accessible shield building surface.

As the applicant noted in its presentation, it has since completed impulse response mapping of the entire accessible surface.

The staff also requested more information on how selected core bores would adequately represent the cracked areas throughout the building. For the coating the staff requested more information on the adequacy of the coating that was going to be selected, how the coating would be inspected or when or if it would be reapplied.

Finally, since the root cause evaluation indicated the cracking occurred as a result of a blizzard which affected the entire site, the staff requested information on why similar cracking did not occur throughout the site and how other concrete structures within the scope of license renewal would be monitored for this type of cracking. And as noted earlier, the staff is evaluating the updated AMP and RAI responses and resolution of the open items pending completion of our review.

CHAIRMAN SIEBER: Did you get responses to each of these RAIs?

MR. HARRIS: Yes. Yes, we did.

CHAIRMAN SIEBER: Okay.

MEMBER ARMIJO: Has the staff concluded it agrees with the root cause identified by the applicant, that it was event-driven, or are you not sure?

MR. HARRIS: For that one, Bryce Lehman?

MR. LEHMAN: Yes, the Region concluded -- I mean, did an inspection of the root cause report and they concluded that it was a reasonable explanation of how the cracking occurred. And I think our focus is also on -- in license renewal on monitoring the cracking and making sure that we understand how it's going to grow or lead to additional degradation.

MEMBER SHACK: But you've accepted the

analysis that the structural integrity is satisfactory with the extent of cracking that's now present?

MR. LEHMAN: Yes, that's correct.

CHAIRMAN SIEBER: Okay. Thank you.

MR. HARRIS: Okay. Moving onto the next slide. Open B.1.4-1 is related to the applicant's consideration of aging-related operating experience during the term of the new license. Now this issue h been discussed with the ACRS and previous subcommittees, most notably the Limerick Generating Station. During its review the staff issued the final license renewal ISG-2011-05 entitled, "Ongoing Review of Operating Experience." This writing emphasizes that operating experience is a key feedback mechanism used to ensure the continued effectiveness of the aging management programs and its activities. A summary of the operating experience review framework described in the ISG is presented on the slide here today.

In response to the staff's RAIs, the applicant has described the activities it will us to review operating experience related to aging. The staff is completing its review of these activities in accordance with the framework set forth in the Interim Staff Guidance. Resolution of this open item is pending completing of the staff's review.

Next slide, please. So section 4 of the SER contains the staff's review of time-limited aging analysis, or TLAA. TLAAs are certain plant-specific safety analyses that involved time-limited assumptions defined by the current operating term and must be listed by section 54.21(c)(1) and any plant-specific TLAA-based assumptions per 54.21(c)(2). The staff reviewed information in the LRA to determine whether the applicant has provided sufficient information pursuant to 54.21(c)(1) and (c)(2).

So open item 4.2.4-1, this addresses the methods and bases that will be used to generate the applicant's P-T limit curves for the period of extended operation when submitted in accordance with the tech spec section 5.6.4 requirements for P-T limit curve provisions. Reactor vessel extended belt line components, including nozzles will pass a neutron fluence exposure of 1 times 10 to the 17th neutrons per centimeter squared during the period of extended operation. Therefore, the applicant must consider the effects of neutron embrittlement on P-T limits for these extended belt line components.

RAI 4.2.4-1 requested the applicant to address how these extended belt line components will be considered in the P-T limits for the period of extended operation. The applicant has provided a response to this RAI and the staff is currently reviewing the response.

All right. Moving on to the next open item, open item 4.2-1 addresses the applicant's upper shelf energy calculations for the LRA. The rule requires that the USE value for ferritic components in the belt line region of the reactor vessel must be at least 50 foot-pounds at the end of the licensing operating term. This applies to the expiration of the period of extended operation for plants that have been granted license extensions based on the 60-year fluence projections for the belt line components. This is why the LRAs include TLAAs on the USE analysis. If the applicant cannot demonstrate that the end-of-life USE value for the belt line component would be greater than or equal to 50 foot-pounds, the rule allows licensees to demonstrate acceptable resistance to fractures through an equivalent margin analysis.

The applicant used a generic USE value of 70 foot-pounds for the Linde 80 reactor vessel welds to project the USE for the period of extended operation. The staff did not find this approach acceptable because the 70 foot-pound values represents an average taken from generic Charpy impact data for Linde welds, for

80 -- Linde 80 welds. The use of an average value is not a conservative approach as opposed to, for example, a lower bounding or a mean minus two standard deviation value.

In lieu of justifying that the 70 foot-pound initial upper shelf energy the applicant's RAI response includes an equivalent margins analysis for the Linde 80 welds. The staff is currently reviewing these analyses to determine whether they meet the regulatory requirements of 10 C.F.R. Part 50 Appendix G for the period of extended operation.

MEMBER SHACK: When you're dealing with something like this where you don't have data on the specific weld, would you accept the lowest value if the mean minus two standard deviations was lower?

MR. HARRIS: Dr. Hiser, would you --

MEMBER SHACK: I mean, this is -- you know, it's a question of sample-bound versus population-bound there.

DR. HISER: Yes, I guess a short answer is it's case-dependent. I mean, we would have to look at all of the data and the justification. In general, I think that probably is something that we would find favor with, using the lowest value.

MEMBER SHACK: Oh, using the lowest value?

Even if the mean minus two is lower?

DR. HISER: We'd have to look at all the data. I mean, again, if it's three data points, then that might create a difficulty. But in this case they were able to us copper fluence correlation for fracture toughness to do the EMA. So the --

MEMBER SHACK: Yes.

DR. HISER: -- initial upper shelf energy --

MEMBER SHACK: Becomes a moot point, right. Well, I guess I just don't see why you'd find that acceptable. I mean, why would I take a sample-bound rather than population-bound?

DR. HISER: As I said, it would be case-by-case. I think in general we do like --

MEMBER SHACK: I'll be asking this question quite often.

MR. HARRIS: The SER also included on proposed license condition related to inspecting inaccessible portions of the steel containment vessel. The applicant has operating experience with minor borated water leakage migrating through concrete structures inside of containment. Due to the configuration of the containment there is a slight possibility that borated water leakage has gathered in inaccessible areas at the bottom of the steel containment vessel. If the water is in contact with the vessel, it could cause corrosion which would remain undetected during the period of extended operation.

To address this concern staff has proposed a license condition requiring the applicant to remove concrete from a low point of the containment in order to inspect the inside surface of the containment vessel. If leakage is not successfully stopped or if the initial inspection identifies water, the inspection will be repeated during the period of extended operation. These inspections will provide reasonable assurance that any degradation to the imbedded portions of the containment vessel will be identified. The staff believes this issue is appropriate as a license condition because it affects containment, and without these inspections the areas identified would not normally be inspected. It is possible that the degradation of the containment vessel could be occurring without an adequate method of detection.

MEMBER STETKAR: Brian, before you switch slides, I have a couple of questions. The first one is; and we asked the applicant, this -- as I understand it, they're going to take their core bore at a location that's about 30 inches above bottom dead center of the reactor -- of the containment shell. How does an inspection at that location provide confidence that indeed you have not had a fairly large area of boric-acid-containing water in contact with that steel shelf within that 30-inch-deep hemisphere? Or -- it's not a hemisphere, but --

MR. HARRIS: Bryce, do you have --

MR. LEHMAN: Yes, I think -- I mean, you're right they're not taking it from the --

MEMBER STETKAR: I mean, you know, I could look at the side of the -- vertical side of the containment also and, you know, it wouldn't give me much confidence about that. So I'm really curious about what -- if you don't find anything there, what does that tell you about the status of the shell at the low point? Because if you do find something, obviously it's a problem.

MR. LEHMAN: Yes. Here's where they're proposing to take the cores. So even that I think was about 30-inch delta there.

MEMBER STETKAR: That's what it said in the SER, yes.

MR. LEHMAN: And I guess ideally dead center would be the best, but I think we felt that this would be a good indication of -- you know if there's an issue with borated water pooling there --

MEMBER STETKAR: If there is, that's true. If there's not, how do you have confidence that indeed five inches below that area there isn't an issue? I mean, if you do find it there, that's certainly an indicator.

MR. LEHMAN: That's a good question. I think we can take that and look at it some more detail and see if it's appropriate, but I think our logic was that the odds were if it's been pooling there throughout the --

MEMBER STETKAR: We asked the applicant and they -- you know, why they weren't boring bottom dead center and they said, well, they don't want to cut a hole in their sump liner. You know, people understand how to weld, so that's okay. I'm just curious about that.

MR. LEHMAN: Yes, I think that's a good question. We can take that and look at it in more detail.

MEMBER STETKAR: And since you have this nice picture here, I'm going to come back to my groundwater question, the staff has basically accepted the applicant's program that says, well, we're going to make sure that the drains in the sand pocket area are open. We're going to -- if we can collect any water from those drains, we're going to monitor that water for chemistry, as I understand it. And, you know, we'll inspect the area that's accessible there at the interface. How does that give us confidence that we don't have corrosion from the exterior of the shell bottom dead center?

MR. LEHMAN: Following up on what we just discussed, I think that's a good point. We'll take it as feedback and go back and look at it. But they do have a commitment to take UT measurements at the five locations where they've seen the groundwater coming into the sand region.

MEMBER STETKAR: But that's way up --

MR. LEHMAN: That's right.

MEMBER STETKAR: -- and that's way up at the interface there.

MR. LEHMAN: Yes, I thought we had the closeup of that area.

MEMBER STETKAR: We have handouts that show that actually.

MR. LEHMAN: Okay. Okay.

MEMBER STETKAR: But again, in some sense that's relatively high. It's still below groundwater level, I guess, depending on where you are, but it's still relatively high in elevation.

MR. LEHMAN: And that's correct. But I guess there we'll have he -- that's where you're going to see the wetting and drying and replenishment of oxygen in that area.

MEMBER STETKAR: You're relying on the argument that it's a low-oxygen environment and not conducive to corrosion.

MR. LEHMAN: That's part of it, but then also the other -- the license condition we'll be -- they'll be doing UTs from the inside which would identify degradation.

MEMBER STETKAR: That's certainly -- yes, I mean, the 30-inch area is certainly below the groundwater level, so that should -- that one, regardless of where they do that bore, ought to give them some indication.

MR. LEHMAN: Yes.

MEMBER STETKAR: Okay. I was just curious because you were so active in following on the boric acid corrosion, you know, having a license condition for them to do a core bore from the inside, you seem to pretty much accept the groundwater issue from the exterior.

MR. LEHMAN: But again, I think that license condition, it wasn't laid out that way in the

SER, but that does support --

MEMBER STETKAR: Yes, it does.

MR. LEHMAN: -- with the UT measurements, yes.

MEMBER STETKAR: Thanks.

MR. HARRIS: Any other questions while this slide is up, or should I go back?

(No response.)

MR. HARRIS: Yes, I guess before we get to the conclusions, there were a few items of interest in this morning's session. And if I can have Bill Holston from the staff come forward and discuss --

MR. HOLSTON: Bill Holston from the DLR staff. There were two open questions on areas that I have oversight on, buried piping and underground tanks. The question was whether their program was consistent with GALL Rev 3. And I had verified that during the process of evaluating the LRA --

DR. BARTON: We only have 2 on GALL, I think.

MR. HOLSTON: Say again?

DR. BARTON: We only have 2 on GALL, I think.

MR. HOLSTON: What did I say?

DR. BARTON: You said Rev 3.

MR. HOLSTON: Sorry. Rev 2.

DR. BARTON: No wonder none of this makes sense, you know? I'm going to spin my head around a few more times if there's another one out.

MR. HOLSTON: So, yes, it is consistent with Rev 2 of the GALL, and I believe that's the only outstanding question on the buried piping.

On the above-ground tanks program --

MEMBER SHACK: No, no, no, no, no.

MR. HOLSTON: Okay. Sorry.

MEMBER SHACK: Why not make it consistent with the ISG?

MR. HOLSTON: With the ISG we will be evaluating that, and so --

MEMBER SHACK: It's 03. You're making them consistent with 05.

MR. HOLSTON: Correct. Yes, the ISG, we need to look at -- there are several plants we have to look at that are currently in process. The ISG just got issued, you know, right in August. So we'll be doing that and issuing it -- as necessary, issuing separate RAIs. This suspects several claims will have RAIs, but we need to talk that over with DLR management.

Any other questions on buried pipe?

(No response.)

MR. HOLSTON: Okay. On above-ground tanks, the diesel fuel storage tank was a tank that had -- in 2002 had some degradation that was noted that was repaired at that time. In 2008, they did a follow-up examination. They just found minor chips in the painting that, you know, could have been just some -- from some mechanical damage, but no further evidence of corrosion in that area.

And then other question of course was the GALL Rev 2 question, and the above-ground tanks program was consistent with GALL Rev 2.

Any other questions on the above-ground tanks program?

DR. BARTON: Thank you. No.

MR. HOWARD: Thank you, Bill.

MR. HARRIS: And also I would like to have Bryce add a few items towards the groundwater issue as discussed this morning.

MR. LEHMAN: Yes, I guess there was also a question about the sampling of the groundwater for aggressiveness. I should have addressed that earlier.

I went back and looked at the SER when we were discussing it earlier this morning and it's clear that it's unclear in the SER that the staff was -- we knew when we were reviewing it that their enhancement was sampling raw water, but I think the wording does -- is confusing, so we'll definitely go back and take a look at straightening that out. But I think the key with the aging management was that they had admitted from the very beginning that they had aggressive groundwater, so there wasn't an issue with continuing to sample to prove whether or not it was aggressive. They were assuming it was aggressive moving forward. And to address that they were suggesting a one-time inspection, basically with two core bores from the locations of known groundwater leakage.

MEMBER STETKAR: And also opportunistic, as I understand it.

MR. LEHMAN: Yes. Yes, the opportunistic. That's correct.

MEMBER STETKAR: Okay.

MR. LEHMAN: So, does that kind of answer the question a little bit?

MEMBER STETKAR: Yes, it does. I mean, I was -- I did get confused because it said well water. And I thought, well, maybe their groundwater is mostly Lake Erie or something like that. But that clears it up. Thank you.

MR. HARRIS: All right. Thank you, Bryce.

And lastly, getting back to the upper shelf energy --

DR. HISER: I want another crack at that answer. In the distribution of data, for the lower bound to be below the lowest data point with any reasonably sized data set, the deviations have to be on the high side. So if I have real high values that are skewing the standard deviation to be very large, that's probably about the only case where you would end up with the mean minus two sigma being below all of the data. And we went through a case with another plant recently on license renewal where they actually were mixing upper shelf data with some transition data and had a very high deviation, standard deviation. I guess I'd fall back to my first answer that it would be case-by-case, but I think that would be the kind of thing that we would want to look at as we evaluate each individual data set.

MEMBER SHACK: Well, I can understand you might want to understand whether the data looked normal that you distributed or not, but I've sort of convinced myself that it would be normally distributed. I still don't see why I wouldn't take the two sigma answer over the sample lower bound.

DR. HISER: I don't know, Jeff Poehler, do you have any thoughts on that from the PE perspective?

Mean minus two sigma versus the lowest value?

MR. POEHLER: Jeff Poehler, senior materials engineer in the Vessel Integrity Branch in Division of Engineering.

I don't really have any input other than yours. I think -- I mean, going back to -- the question was -- I'm not -- I think the question was --

MEMBER SHACK: My question is when I'm dealing with a population and I'm dealing with a sample, how do I choose a population bound? And you gave me two answers. And I didn't like one of them.

MR. POEHLER: Well, I think Dr. Hiser's answer was a good one. I think -- I mean, normally -- you know, normally the two sigma is not going to be below the --

MEMBER SHACK: Well --

MR. POEHLER: -- middle of the data set, but --

MEMBER SHACK: I mean, I always just think we ought to be keeping in mind that we're generally thinking about looking for populations from samples. And as long as you take that into consideration when you come up with the answer, I'm fine. But I've seen too many people draw a lower bound between the lowest data point they happen to have at the moment, and that just sort of doesn't fly.

MR. POEHLER: Well, I guess as Dr. Hiser said, we would have to look at each case individually, but we would have to make sure that the value we picked really was conservative.

MEMBER SHACK: Well, with an EMA, there's no --

MR. POEHLER: And it -- yes, exactly. At any rate --

MEMBER SHACK: It's moot.

MR. POEHLER: At any rate, it's not an issue for this one, so --

MR. HARRIS: Thank you. The staff's conclusion will be documented in the final SER. On the basis of its review and pending satisfactory resolution of the open items, the staff will be able to determine that the requirements of 10 C.F.R. 54.29(a) have been met for the renewal of Davis-Besse Nuclear Power Station operating license.

This concludes our presentation.

CHAIRMAN SIEBER: Okay. Do you require any additional information at this point from the applicant with the SER?

MR. HARRIS: We are in the process of reviewing --

CHAIRMAN SIEBER: Okay. So you don't --

MR. HARRIS: -- responses to --

CHAIRMAN SIEBER: You don't know whether you need more information or not?

MR. HARRIS: That is correct.

CHAIRMAN SIEBER: Okay.

MR. HARRIS: So we are in that process of reviewing those RAI responses at this time.

CHAIRMAN SIEBER: Okay. But right now the applicant is up to date with responses so far?

MR. HARRIS: That is correct.

CHAIRMAN SIEBER: Okay. Well, thank you very much. Appreciate it.

MEMBER STETKAR: Actually I have a question for Allen only because I can't not ask him a question at one of these things.

In the small bore piping --

DR. HISER: Yes?

MEMBER STETKAR: -- program the applicant's operating experience listed two failures. And I'm fine. There was one -- there was drain line weld failure, which is not something that we're particularly interested in, I think, because they do monitor it and they've done weld overlays.

The other one that caught my attention; and

I've just lost the page here, was a failure of -- it says that a metal pipe in the reactor vessel closure gasket leakage monitoring line. Applicant performed an evaluation and determined it was stress-corrosion cracking mainly caused by chloride residue left after water evaporated in the line. Their solution was they replaced the line and they now drain and flush the line after it's used to eliminate chloride residue. And the determination was, well, they basically fixed the problem, so therefore it's not relevant going forward.

How did they get chlorides in that line? Did you ask at all? I mean, I wouldn't expect chlorides to be in a vessel head leak-off drain line unless it came from the vessel.

MR. HARRIS: Yes, Bart Fu is --

MR. FU: I didn't quite get your question.

MEMBER STETKAR: Okay. There is -- I'm reading from the SER. It says discussing the failure. In the first case the applicant detected a crack in the pipe metal in the reactor vessel closure gasket leakage monitoring line --

MR. FU: Right.

MEMBER STETKAR: -- during an inspection in 2002. The applicant performed an evaluation and determined that it was stress corrosion cracking mainly caused by chloride residue left after water evaporated in the line.

My question is how did you get chlorides in that leakage monitoring line unless it came from the reactor coolant system, which is somewhat troublesome?

MR. FU: You're probably right. You know, they used the line mainly during the outage. But based on the OE, my understanding is when you left some of the remaining water in it and then through operation it could vaporize. And then whatever, you know, residual that got left there, maybe there's some concentration. That's what we understand of the OE. And then the concentration could be a chloride or some induced stress corrosion factor.

MS. GALLOWAY: Does the applicant have any further information on that?

MEMBER STETKAR: Thanks.

MR. HOFELICH: I'm Jake Hofelich. I'm the ISI program owner.

The issue with the line is when we flooded up the refueling canal and when we drained it out after refueling, we didn't drain this line. So the line was full of the refueling canal water and when it dried up, it concentrated the chlorides at the bottom of it and caused the cracking.

MEMBER STETKAR: Where's the chlorides in that water coming from? That's supposed to be really nice clean water.

CHAIRMAN SIEBER: Yes, because that has a steel liner presumably.

MR. DAWSON: Alvin Dawson, chemistry manager at Davis-Besse. I can tell you that we analyze for chlorides in all conditions and -- all conditions in the system, both in the reactor cooling system and in the fueling canal, and at no time do we have chlorides that exceeded our limits, which are less than our tech spec limits. So it -- I can't -- that's all I can speak to, is that we don't -- we wouldn't not have -- we did not have any chlorides that exceeded our limits, which are less than the tech spec limits.

MEMBER STETKAR: Do you think this was an accumulation over time just basically because water evaporating in that line --

MR. DAWSON: At first glance it would appear to be so.

MEMBER STETKAR: Okay.

MEMBER ARMIJO: Was that actually measured chloride, or was that just somebody saw some deposits and said that must have been chloride?

MEMBER SHACK: They saw a crack and said it must be chloride.

DR. HISER: This is a concern we've had going back to Calvert Cliffs, the very first license renewal application, and this was the position that we -- I think they may have had the same operating experience with cracking, and that was where we'd established the position that flushing the line after refueling outages would help to eliminate any contaminants and eliminate the crack concern. So I think it -- I don't know --

MEMBER STETKAR: This predates my time, so -- and this is my first chance --

DR. HISER: But I think the conclusion at that point was that it was accumulation over a number of refueling cycles where they would have water in there, it would flask to steam, leave deposits and just would slowly accumulate to a level that could cause cracking.

MEMBER STETKAR: Thanks.

MR. FU: Oh, I just want to elaborate a little bit. Since that OE, I think during the review we asked some specific items, like Limerick, from then on Grand Gulf, you know, make sure they include it in the aging management program. You know, and the -- based on the OE what specific procedures do they have, like, you know, drain line during the outage, things like that. And we learned from the OE.

MEMBER STETKAR: Thank you.

CHAIRMAN SIEBER: Do any of the Subcommittee Members have questions they would like to ask? John, you usually do. Do you have any additional questions?

MEMBER STETKAR: No, I'm pretty happy now. I asked Allen a question.

CHAIRMAN SIEBER: Okay. Bill?

MEMBER SHACK: No, Jack.

MEMBER ARMIJO: Yes, I'm still perplexed with our root cause on your shield building cracking. I think it doesn't explain a lot of the observations and I wonder why the staff has agreed that it's event-driven versus design-driven. But I'm looking forward to reading the report that the applicant's going to send me. I think the important thing is that the conclusion is that that building is structurally sound. That's a more important thing. I agree with that. But what bothers me is that if you don't really nail the root cause, you may not fix the problem. And, you know, I think that what's being done is a good thing to do, but not necessarily the root cause of the problem.

DR. HISER: Yes, I think from the

perspective of the license renewal review we use things like that that are part of the current licensing basis. And if the staff has made a determination of what's acceptable, then we just go forward with that looking at the condition and likely degradation would occur up to PEO and then during PEO and ensure adequate aging after that.

MEMBER ARMIJO: Yes, and I think --

DR. HISER: We don't question that decision.

MR. LUBINSKI: If I could basically add is in looking, as we said -- number one, this is an open item and we appreciate the input today. And I think what's important, as you said, is we have made a determination today, or I should say the licensee has made a determination it's structurally sound, and we agree with that.

In moving forward, if it's structurally sound today, we need to, as part of our aging management programs, have the licensee monitor moving forward the condition. And that's one of the key points that we did have in our open item and asking questions. And we are going to be reviewing moving forward so that we can still make that same determination during the extended period of operation.

From a Part 50 standpoint, as Ann Marie Stone said, we do coordinate these issues very close, whether it's a Part 50 issue or Part 54 issue. So this is not something where we're just waiting until the extended period for operation. We will be continuing to look at this during the current 40 years as well.

MS. GALLOWAY: And just to clarify a little bit further, too, we don't just accept blindly the outcome of root cause analyses. There are other pieces of information that might come about as part of the Part 50 review. To the extent that we need to have an understanding to appropriately define and have reasonable assurance of the aging management programs in the PEO, we do need to assure ourselves that the correct starting point is being established in order to have that determination appropriately defined for the PEO.

I think Bryce did indicate that we had also looked at the root cause evaluation and we felt comfortable that it was appropriate and that we could use that then as a basis to define that aging management program.

MEMBER ARMIJO: Yes, well, you know, the point I'm trying to make is if after everything you do; the painting, the ceiling, and in your future monitoring you see those cracks are still growing, that meant you didn't get the root cause because the event didn't happen. The water doesn't get through there anymore. So that means it must have been some other root cause. My opinion is it was simpler than the one that's been proposed, and it still won't do any harm. But, you know, there could be situations where if you don't nail the root cause very well, you put a fix in that doesn't really fix anything and you find out after a long time.

MR. LUBINSKI: We appreciate those insights and as we move forward looking at this open item, we will be considering that. And just in a general statement, as -- if a licensee were to put in a -- you know, based on root cause what they looked at as corrective actions and in your example here, if the cracks were to go, we would be back looking into determining whether or not the root cause was adequate at that point. Still could be maybe there's something else with the fix or contributing causes that we would need to look at.

MEMBER ARMIJO: Okay. Thank you.

MEMBER STETKAR: I think the important thing is, as long as the monitoring program isn't specifically designed in a way that it precludes looking for some sort of issue because it's focused too narrowly on that specific root cause, then you could have a problem. And in this case, that doesn't mean to be --

MEMBER ARMIJO: No, it's a general --

MR. LUBINSKI: At this point our questions are all on monitoring crack growth, not just on monitoring --

MEMBER ARMIJO: The effectiveness of the paint.

MR. LUBINSKI: -- the corrective action of the paint. That's correct.

CHAIRMAN SIEBER: Any additional questions, Sam? Harold, do you have any questions?

MEMBER ARMIJO: Well, I do. You know, I really would like to learn more about that containment, this water coming up through the bottom around the containment, getting up into that pocket. I've always -- that bothers me particularly that there doesn't seem to be much you can do about it.

MEMBER SHACK: Think of it as treated water, Sam. It's been filtered through concrete.

MEMBER ARMIJO: Bill, I -- that's a torture -- well, you know, I just would like to have the staff think about it a little bit more. If it's a high-chloride water coming up through that interface between the --

MEMBER SHACK: Well, that's why they need that sample with the UT working on both sides of it.

MEMBER STETKAR: And it's regardless of where they take that --

MEMBER SHACK: It will at least tell them what's going on on the exterior.

MEMBER ARMIJO: That -- you're right. If the exterior is being badly corroded, that one measurement should pick it up because it's coming up.

MEMBER STETKAR: Yes.

MEMBER ARMIJO: All right.

MEMBER STETKAR: It should be reasonably uniform and --

MEMBER ARMIJO: Anyway, next time you present, if you could get --

MR. LUBINSKI: I appreciate that. And as Bryce said, in general, looking at our conclusion, we believe today that the information we had that the open items are the only issues we had out there. We are -- we heard some very good questions this morning and the staff is going to go back and reconfirm. We still have that position with respect to those questions with respect to that issue. If we still have the same conclusion, you will be hearing more at the final Committee meeting.

CHAIRMAN SIEBER: Okay. At this point,

John Barton, do you have any questions or comments?

DR. BARTON: No, I don't have -- yes, I got some comment. I don't have any questions on the staff's presentation. I thought it was pretty good.

In looking at the root cause, you know, I went through that root cause analysis a couple times and I think that they did a real good job. And from the applicant's presentation this morning, if it's not -- if they didn't identify the root cause, then, you know, I'd be surprised. It appears to be the right root cause.

Now if Sam's water running uphill changes that, I'll stand to be corrected, but I think it was a good root cause analysis and I think the staff and the applicant made a good presentation of it this morning. So I'm satisfied with the root cause analysis of the cracking.

Generally, an overview of the application, the staff pointed out some issues this morning regarding scope issues and some questions on RAIs on what they saw. And I thought for, you know, where we were -- some of that I attributed to maybe GALL 1 and GALL 2, but wasn't too sure if that was really the issue, and I don't think it really was.

But in many -- in all the applications we received over the years, you know, I'm a little disappointed in this, in the thoroughness of the application. I am -- in recent memory can't remember so may RAIs on a section of this application that didn't change between GALL 1 and GALL 2, which is the TLAAs. There were 53 RAIs just on TLAAs, and I think that is the result of a poor job on the part of the applicant in this presentation on TLAAs. And I was disappointed. But this -- I guess that's the -- my main concern with this application.

And I know at this point issuing a license extension is not for this Subcommittee to recommend one way or the other, but I think we got some open items plus we're still looking -- the staff's still looking at the root cause.

MEMBER RAY: John, why did you say the water was running uphill?

DR. BARTON: Oh, I think that was Sam's --

MEMBER ARMIJO: No, that was referring to the containment.

MEMBER RAY: Water seeks a level, I mean, you know?

DR. BARTON: Well, it had nothing to do with the cracking. This is Sam's issues.

MEMBER ARMIJO: It's coming up through the

-- to the sand pocket.

MEMBER RAY: Yes, but I mean, the grade level's way up here.

MEMBER ARMIJO: It's not running uphill. It's --

MEMBER RAY: It's coming up the gap.

MEMBER ARMIJO: I know that.

MEMBER RAY: Okay. But it's not going uphill in the sense that --

MEMBER ARMIJO: Well, it wasn't coming in this way. That's what it is.

MEMBER RAY: No. Okay. That's fine. But it's not -- it's only coming to whatever level the groundwater level is, right? It's not migrating above the groundwater level.

MEMBER ARMIJO: I just thought that's initially whatever level the groundwater is.

MEMBER RAY: It's trying to reach the water --

MEMBER SHACK: I think it can throw a fair chunk of --

MEMBER ARMIJO: Right, I understand that.

MEMBER RAY: Oh, okay. All right. Well, I just couldn't understand the water going uphill comment.

MEMBER ARMIJO: But that had nothing to do with the root cause issue.

DR. BARTON: No, not at all.

MEMBER RAY: I didn't imagine it did.

DR. BARTON: No.

MEMBER RAY: I just thought maybe --

DR. BARTON: Wondering how water runs uphill. I'm sorry I --

MEMBER RAY: I thought it was a --

MEMBER ARMIJO: Oh, no, no, no.

MEMBER RAY: It seemed pretty obvious to me that unless the membrane has 100 percent integrity, which I don't see how it could, you're going to get water coming up there and there isn't going to be anything you're going to do to stop it.

DR. BARTON: And we know the membrane is not 100 percent. We know that.

That's all I've got, Jack.

CHAIRMAN SIEBER: Okay. Thank you very much. Again, at this point I'd like to thank both the applicant and the staff for well-done presentations and a thorough job.

I'd also invite at this time any comments from the audience if you would wish to make any.

(No response.)

CHAIRMAN SIEBER: Seeing none, I think -- and again, thank you for all of your hard work and your responses today. And this meeting is adjourned.

(Whereupon, the above-entitled matter went off the record at 2:35 p.m.)

FENOC™

Davis-Besse Nuclear Power Station
License Renewal Application

Advisory Committee on Reactor Safeguards
License Renewal Subcommittee Meeting
September 19, 2012

AGENDA

- **Introductions & Opening Remarks**
- **Background**
- **License Renewal Application Overview**
- **SER Open Item Review**
- **Summary**

Introductions

- **Barry Allen – Site Vice President**
- **Ken Byrd – Director, Site Engineering**
- **Cliff Custer – Fleet Project Manager**
- **Steve Dort – Project Lead / Coordinator**
- **License Renewal Core Team Members**
- **Aging Management Program Owners and Subject Matter Experts**

Background – Site

Davis-Besse Site

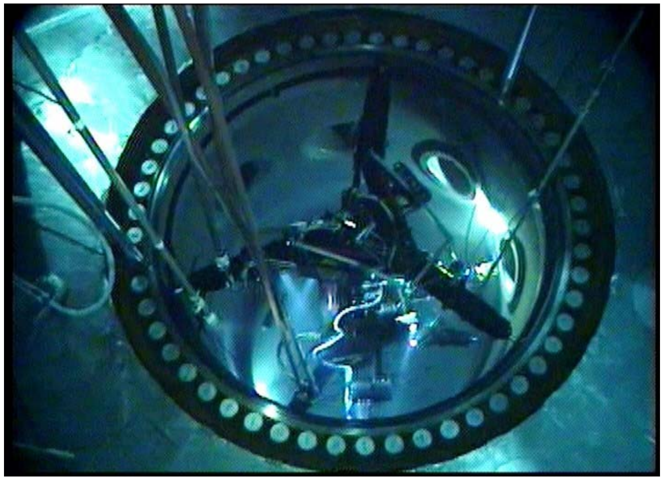
- Southwestern shore of Lake Erie in Ottawa County, Ohio
- 954 Acre Site
  - 733 acres leased to US Government as wildlife refuge
  - 221 acres for Plant structures & equipment

Background – Plant

- **Design**
  - Pressurized Water Reactor
  - Babcock & Wilcox nuclear steam supply system with raised-loop design
    - 2817 Megawatts thermal / 908 Megawatts electrical rating
    - Measurement uncertainty recapture (MUR) power up-rate of 1.6% implemented July 2008
  - Bechtel Engineering construction management
  - Facility Operating License expires April 22, 2017
- **Currently operating at 100% reactor power**
- **98 Days On-Line**

Background – Upgrades/Inspections

- **Equipment Improvements/Verifications**
  - Replaced Reactor Head
  - Replaced selected power cables
  - Replaced selected Service Water piping
  - Replaced Emergency Diesel Generator exhaust piping
  - Polar Crane upgrade and insulation replacement
  - Palfinger Crane installation
  - Completed Reactor Vessel removable core support structure Inservice Inspection – No unacceptable indications
  - Performed Integrated Leak Rate Test of Containment



License Renewal Application – Project

- **Application Development**
  - FENOC core team since 2006
  - Davis-Besse Program Owners and Subject Matter Experts
    - Development of application; audit & inspection interviews; NRC Staff conference calls; RAI responses; and, Commitment development
- **Industry Interaction**
  - NEI Working Group involvement
  - Industry Peer Review Process

License Renewal Application – Details

- **Application Details**
  - Application submitted in August 2010
  - Developed using NUREG-1801 (GALL) Revision 1
  - 43 Aging Management Programs (AMPs)
    - 12 New (4 are plant-specific)
    - 31 Existing (4 are plant-specific)
- **License Renewal Commitments**
  - 49 Commitments
  - Included in USAR Supplement (Appendix A of the LRA)
  - Managed by FENOC Commitment Tracking Program

License Renewal Application – Review

- **Audits, Inspections, and Requests for Additional Information (RAIs) based on NUREG-1801 Rev 2**
  - RAIs & responses addressed differences between GALL Rev 1 & Rev 2
  - Audit Schedule (2011)
    - Scoping & Screening — January 24-28
    - Aging Management Program Review — February 14-25
  - IP 71002 Inspection Schedule (2011)
    - Week 1 Inspection — April 25-29
    - Week 2 Inspection — May 9-13
    - Week 3 Inspection — August 22-26
  - Safety Evaluation Report w-Open Items — July 31, 2012

SER Open Item Review

- **OI 4.2.-1 Reactor Vessel (RV) Neutron Embrittlement**
- **OI 4.2.4-1 Pressure-Temperature (P-T) Limits**
- **OI B.1.4 Operating Experience (OE)**
- **OI B.2.39 Shield Building**

OI 4.2-1: RV Neutron Embrittlement

- **RV Beltline Upper-shelf Energy (USE) Evaluation**
  - Generic mean value of 70 ft-lb used to project 52 EFPY USE not statistically-conservative (mean value minus two standard deviations or lowest value)
  - Selection of lowest value resulted in 52 EFPY USE of < 50 ft-lb
  - 10 CFR 50 Appendix G requires end-of license USE to be no less than 50 ft-lb, unless it is demonstrated that lower values of USE will provide margins of safety against fracture, equivalent to those required by Appendix G of Section XI of the ASME Code
- **FENOC Response**
  - In accordance with 10 CFR 50 Appendix G, FENOC elected to qualify welds by equivalent margins analysis (EMA)

OI 4.2-1: RV Neutron Embrittlement (cont.)

- **EMA status for the RV beltline welds**
  - Nozzle Belt Forging to Bottom of RV Inlet/Outlet Nozzle Forging Welds
    - EMA submitted by letter dated June 14, 2012
  - Upper Shell Forging to Lower Shell Forging Circumferential Weld (WF-182-1)
    - EMA was addressed in the LRA
  - Nozzle Belt Forging to Upper Shell Forging Circumferential Weld <u>and</u> Lower Shell Forging to Dutchman Forging Circumferential Weld
    - EMA submitted by letter dated September 14, 2012
- **Open Item Status**
    - Response to RAI 4.2.2-4 under review by NRC

OI 4.2.4-1: P-T Limits

- **RAI 4.2.4-1 Request**
  - Describe how the P-T limit curves to be developed for use in the period of extended operation, and the methodology used to develop these curves, considered all RV materials (beltline and non-beltline) and the lowest service temperature of all ferritic RCPB materials
    - 10 CFR 50 Appendix G requires P-T Limits to be developed for all ferritic materials of reactor coolant pressure boundary (RCPB)
    - RV nozzles, penetrations & other discontinuities may exhibit significantly higher stresses that potentially result in more restrictive P-T Limits
    - Non-beltline components may have initial RT_{NDT} values that define a more restrictive lowest operating temperature

OI 4.2.4-1: P-T Limits (cont.)

- **FENOC Response**
  - Davis-Besse P-T Limits generated in accordance with 10 CFR 50 Appendix G and R.G. 1.99 Rev. 2 using methods described in approved topical report BAW-10046A
  - BAW-10046A considered all ferritic materials (beltline & non-beltline material)
    - The RV outlet nozzle, due to consideration of loading conditions, is more limiting relative to stress than any of the Class 1 ferritic branch connections (e.g., hot leg surge nozzle), the large bore RCS piping, or the primary nozzles of the steam generator

OI 4.2.4-1: P-T Limits (cont.)

- BAW-10046A considered all ferritic materials (beltline & non-beltline material) (cont.)
  - Initial RT_{NDT} of all RCPB ferritic items were considered when establishing P-T Limits and the lowest service temperature
  - Reactor vessel closure head region, outlet nozzles, and beltline region are controlling locations that regulate P-T Limits

- **Open Item Status**
  - Response to RAI 4.2.4-1 is under review by NRC

OI B.1.4: Operating Experience (OE)

- **OE review should consider aging management**
  - Interim Staff Guidance LR-ISG-2011-05 issued in March 2012
    - Address age-related degradation and aging management
    - Inform/enhance aging management programs
- **OE Program changes**
  - Revise OE and Corrective Action Programs
    - Flag aging-related OE
    - Consideration of material, environment, aging effects & mechanisms, and aging management program

OI B.1.4: Operating Experience (OE) (cont.)

- Revise OE and Corrective Action Programs (cont.)
  - Provide feedback to aging management program owners
  - Provide significant OE on aging to the industry
  - Identify training needs

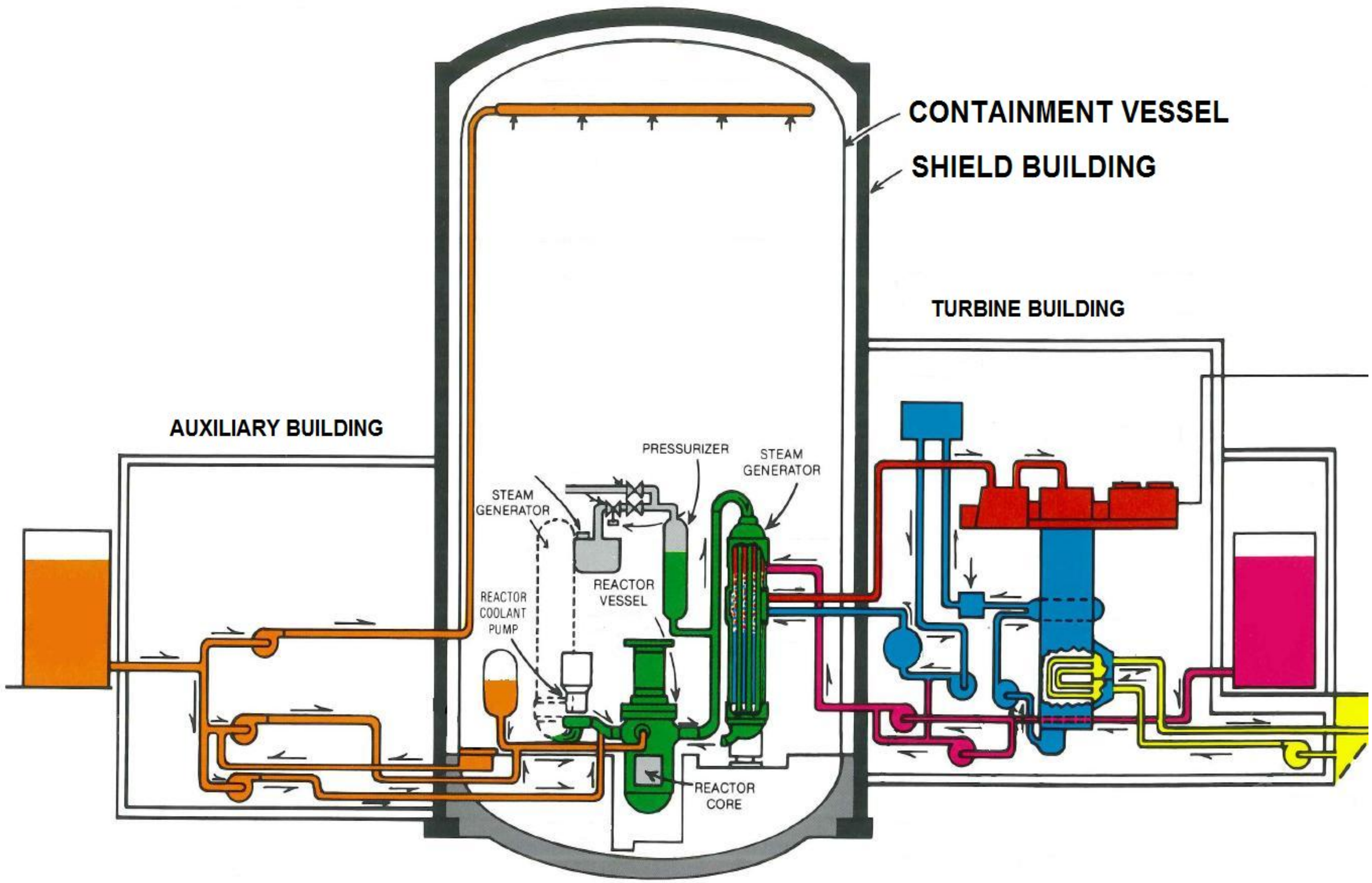
- **Aligned with LR-ISG-2011-05**
  - Responses to RAIs B.1.4-2 and B.1.4-4 are under review by NRC

OI B.2.34 Shield Building

Describe how sub-surface laminar cracking in the Shield Building will be managed for aging

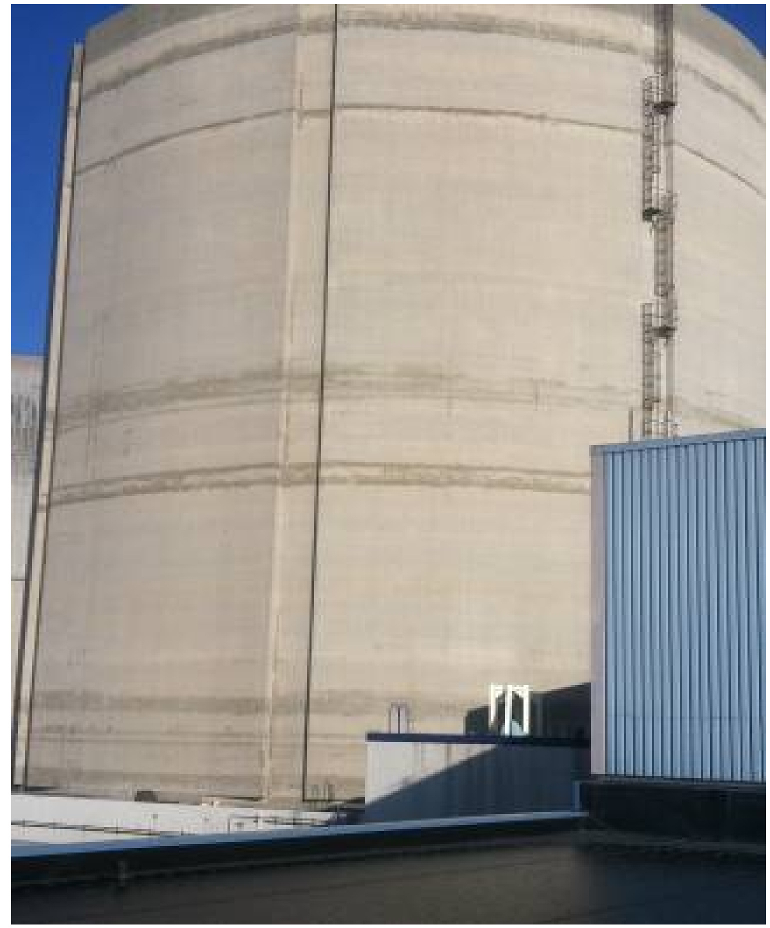
- Function & Design of Shield Building
- Discovery of Laminar Cracking
- Investigation & Extent of Condition
- Root Cause
- Corrective Actions
- Aging Management
- Open Item Status

Shield Building

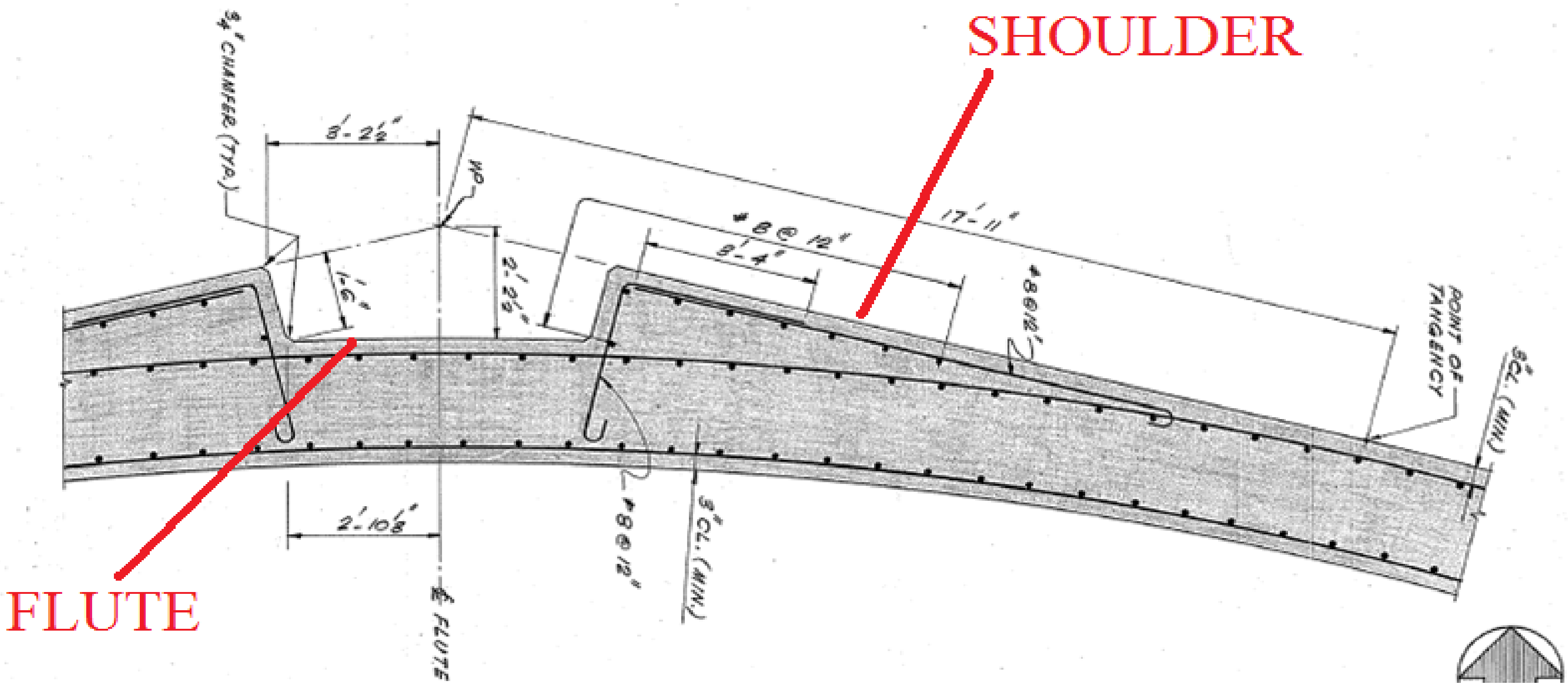


Shield Building (cont.)

- **Purpose of Shield Building**
  - Biological shielding
  - Environmental protection for Containment Vessel
  - Controlled release of Annulus atmosphere under accident conditions

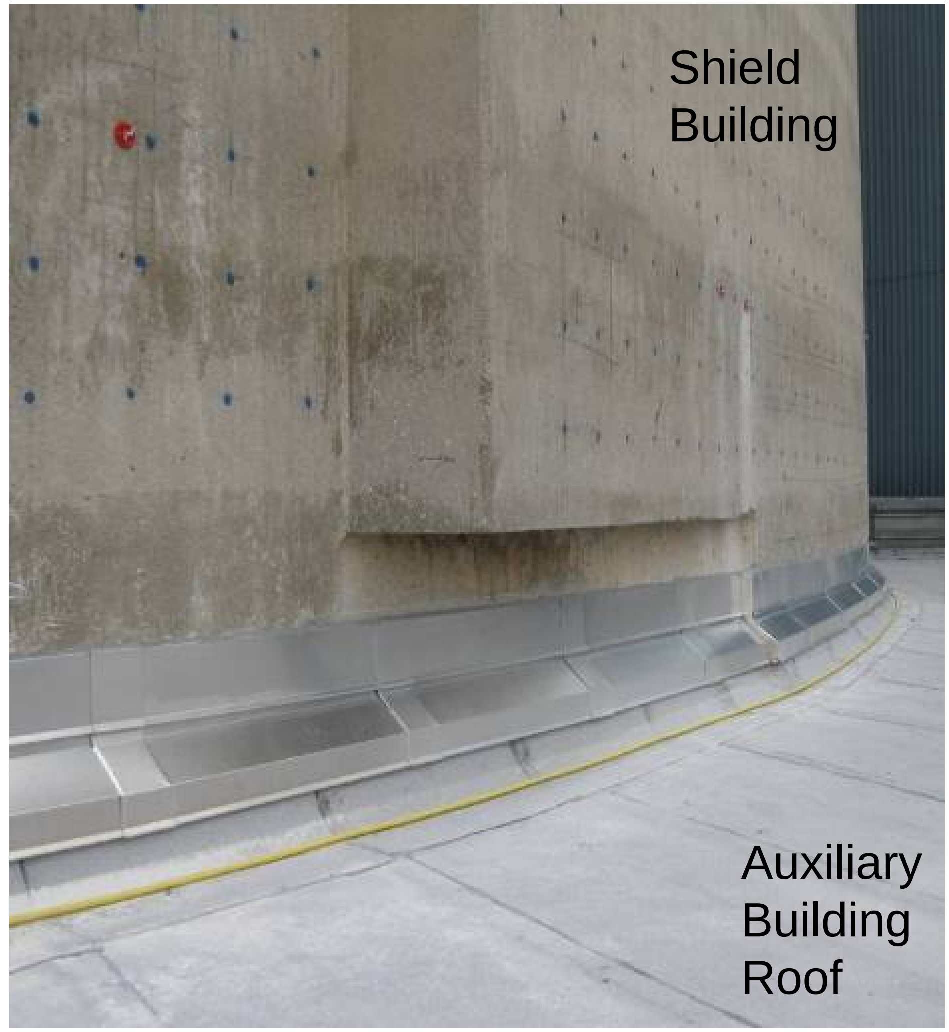


Shield Building Flutes/Shoulders



Shield Building Flute Shoulders

- **Architectural Feature**
  - The flute shoulders are a part of the Shield Building; concrete for shoulders and building shell was placed concurrently
  - Evaluation of structural capacity of Shield Building does not credit flute shoulders
  - Evaluated as a dead load in structural analysis



Discovery

- **Cracking found on October 10, 2011, during hydro-demolition**
- **NRC resident notified**
- **Condition Report written**
- **Restraint on restart established**
- **Team of experts to investigate issue mobilized**

Investigation

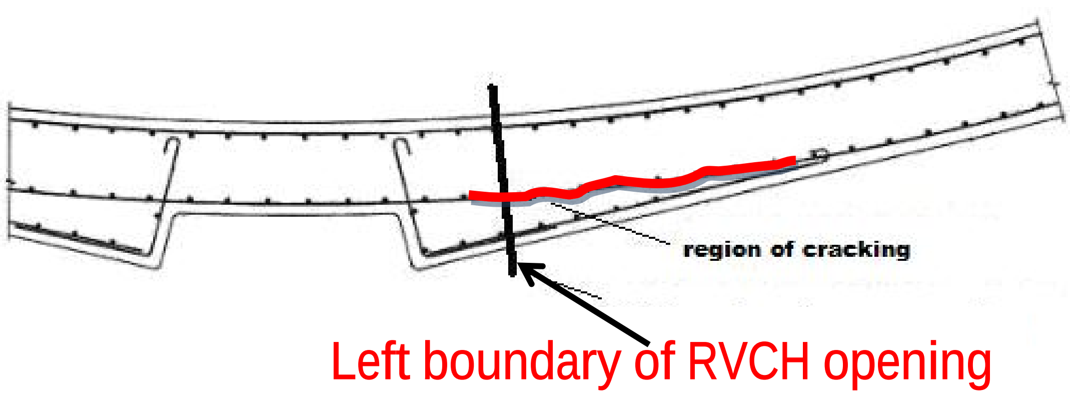
- **Impulse Response (IR) testing methodology used to investigate extent of crack**

Investigation (cont.)

- **Core bores taken to validate IR testing results, to determine crack depth and to determine crack width**
- **Investigation results were documented in the corrective action process, and the NRC was promptly notified of findings**

Summary of Shield Building Condition

- **Cracking is generic to flute shoulder regions and can be assumed to be present at any elevation in the flutes shoulders; cracking was observed to be more prevalent on the south side of the building**
- **Cracks are located near the outer reinforcing mat; no cracking observed in interior reinforcing mat**



Summary of Shield Building Condition (cont.)

- **Cracking exists at the top 20 feet of the Shield Building wall outside the flute shoulder region**
- **Two small regions adjacent to the Main Steam Line penetration have similar cracks**
  - The extent of these regions is localized and unique to these particular penetrations
- **Cracks are very tight**

Structural Evaluation

- **Original Shield Building design**
  - Building designed and constructed with significant reinforcement
  - Significant margin under design basis loads
  - Design Basis
    - Earthquake 6–6.5 on Richter magnitude scale
    - Tornado winds of 300 miles per hour
    - Tornado depressurization and missiles
- **Impact of laminar cracks on original design**
  - Potentially reduce the bond strength between concrete and reinforcing steel
  - Cracks of little impact unless reinforcing bars are spliced in the cracked region

Bounding Building Analysis

- **Bond strength of reinforcement lap splices with adjacent cracks could not be quantified and were conservatively treated as non-existent in analysis**
- **Calculations performed to provide a bounding evaluation of the effect of cracking**
  - Vertical and horizontal reinforcement assumed ineffective for strength in flute shoulders, two steam line penetration areas and in regions at top of shield building.
- **Any bond between reinforcement and concrete in crack regions provides additional margin**

Summary of Calculation Results

- **Shield Building meets strength requirements**
- **Any bond between the concrete and reinforcement in cracked regions would be an additional margin of safety**
- **Shield Building is capable of performing all safety functions with margin**

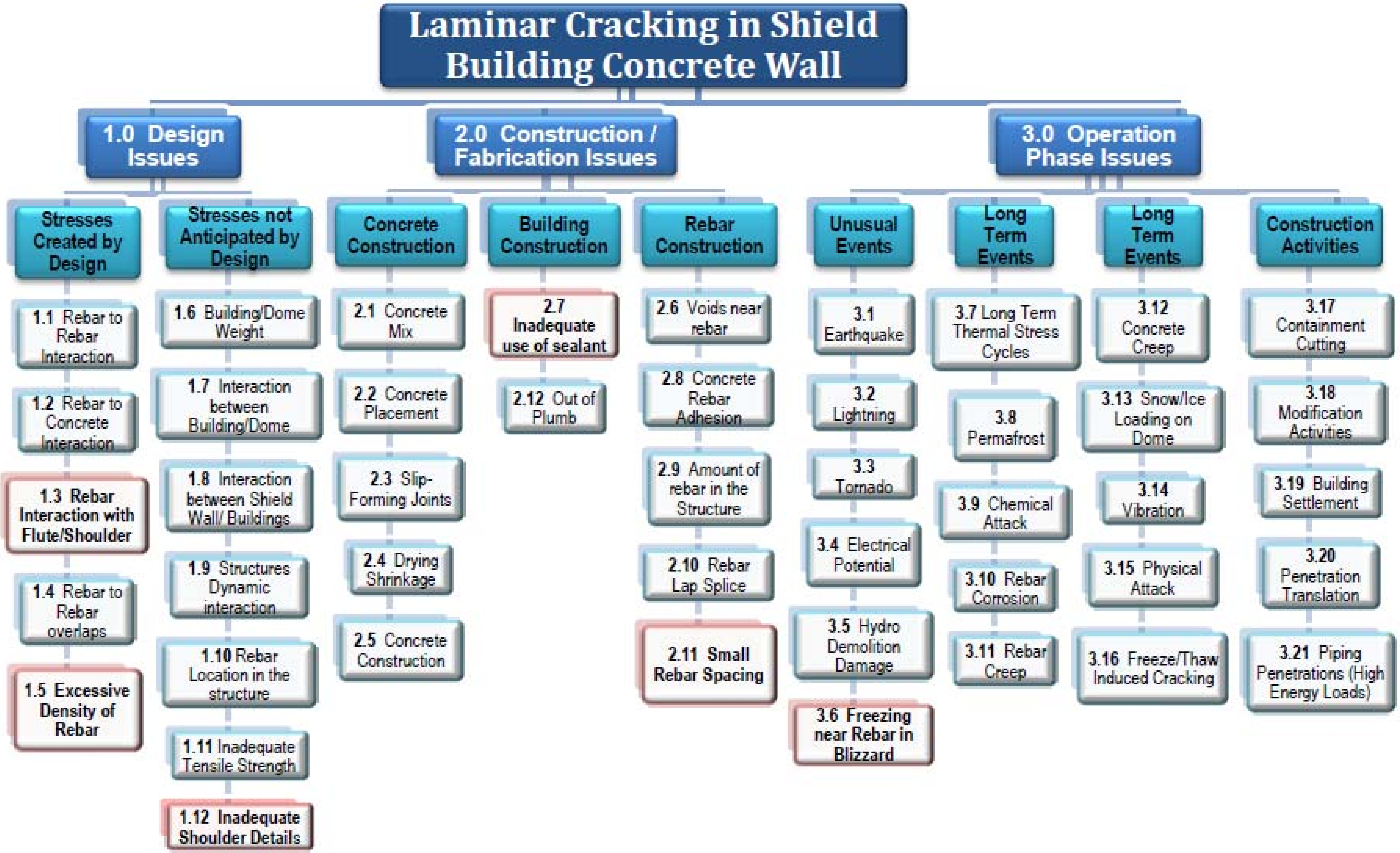
Root Cause Overview

- **Established independent team of experts**
- **Established a comprehensive Failure Modes Analysis**
- **Investigated the design, materials, construction methods, and present day operational conditions**
- **Performed concrete tests**
- **Performed analyses**
- **Identified root cause**

Root Cause Overview (cont.)

- **Performance Improvement International (PII)**
  - The PII team are experts in root cause investigation
  - Team consist of Professional Engineers, PhDs, and university professors
  - Performed more than 500 root causes
- **Industry experts as well as assistance from FENOC Engineering**
- **Followed our established and proven root cause process**

Shield Building Root Cause Fault Tree



Shield Building Concrete

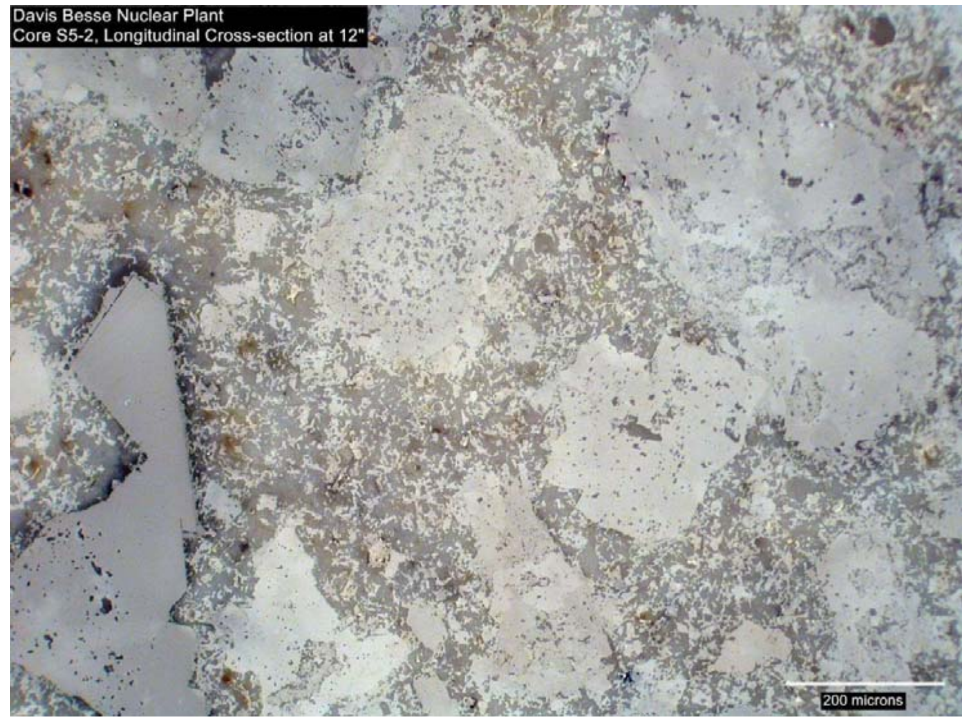
- **Concrete was subjected to a series of tests**
- **36 concrete cores from the Shield Building tested**
- **Concrete properties were determined**
- **Test results confirmed the concrete is sound and can be ruled out**

Shield Building Concrete (cont.)

- **Typical concrete sample showing the laminar crack sheared the coarse aggregate**
- **Therefore, laminar crack occurred after the concrete achieved it strength**

Shield Building Concrete (cont.)

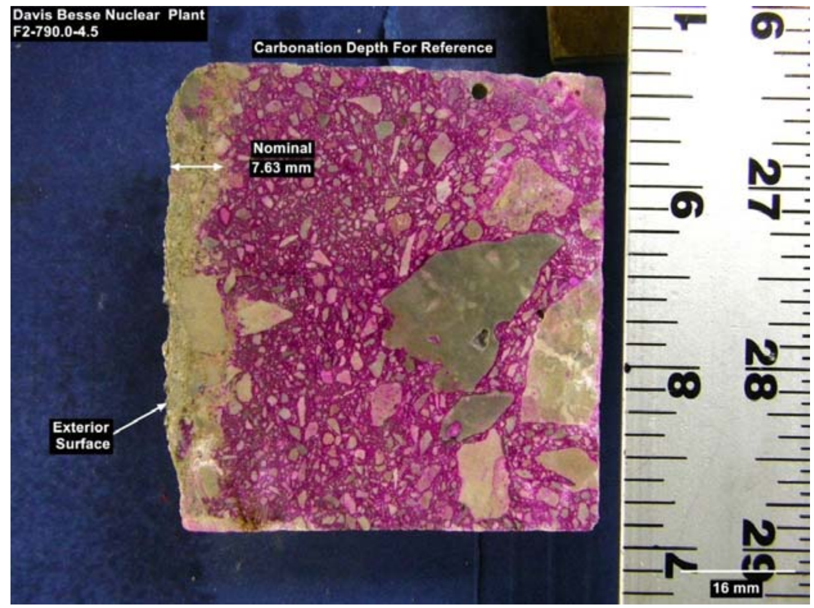
- **No evidence of micro cracks**
- **No signs of cyclic load mechanism**
- **No cyclic freeze-thaw mechanism**
- **No indication of fatigue or age related events**



Magnification at 100 Times

Shield Building Concrete Tests (cont.)

- **16 samples were tested for carbonation**
  - Average depth of carbonation is 8.57 mm (0.337 inches)
  - Maximum average 11.7 mm (0.46 inches)
  - Typical for concrete 40 years old



Shield Building Concrete - Conclusion

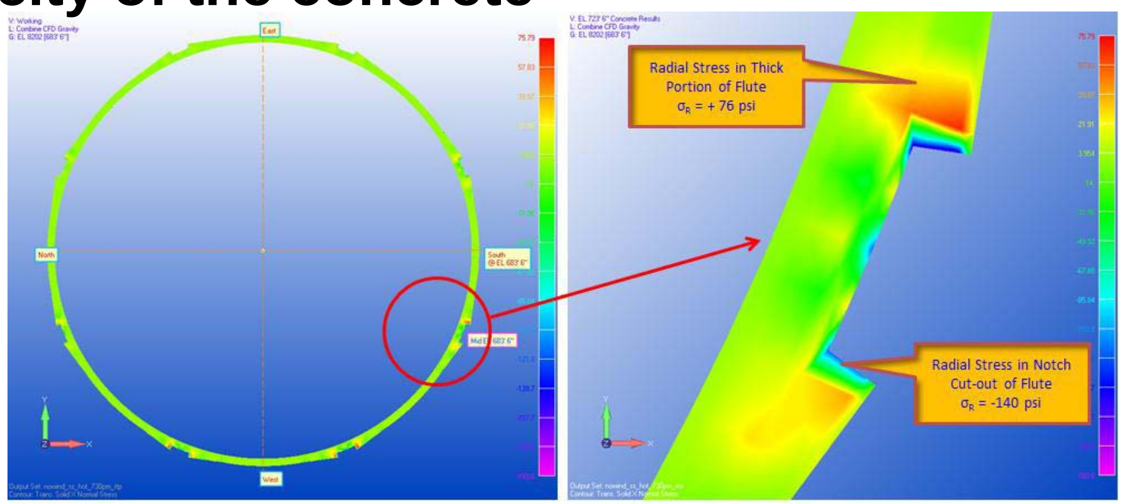
- **Crack passed through the course aggregate**
  - Strong bond between the cement paste and the coarse aggregate; therefore, initial placement concerns can be ruled out
  - Large tensile force is required to initiate the crack
- **No micro cracks identified that would indicate freeze-thaw or cyclic events**
- **Chemical properties, carbonation, corrosion, etc, were all acceptable**
- **Based on the above, concrete can be ruled out as an initiating or contributing cause**

Shield Building Configuration

- **Cracking is predominantly located in the shoulder areas, the top 20 feet of the Shield Building, and near the Main Steam Line penetration block-outs; cracking concentrated on southern exposures**
- **Shoulder areas are regions of discontinuity**
- **Limited radial reinforcing steel in the shoulder areas**
- **High rebar density (6" spacing) located at the top of the Shield Building and around the Main Steam Line penetration construction block-outs**
- **Conclusion**
  - There is a correlation between the crack locations and the physical layout of the reinforcing steel that needed to be investigated

Shield Building Analytical Analyses

- **Numerous computer analyses were performed for normal design conditions**
  - Self weight, wind loads
  - Thermal analyses (summer hot and winter cold conditions)
  - Fujita Category 2 tornado
- **Stresses were significantly below the normal tensile capacity of the concrete**



Overall View @ EL 683' 6"   Close-Up View @ EL 683' 6"

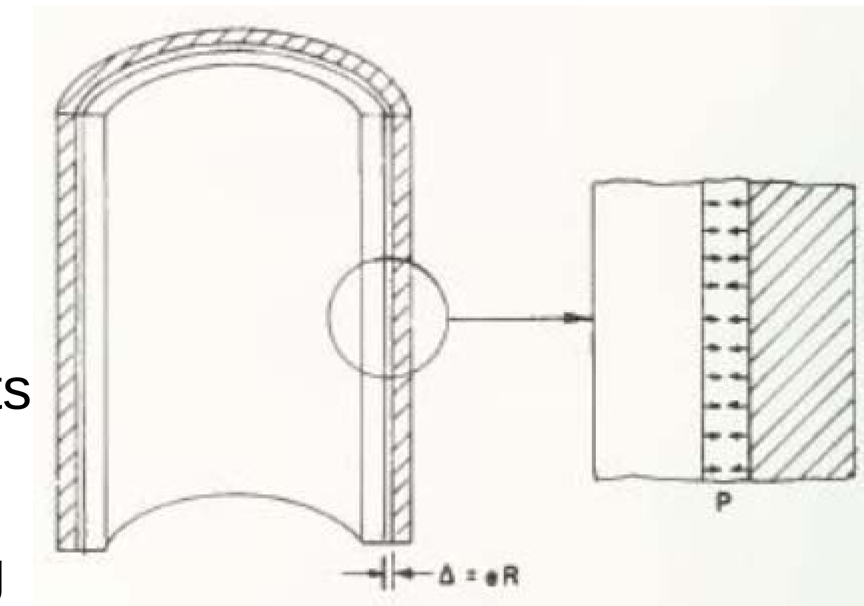
Shield Building Analytical Analyses (cont.)

- **Analysis showed:**
  - Design stresses can not initiate the laminar crack
  - Significant stresses beyond what is normally analyzed would be required to crack the concrete

- **Investigate industry experience for similar conditions**

Industry Experience with Laminar Cracks

- **Ontario Ministry of the Environment study on 50 above ground water tanks in Ontario**
- **Water migrated into the concrete from the inside**
  - Inner layer of the wall freezes and expands
  - Outer layer of wall contracts
  - Creates high radial stress
  - Results in laminar cracking



- **Conclusion: Laminar cracking as a result of water freezing is a real potential**

Shield Building Investigation into Water Intrusion/Freezing

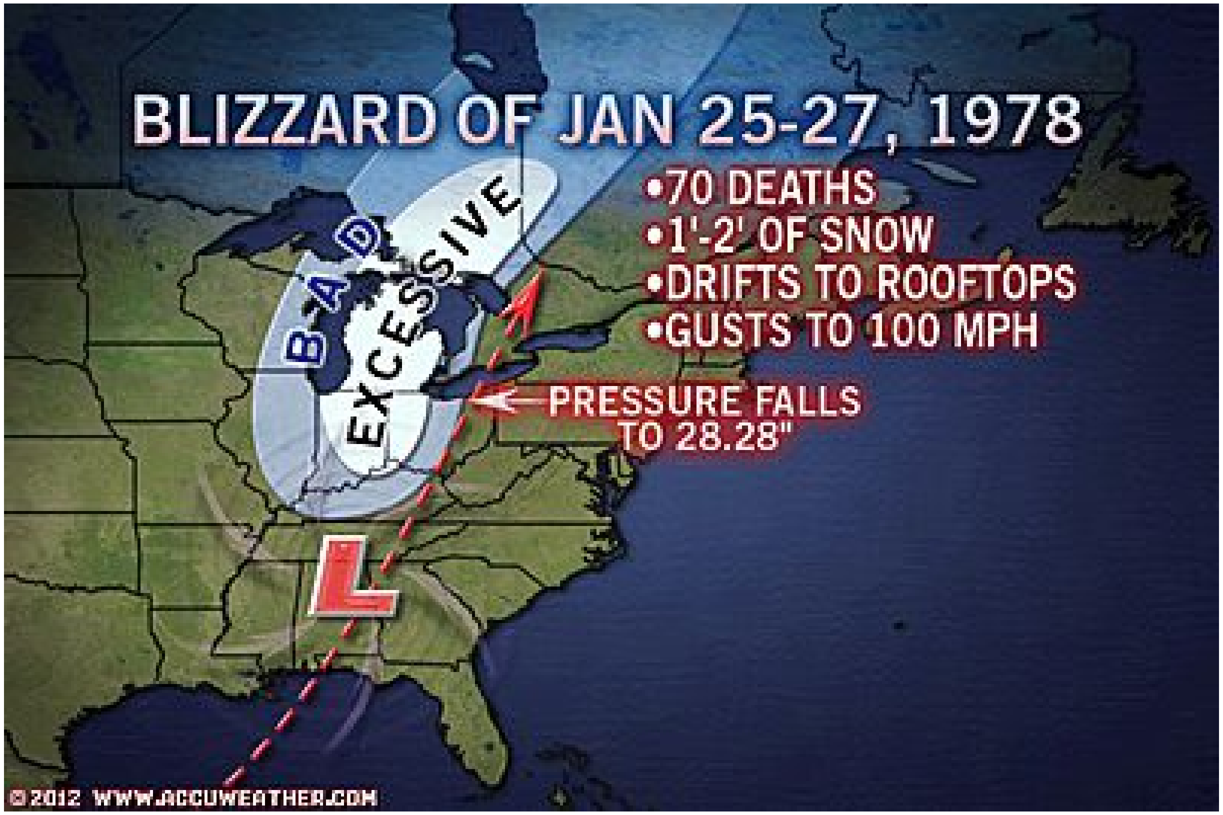
- **The effects of moisture intrusion and sub freezing temperatures was investigated as a possible cause**

- **The review of severe environmental conditions that the plant was exposed to was performed**

- **The most significant event recorded at the site and also in Ohio history was the storm of January 25-27, 1978**

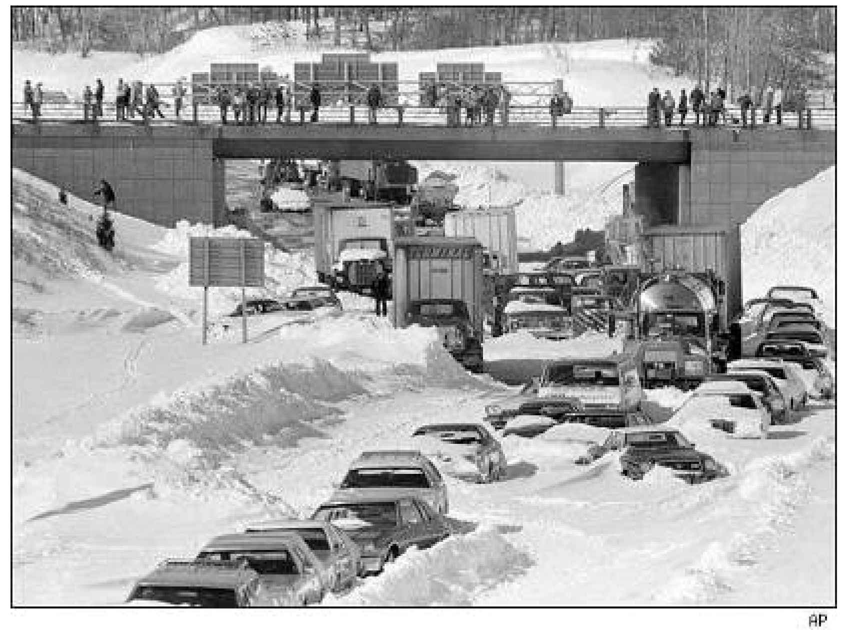
Moisture Intrusion and Low Temperatures

- **January 25-27, 1978, was the worst in terms of:**
  - Moisture
  - Winds
  - Temperature
  - Duration
  - Pressure



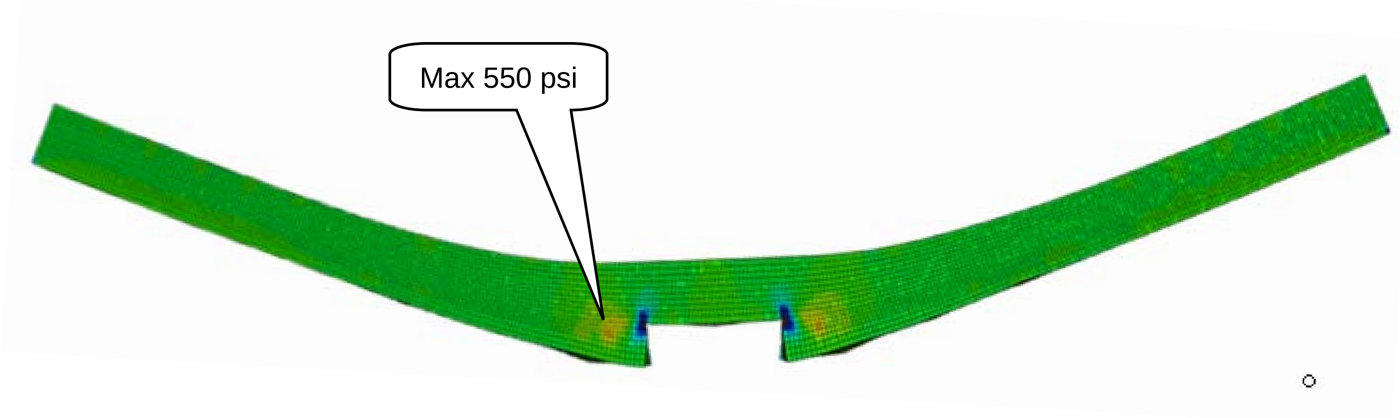
Moisture Intrusion and Low Temperatures (cont.)

- **Scenario:**
  - Temperature near zero
  - Sustained strong winds
  - Moisture penetrated the Shield Building
  - Moisture trapped in the outer layer of concrete crystallized
  - Concrete expansion exceeded the tensile capacity of the concrete and propagated the crack



Moisture Intrusion and Low Temperatures (cont.)

- **A complex computer model of the Shield Building was developed**
- **Concrete properties from the concrete core tests were used**
- **Laboratory tests showed moisture infiltration up to four inches**
- **Maximum radial stress in the shoulder area were approximately the tensile capacity of the concrete**
- **High stresses were located in areas of observed cracking**



Sensitivity Analysis – High Density of Rebar

- **A complex computer model evaluated the affects of rebar spacing to determine the potential for developing cracks**
- **Evaluation showed laminar cracks could:**
  - Form in regions of closely spaced rebar and
  - Less likely in areas were the rebar is spaced at 12 inches
- **This analysis establishes that rebar spacing is a probable contributing factor**

Summary of Analyses

- **Normal design conditions result in low stresses which could not cause cracking**
- **Moisture and freezing could cause high stresses in the shoulder areas that results in cracking**
- **Analysis shows closely spaced reinforcing steel can be a contributor to laminar cracking**
- **Observed cracking coincides with the locations of high stress in the shoulder areas and in the areas of high density of rebar; cracking concentrated on southern exposures**

Shield Building Root Cause

- **Root Cause:**
  - Lack of water sealant on the concrete exterior
- **Contributing Causes:**
  - Shoulder reinforcing details (discontinuity and no radial rebar)
  - High density of rebar spacing
  - High moisture, severe wind, and low temperature conditions

Shield Building – Preventive Action

- **Root Cause**
  - Lack of concrete sealant
- **Preventive Action to Prevent Recurrence**
  - The exposed exterior surfaces of the Shield Building will be sealed
  - Contractor has started and is expected to be completed this year

Shield Building – Additional Actions

- **The Root Cause has established several additional Corrective Actions**
  - Complete Impulse Response (IR) examinations on the Shield Building wall
  - Perform IR mapping on another structure (Auxiliary Building) to confirm assumptions of our analyses
  - Develop and implement a test program to establish capacity in an area of laminar cracks
  - Develop a Long-Term Monitoring program

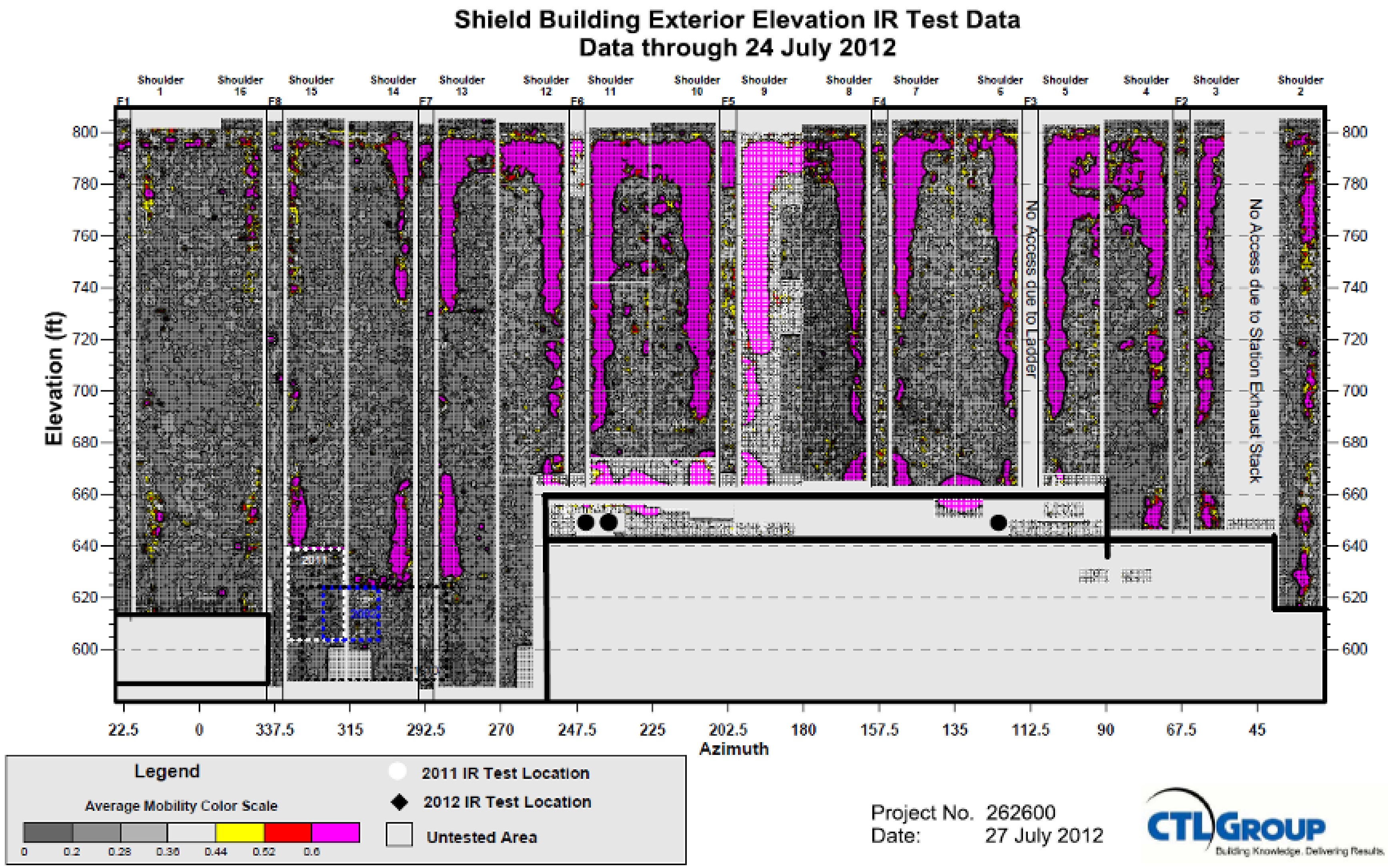
Additional Actions - IR Mapping

- **Complete IR examinations on the Shield Building wall and an independent structure**
  - All accessible areas of the Shield Building wall were mapped
  - Over 60,000 individual readings were obtained to fully characterize the condition of the building

Additional Actions - IR Mapping (cont.)

- **The IR validated our original assessment that the laminar cracks are generally confined to:**
  - The shoulder areas
  - Top of the Shield Building
  - Near one corner of the Main Steam Line penetration
  - Southern exposure
- **Impulse Response reading on an independent site structure validated that laminar cracks are not present**

Additional Actions - IR Mapping (cont.)



Additional Actions – Testing

- **Tests were developed and conducted at two nationally recognized universities**
- **Professors are industry experts and are American Concrete Institute (ACI) Committee members**

Additional Actions – Testing (cont.)

- **Two different methods were used to create laminar cracks in the samples to be tested**
- **Results were independently verified**

Additional Actions – Testing (cont.)

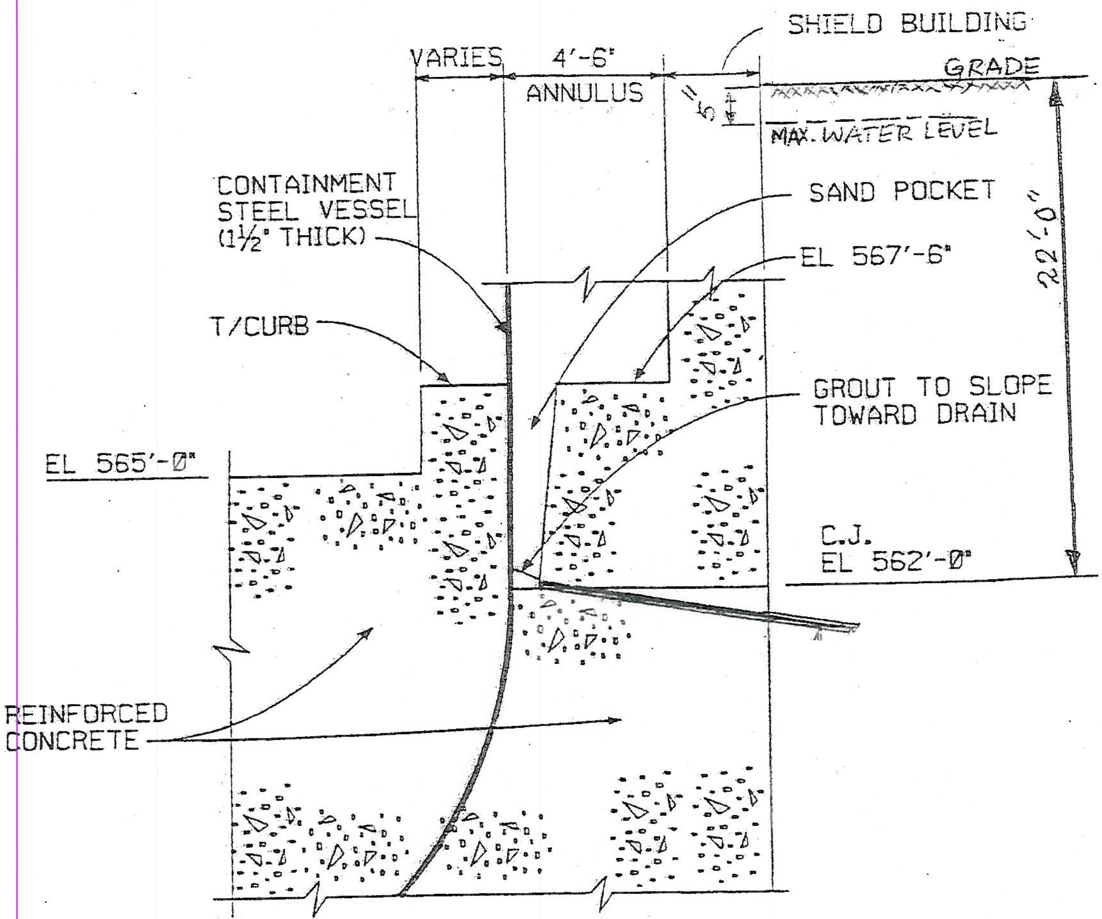
- **Testing results**
  - Full capability of reinforcement is maintained in regions with longer splice lengths (upper portion of Shield Building)
  - Results showed near to full capability of reinforcement in regions with shorter splice lengths
- **Testing conclusions**
  - The tests provide high confidence of the capability of the rebar located in regions of laminar cracking
  - Testing confirms the assumptions made in structural calculation prior to restart were very conservative

Additional Actions – Long Term Monitoring

- **Establish a Long-Term Monitoring Program**
  - FENOC has established a long-term monitoring plan that includes:
    - Monitoring existing core bores for crack propagation
    - Inspection of the integrity of the Shield Building coatings
    - Inspection of the integrity of other safety related building coatings

License Renewal Application Summary

- **Application has been reviewed to NUREG-1801, Rev. 2**
- **43 Aging Management Programs identified**
- **49 Commitments**
- **Site Program Owners and Subject Matter Experts involved in:**
  - Development of application; audit & inspection interviews; conference calls with NRC; RAI responses; and, Commitment development
- **SER Open Item responses under review by NRC staff**
- **Proposed programs address aging management at Davis-Besse for the period of extended operation**



SHIELD BUILDING
VARIES
4'-6"
ANNULUS
GRADE
5"
MAX. WATER LEVEL
CONTAINMENT
STEEL VESSEL
(1½" THICK)
SAND POCKET
EL 567'-6"
22'-0"
T/CURB
GROUT TO SLOPE
TOWARD DRAIN
EL 565'-0"
C.J.
EL 562'-0"
REINFORCED
CONCRETE

Advisory Committee on Reactor Safeguards License Renewal Subcommittee

Davis-Besse Nuclear Power Station

Safety Evaluation Report with Open Items

September 19, 2012

Brian K. Harris, Project Manager
Office of Nuclear Reactor Regulation

Introduction

- Overview
- Section 2: Scoping and Screening Review
- License Renewal Inspections
- Section 3: Aging Management Program (AMP) and Review Results
- Section 4: Time-Limited Aging Analyses (TLAAs)

Overview

- LRA Submitted by letter dated August 27, 2010
- Pressurized Water Reactor (PWR), Babcock & Wilcox nuclear steam supply system
- Operating license for NPF-3 expires April 22, 2017
- Located approximately 20 miles east of Toledo, OH

Overview cont'd

- Scoping and Screening Methodology Audit
  - Jan 24-28, 2011
- Aging Management Programs Audit
  - Feb. 14-25, 2011
- Regional License Renewal Inspections
  - April 25-29, 2011
  - May 9-13, 2011
  - Aug 22-26, 2011

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Section 2 - Structures and Components Subject to Aging Management Review

- Section 2.1 - Scoping and Screening Methodology
- Section 2.2 - Plant-Level Scoping Results
- Section 2.3 - Scoping and Screening Results Mechanical System
- Section 2.4 & 2.5 - Scoping and Screening Results Structural & Electrical

Section 2 - Structures and Components Subject to Aging Management Review

- The staff determined through a review of documents, discussions and plant walkdowns:
  - nonsafety-related pipe attached to safety-related pipe had not been included within the scope of license renewal to ensure structural integrity
  - equipment that was no longer required had been placed in an abandoned state
  - nonsafety-related domestic water valve and other nonsafety-related fluid filled SSCs, which could potentially impact safety-related SSCs through spray or leakage, had not been included within the scope of license renewal.

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71002 Inspection Summary

- 54.4 Scoping & Screening SSCs
- Reviewed 28 of 40 AMPs during April-May 2011
- Reviewed AMPs changed due to RAIs during August 2011
- Operating Experience Review

71002 Inspection Results

- Inspection results support a conclusion there is reasonable assurance that the effects of aging will be adequately managed
- Scoping of SSCs was acceptable
- Documentation supporting the application was auditable & retrievable
- Reports 05000346/2011010 & 05000346/2011012

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Section 3 – Aging Management Review

- Section 3.0 – Aging Management Programs
- Section 3.1 – Reactor Vessel & Internals
- Section 3.2 – Engineered Safety Features
- Section 3.3 – Auxiliary Systems
- Section 3.4 – Steam and Power Conversion System
- Section 3.5 – Containments, Structures and Component Supports
- Section 3.6 – Electrical and Instrumentation and Controls System

Safety Review Results

- Safety Evaluation Report with Open Items was issued July 2012
- 4 Open Items

  OI-3.0.3.2.15-1 Shield Building Cracks

  OI-B.1.4-1 Operating Experience

  OI-4.2.4-1 Pressure-Temperature Limits

  OI-4.2-1 Upper Shelf Energy

Shield Building Laminar Cracks

Open Item 3.0.3.2.15-1

- Cracks observed in multiple locations
- Cracking event driven
- Additional information required on how the applicant will age manage the laminar cracks in the concrete shield building

OI 3.0.3.2.15-1: Information Required

- Cracking
  - Justify not verifying extent of cracking with NDE techniques
  - Justify adequacy of the core bore inspection sample size, distribution, and inspection frequency
  - Describe acceptance criteria and inspector qualifications
- Coating
  - Describe inspection methods and acceptance criteria
- Scope of Proposed AMP
  - Explain how degradation will be prevented or identified in other structures

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Operating Experience for Aging Management Programs (OI B.1.4-1)

- Clarify how operating experience review will address aging to ensure continued effectiveness of AMPs or develop new AMPs
- Final License Renewal Interim Staff Guidance, LR-ISG-2011-05, "Ongoing Review of Operating Experience," issued in March 2012
  - Screening and identification of incoming operating experience items for potential aging impacts
  - Inclusion of AMP findings, GALL Report revisions, and guidance as sources of operating experience
  - Consideration of materials, environments, aging effects, aging mechanisms, and AMPs in operating experience evaluations
  - Training on aging for personnel that implement AMPs and process operating experience
  - Incorporate guidelines for reporting plant-specific operating experience on aging to the industry

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Section 4 – Time-Limited Aging Analysis

- Section 4.1 – Introduction
- Section 4.2 – Reactor Vessel Neutron Embrittlement of the Reactor Pressure Vessel and Internals
- Section 4.3 – Metal Fatigue
- Section 4.4 – Environmental Qualification of Electrical Equipment
- Section 4.5 – Concrete Containment Prestress
- Section 4.6 – Fatigue of Primary Containment, Piping, and Components
- Section 4.7 – Other Plant-Specific TLAA

Pressure-Temperature Limits

Open Item 4.2.4-1

- LRA did not adequately describe how P-T limit curves would be generated for the PEO (§54.(c)(1)(iii))
- Ferritic components of the reactor coolant pressure boundary, including discontinuities such as nozzles, must be considered as potentially limiting components for the generation of P-T curves

Upper Shelf Energy (USE)
Open Item 4.2-1

- Applicant must demonstrate a USE value of at least 50 ft-lb for all RV beltline welds at end of life or submit an equivalent margins analysis to demonstrate equivalent margins of safety against fracture.
  - The applicant did not provide an acceptable basis for using generic initial value of 70 ft-lbs in developing its USE for the Linde 80 RV beltline welds.

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Proposed License Condition
Containment Vessel Inspection

- Operating experience with borated water leakage migrating through concrete structures inside containment
- Possibility that leakage has come into contact with inaccessible portions of the steel containment vessel causing corrosion
- Staff has proposed a license condition to remove concrete and inspect a normally inaccessible portion of the vessel

Conclusion

On the basis of its review and pending satisfactory resolution of the open items, the staff will be able to determine that the requirements of 10 CFR 54.29(a) have been met for the license renewal of Davis-Besse Nuclear Power Station

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R-III Summary

Site	License Renewal Date	Extended Period
Braidwood 1 & 2		
Byron 1 & 2		
Clinton		
Davis-Besse		
Dresden 2 & 3	Oct-04	Dec-09; Jan-11
Duane Arnold	Dec-10	
D. C. Cook 1 & 2	Aug-05	
Fermi 2		
Kewaunee	Feb-11	
LaSalle 1 & 2		
Monticello	Nov-06	Sept-10
Palisades	Jan-07	Mar-11
Perry		
Point Beach 1 & 2	Dec-05	Oct-10 (U1)
Prairie Island 1 & 2	Jun-11	
Quad Cities 1 & 2	Oct-04	

Containment Elevation