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NUCLEAR REGULATORY COMMISSION

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565TH MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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THURSDAY,

SEPTEMBER 10, 2009

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ROCKVILLE, MARYLAND

The Advisory Committee met at the Nuclear Regulatory Commission, One White Flint North, Commissioner's Conference Room, 11555 Rockville Pike, at 8:30 a.m., Dr. Mario V. Bonaca, Chairman, presiding.

COMMITTEE MEMBERS:

MARIO V. BONACA, Chairman

SAID ABDEL-KHALIK, Vice Chairman

GEORGE E. APOSTOLAKIS, Member

J. SAM ARMIJO, Member-at-Large

SANJOY BANERJEE, Member

CHARLES H. BROWN, Member

MICHAEL L. CORRADINI, Member

OTTO L. MAYNARD, Member

COMMITTEE MEMBERS (Continued):

DANA A. POWERS, Member

HAROLD B. RAY, Member

MICHAEL T. RYAN, Member

WILLIAM J. SHACK, Member

JOHN D. SIEBER, Member

JOHN W. STETKAR, Member

C-O-N-T-E-N-T-S

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

8:31 a.m.

CHAIRMAN BONACA: Good morning. The meeting will now come to order.

This is the first day of the 565th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the Committee will consider the following:

License renewal application and the Final Safety Evaluation Report for the Indian Point Nuclear Generating Units 2 and 3.

License renewal application and Final Safety Evaluation Report for the Three Mile Island Nuclear Station Unit 1.

Draft Final Revision to Regulatory Guide 1.189, Fire Protection for Nuclear Power Plants.

Draft Digital Instrumentation and Control Research Plan for fiscal years 2010 to 2014.

And preparation of ACRS reports.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act.

Mr. Sam Duraiswamy is the Designated Federal Official for the initial portion of the meeting.

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

Region 1 staff and other personnel will be on the phone bridgeline to listen to the discussion regarding Indian Point, 3MI license renewal application, and Regulatory Guide 1.189.

To preclude interruption of the meeting, the phone will be placed in a listening mode during the presentations and Committee discussion.

A transcript of a portion of the meeting is being kept, and it is requested that the speakers use one of the microphones, identify themselves, and speak with sufficient clarity and volume so that they can be readily heard.

I will begin with some items of current interest.

Ms. Alesha Bellinger joined the ACRS staff as a Senior Program Analyst in July 2009. She has been with the NRC since 2003.

Prior to joining the ACRS staff, Ms. Bellinger worked in NRR as a Technical Assistance Project Manager, where she managed and provided fiscal planning for over $60 million of contractual activities.

Also, she worked in the Office of Small Business and Civil Rights as a Special Assistant to the Office Director.

In addition, she worked in the Office of Chief Financial Officer as a Budget Analyst, conducting various budget analyses and developing an NRC budget formulation process.

Ms. Bellinger holds a B.S. degree in accounting with a concentration in business relations from the University of Maryland, University College, and an Associate Degree in accounting from Montgomery College.

Currently, she is working toward becoming a Certified Public Accounting.

Ms. Bellinger will be working as a Special Assistant to the Director of PMDA regarding internal controls, quality assurance, and as a liaison officer.

Welcome aboard.

(Applause.)

Mr. Jorge Cruz-Ayala joined the ACRS staff in August 2009 as a general engineer. He holds a B.S. degree in electrical engineering from the University of Puerto Rico. In the past two summers, he worked as an intern for the aviation industry.

He will be performing tasks in the digital

I&C areas assigned.

Welcome aboard.

(Applause.)

And that wraps up the introductions.

So now we can move to the first item on our agenda today. It is the Indian Point license renewal application.

Mr. Otto Maynard will lead us through the presentations.

MEMBER MAYNARD: Thank you, Mr. Chairman.

Indian Point is a two-unit Westinghouse four-loop PWR about 24 miles north of the New York boundary line. It has had multiple ownership. Currently, it is under the same ownership, and the applicant will be talking, and basically, the application is for both units, IP2 and IP3, for a license renewal.

We had a Subcommittee meeting March the 4th to discuss the Indian Point license renewal application. At that time, we had an SER with open items. There were a number of open items. Several of those were being closed at the time of the meeting, but now we have the SER with the open items all addressed in that.

Today the applicant and the staff will be addressing several of those. We are not going to be going over every one of the items that was open at that time, but, of course, anything is fair game for any of the members to ask questions about during today's meeting.

We had the benefit of discussion with the staff and with the applicant at that Subcommittee meeting. We also had opportunity to discuss it with the public. Mr. Musegaas -- I may have mispronounced the name -- representing Riverkeeper, provided a discussion, some information, gave us an opportunity to interact with him.

We have also received, of course, a number of documents, not only the license renewal application and the SERs associated with Indian Point, but also three letters from Riverkeeper with concerns and issues that they wanted to make sure that we have considered. Those letters, dated February the 27th, April the 16th, and September the 4th, the members all have copies, and Mr. Peter Wen of the ACRS staff has put additional copies at the table here, in case anybody didn't have their copy with them today, and of course to be considered in our review and discussion of this license renewal application.

With that, rather than going into much

more detail, I think it is more important to go ahead and get into the issues, the questions, and the discussion. So I am going to turn it over to Mr. Brian Holian of the staff to introduce this morning's discussion, and then go from there.

MR. HOLIAN: Good. Good. Thank you. Thank you, ACRS and Chairman.

My name is Brian Holian, and I am the Director of the Division of License Renewal. I will just do brief introductions and turn it over to the licensee.

The agenda is set up very well this morning. ACRS staff has divided many of the items between Indian Point and the Entergy staff to discuss and the NRC staff.

As the Chairman mentioned, there were numerous items open at the draft SER period. However, a majority of those, the staff had the information in hand and, as was mentioned, we are in the process of closing.

There were no major issues really during the staff review in the preceding months here, as we closed those issues. You will hear that today.

Just to highlight a few members of NRC staff: Dr. Sam Lee, my Deputy, is over to my left.

Two of the main presenters are over to my right for the NRC staff. That's Kim Green, the Project Manager, and Glenn Meyer, Senior Reactor Inspector from the Division of Reactor Safety in Region 1.

With that, I will turn it over to Fred Dacimo, the Vice President for Entergy, and the NRC staff will follow their presentation.

MR. DACIMO: Thank you, Mr. Holian.

Good morning. My name is Fred Dacimo. I'm the Vice President for License Renewal for Entergy Corporation for Indian Point.

This morning in the audience we have a number of people from Entergy I would like to briefly introduce.

Joe Pollack, he is our Vice President for the site. Pat Conroy, who is our Director of Nuclear Safety Assurance. Don Mayer, who is Director of Emergency Planning. He will be one of the presenters this morning.

Gary Young, who is our Director of Business Development. Tom Orlando, who is our Director of Engineering. He will be one of the presenters this morning.

Bob Walpole, who is our Manager of Licensing at Indian Point. Mike Tesoriero, who is our

Manager of Programs and Components. Tom McCaffrey, who is our Manager of Design Engineering.

John Curry, who is our Project Manager of License Renewal. Mike Stroud, who is our Entergy Project Manager, License Renewal. Alan Cox, who is our Technical Manager for License Renewal.

Richard Drake, who is on my left, he is one of our presenters. He supervises Civil Structural Engineering. Nelson Azevedo, who is our Supervisor of Programs.

I want to thank the ACRS for providing us with this opportunity this morning. We look forward to answering any questions that the ACRS may have in any area.

I am going to be very brief on the background because I know it is redundant for many members of the ACRS who sat through the Subcommittee meeting.

But we are two Westinghouse units that are north of New York City. There are four loops. Unit 2 went commercial in August of 1974. Unit 3 went commercial in August of 1976. They are, as you can see from the photographs, constructed with reinforced concrete containments.

Our license renewal application

incorporated the lessons learned from all previous applications. Peer review was conducted, utilizing NEI. We also did an internal review, using our Safety Review Committee and our Quality Assurance Department, and our application was prepared using Entergy resources, both corporate and site, with all comments being resolved.

As previously mentioned, our final SER was issued on August 11th 2009. The license expires for each one of these units. Unit 2 is in September 28th of 2013, and Unit 3 is in September 12th of 2015.

With that, I would like to get right to the issues that our understanding is that the ACRS would like to discuss. We have five topics this morning, which are listed above.

With that, we will get right into the first one, which is the containment penetration cooling system. That will be conducted by Mr. Richard Drake.

MR. DRAKE: Good morning.

At the last ACRS presentation, a question was asked when we were discussing the hot penetration cooling system, if our analysis had looked at a no-flow condition where there was blockage for any reason. Was there any conduction heat transfer from the concrete? So the question was, whether we had any plugging from any source, what would be the ultimate effect on the temperature, and would we exceed our 200 degrees Fahrenheit? Our normal operating condition is well below 200 degrees Fahrenheit.

Calculations were performed, and they did assume a no-flow condition, which would indicate that the temperature would exceed 200 degrees. The calculation would show that, using conduction heating, the temperature would reach 300 degrees in approximately 58 days of time to take corrective actions.

The design of the system is very simplistic. The operating practices assure the high system reliability.

Operators perform daily rounds. There's also annunciators in the control room which would identify if any blower is out of service.

Operating procedures provide corrective actions, based on pressure instrument readings, and the procedures also give guidance on cleaning out the penetrations, replacing filters, replacing silencers, or putting the back-up blowers into service.

Plant operating experience indicates that the system is properly managed and is reliable. We went back for the past 12 years and found 13 events which indicated that corrective actions were taken when there were issues. Most of them dealt with replacing belts on blowers. Also, as we said, the concrete properties would not degrade at temperatures below 300 degrees.

MEMBER ARMIJO: Just a quick question: in your operating experience, did you ever find any situations where the channels were plugged or fouled?

MR. DRAKE: They had five indications where there was potential blocking in the system, and that was cleaned out.

MEMBER STETKAR: You mentioned daily operator rounds as a means of detecting this problem. How exactly would the operators detect plugging of the channels? Everything that you mentioned seemed to indicate that they checked operability of the fans and the filters and things like that that are operating things.

MR. DRAKE: They also do monitoring of the vibration of the blower. So, if you had blockage, you would also see higher vibrations in the blowers also. There's a pressure gauge, also, that would show the pressure.

MEMBER STETKAR: Is that pressure DP

across the channels or is it DP across the filter on the blower?

MR. DRAKE: I believe it is on the channel, the inlet.

MEMBER STETKAR: Thank you.

MEMBER CORRADINI: Can I just follow up, since I'm not familiar with the system and I don't remember being at the Subcommittee meeting, is the honest answer?

So is it part of the procedure of the operator, when they do their daily rounds, to look at these pressures and temperatures? In other words, are they given instruction or at least trained so they know what to look for to look for plugging or looking for unoperability or degraded operability of the system?

MR. DRAKE: Yes.

MEMBER BANERJEE: Were the plugs detected from the DP signals? How were they detected? The five cases you said.

MR. DRAKE: I don't remember exactly what the indication, but they did detect, five indications where they detected some type of blockage. One was identified as vibration.

MEMBER BANERJEE: And then they blew these plugs out?

MR. DRAKE: Yes.

MEMBER BANERJEE: What was the plug? Did they get any indication of that?

MR. DRAKE: One was a potential bird's nest that was on the outlet.

MEMBER BANERJEE: Thanks.

MR. ORLANDO: We have a redundant system. So system that is not service, sometimes --

MEMBER MAYNARD: You need to use the microphone.

MR. ORLANDO: The system has redundancy. So the system that is not in service, we had a bird that built a nest in it. So, when we placed it in service, there was initial blockage. We had to clean that out.

MEMBER MAYNARD: Did you say there's some periodic inspection or surveillance, some way to check the channels, or do you just rely on finding a flow blockage? Is there some periodic inspection to see that the channels are clear?

MR. ORLANDO: They do vibration, periodically checks, but it is just the operator rounds.

On a daily basis, the operators check

temperatures and pressures to detect any changes in the system. On a daily basis, the operators do rounds, and they record temperatures and pressures. If they see any deviation or abnormal readings, then they would raise it up for the corrective action program, write a work order, and then we go and clean it.

In addition, we have predictive maintenance where we go out and we do monitoring on the vibration of the blowers. If the blower vibration increases, it would be an indication that the system is not behaving correctly and it is a potential blockage.

We have had to change some belts out. It is a relatively simple system that the operations people on a daily basis review, and they look for any kind of deviations from normal.

MEMBER BANERJEE: You said that it takes about 56 hours to --

MR. ORLANDO: Fifty-eight days.

MEMBER BANERJEE: Oh, 58 days. Okay. So that is a long time. Okay. Thanks.

MEMBER POWERS: What happens to the strength of the concrete as it warms up?

MR. DRAKE: The strength of the concrete

would not be degraded up to 300 degrees. Typical temperature has been always well below 200 degrees.

MEMBER POWERS: Doesn't, in fact, the concrete become stronger as it warms up?

MR. DRAKE: Well, the concern would be over a long period of time that you would have concrete that would dry out and then start to lose its characteristics. But it would take a long extended period of time at elevated temperatures higher than 300 degrees for that to happen, and we have never experienced that.

VICE CHAIRMAN ABDEL-KHALIK: Could you tell us some more about this conduction calculation that the temperature reaches 300 degrees in 58 days? Particularly, what item has a time-constant of 58 days or in excess of 50 days in a conduction process?

MR. DRAKE: Basically, it was conduction perpendicular and parallel to the penetration into the concrete. We didn't take any movement of the air in the blower, and the highest temperature would be at the sleeve-to-concrete interface. So it would be the concrete, conducting through into the concrete, and then the air exchange onto the concrete would be the loss of the heat.

VICE CHAIRMAN ABDEL-KHALIK: But this is a conduction process. Okay? So what sets the time-constant for this process? I'm just amazed at the time; it takes 58 days.

MR. DRAKE: Well, the temperature of the pipe, and then there is a big difference in the air temperature of the concrete, and it would just take a long time for the surface. I don't have the detailed calculation in front of me. I'm sorry.

MR. ORLANDO: There is a pipe inside a pipe, and then there's air between the pipe and the penetration. So you would have the conduction of the pipe that has the hot flow air, would heat up the air, and then that air would have to heat up to a certain temperature and then conduct to the penetration itself. Then the penetration would have to heat up the surrounding concrete. That is the way we did the calculation.

MR. DRAKE: You have very thick concrete walls, and you do have some air temperatures much cooler.

MEMBER BANERJEE: So when you say 300 Fahrenheit in 58 days, do you mean that's the hottest spot?

MR. DRAKE: That would the be the hottest spot, and that would be at the sleeve-to-concrete interface.

VICE CHAIRMAN ABDEL-KHALIK: Again, in this sort of multi-layer system, what is the thickest layer that has the lowest conductivity?

MR. DRAKE: I don't have that. I don't have the calc in front of me.

MEMBER MAYNARD: Could you perhaps get back, get somebody to get back to us with that?

MR. DRAKE: Absolutely.

MEMBER MAYNARD: Okay. Go ahead and move to the next item.

MR. DRAKE: Yes.

Okay, at the last presentation, we had a presentation of our concrete containment, and we presented information, and we had more questions about the concrete conditions. So, basically, the IPEC concrete containments are monitored by the ISI IWL program.

Next slide.

We have isolated areas on the surface of the containment walls, on the outside, of degradation that exists due to Cadweld rebar joints, scaffolding attachment points, and rebar ties that were there from original construction. These were documented in our initial baseline inspections in 1995. The areas have been monitored since then and have shown no degradation, and they have no structural impact on the containment concrete.

There are 41 of these locations at IP2 and there are seven locations at IP3. All these are located on the cylinder portion, the vertical portion of the containment, and not on the dome.

These locations are currently being coated. Yesterday, actually, we applied the primer on the Unit 3 containments at these locations. We were able to, using some cranes, get up close and direct measure them, and clean. They were confirmed that it was just surface rust, light surface rust; cleaned and applied the coating. Then we will be moving on to Unit 3 -- Unit 2. Sorry.

Any questions?

(No response.)

Okay. During the last presentation, also, the Committee asked for the presentation of the ILRT data. So Tom Orlando is here to present that.

MR. ORLANDO: Okay. The past ILRT results were all below the required .075 percent of free volume per day, and there were no unexplained changes in ILRT leak rates.

The next slide shows the graphical tabular results of past integrated leak rate tests at the station, and they were all below the .075 percent.

So, in conclusion, all the tests have been satisfactory, and we also do visual inspections of the containment structures. They have also been performed at satisfactory levels.

Any questions?

(No response.)

Okay. I will reintroduce Rich then.

MR. DRAKE: Okay. For the last presentation to the ACRS --

MEMBER BROWN: Yes, I did have a question. When you look at your graph -- maybe I ought to put my glasses on first -- it appears that the 2006 data for both plants is higher than all the preceding data, and not by an insignificant amount. It is almost -- I'm just trying to do the eyeball check -- like .62 versus .55, which is about 10 percent change for IP2, and for IP3 about 15 percent, it looks like, something.

MR. ORLANDO: Yes, and I can explain it.

MEMBER BROWN: Well, you made the statement, and there is no integrity question here. It is just looking at this; it is all below the .075, but, in fact, if I looked at this chart, I would say, well, yes, I am seeing some effects of time, and it is higher.

Now I don't know -- go ahead. I'm sorry. I will let you answer.

MR. ORLANDO: That's okay. When I said no unexplained changes, the difference between the earlier test results, which I would say are from the 1992 time period and earlier, they were 24-hour test methodologies.

In the 2005-2006 timeframe, we had an industrywide option that allowed us to use a shorter duration test, and that is an eight-hour test versus a 24-hour test. It is a more conservative test methodology. It includes more uncertainties, and the test results did include the addition of those higher uncertainties.

So we attributed that to a test methodology issue. It is a shorter-duration test. If we had let the test go out to the 24 hours, it would have been more in line with the other test results.

I would say, having managed both of those tests, the containment itself was fine. So we didn't feel that was unexplainable.

MEMBER BROWN: Why is eight hours more conservative than 24 on a physics basis?

MR. ORLANDO: It is a statistical approach. The more data points you have, the more confidence you have in the readings. So, if you do a 24-hour test, you have more confidence in the reading and you have less uncertainty. So, on the shorter-duration tests, you project out at the eight-hour point what it would be at the end of 24 hours.

MEMBER MAYNARD: I don't think you are saying that the eight-hour test is more conservative. You have to toss more conservatism in if you take credit for the eight-hour test.

MR. ORLANDO: That is correct.

MEMBER BROWN: I got that. Thank you.

CHAIRMAN BONACA: Just a reminder, we have people on the line listening in. They are having trouble. So make sure that you speak close to the microphone and loud, and also leave your microphones on.

Okay.

MEMBER MAYNARD: All right. We are ready to go to the next item?

MR. DRAKE: Yes. Okay. At the last presentation, we were talking about the November 1973 event at Unit 2, and the ACRS had some questions. We had talked about the liner deformation. It will be addressed in questions about the concrete conditions.

So, basically, in November 1973, the plant tripped from 7 percent power, and a water hammer event occurred. We had a crack in a pipe, and we had some flashing steam that impinged on the unprotected containment liner. It was uninflated at that time and caused the liner some deformation.

This consisted of a bulge, approximately a bulge of 5/8th inches, about 2-feet high or wide, running horizontally about 60 feet all along the perimeter of the containment. This was an intermittent bulging effect.

Next slide.

Evaluation of the steam water throttled exit from the pipe concluded that the temperature on the liner and the concrete was below 300 degrees. As we have stated previously, below 300 degrees, you wouldn't expect any damage, especially for the shorter duration that this occurred for.

IRLTs and magnetic particle inspections of the liner were performed at the time and proved that there was no damage to or cracks in the liner.

Weld channel testing has been performed at the time and continuously since then. The weld channel consists of structural channels that are welded with seal welds over the existing containment liner plate welds, and that is constantly monitored with pressure to show that there's no weld leakage. That has shown that there is no loss or degradation of containment integrity.

Next slide.

Ultrasonic inspections showed that nine of the 28 L-shaped studs in the bulge area were broken. The question was, what was the damage to the concrete behind the liner? We did some calculations, and we showed that, by design, the half-inch diameter studs are the controlling point of the design of the stud, and that the stud would break itself well before the containment concrete damage would occur.

Insulation was installed over a larger section of Unit 2 containment, including extending up over the liner, which included the bulged area, so that this event would not occur again. That, also, was then incorporated into the design of Unit 3.

The inspection of the bulged liner behind the insulation will be performed before the period of extended operation.

MEMBER STETKAR: How will that inspection be performed?

MR. DRAKE: We are going to remove the

insulation, and we will do a visual inspection of the liner, in accordance with the IWE program.

So, in conclusion, the 1973 feedwater line event did not adversely affect the containment liner or concrete conditions.

MEMBER MAYNARD: Now, as I recall, you did a visual inspection of it not too long ago, and you made the statement that it was in the same condition as it was left in after the repairs were made.

MR. DRAKE: That is correct. We performed an inspection during the 2008 outage with the insulation on, and we confirmed that the liner condition is in the same condition that it was in and deformation pattern that it was originally. So there have been no change to the condition.

MEMBER MAYNARD: Okay, the next item.

MR. DRAKE: Okay. At the last presentation, we made a presentation on the IP2 refueling cavity leakage. We made a presentation, and there was a question about the safety significance of the leak and, also, you requested some better figures to show the flow paths. So we have brought those figures today. We will show them to you.

Refueling cavity leakage has no safety significance. This is based on the design margin in this area, of the structure itself. We have also previously stated that the industry data has shown that the leakage through this type of liner into the concrete surface would not degrade the reinforcing steel or the concrete.

The leakage occurs during approximately a two-week period while the canal is filled during refueling outages, and the refueling outages occur every two years.

Industry experience: we have previously quoted our own IP3 and IP2 experience on this. Recently, EPRI came out with a new study which supports a conclusion that degradation of the reinforcing steel and concrete is negligible.

The leak location, the refueling cavity begins to leak when the cavity has been filled to the 80-foot to 85-foot elevation, which is approximately midway up the cavity liner. It is a mid-weld. I will show that to you shortly.

The leakage occurs from three primary areas, and the leakage is collected in the sump and pumped through a liquid radwaste processing.

Next slide.

We have evaluated on several occasions, with the conclusion that the leakage had negligible impact on structural integrity of the refueling cavity walls and adjoining structure. This was supported in 1993, where we actually removed a section of the liner and took core samples and tested them, and showed that there was little permutation into the concrete and little degradation to the reinforcing steel.

MEMBER SIEBER: Have you taken any steps to stop the leaks?

MR. DRAKE: Yes, we have.

MEMBER SIEBER: What are the?

MR. DRAKE: We have applied a ceramalloy coating to many areas of the liner in weld areas which we thought were leaking and plug welds at the midpoint of the plates. We have had limited success.

We also applied an Instacoat coating, a strippable coating, every outage. So we apply the coating, and then at the end of the outage, since it is not DBA-qualified, we remove that coating. The ceramalloy is qualified.

MEMBER SIEBER: Has any of that been effective?

MR. DRAKE: It has been partially effective. It has helped reduce it, but it hasn't eliminated it.

It has been very troublesome tracking down everything. We believe we see three new areas or some areas where the ceramalloy has been removed or partially removed. We are moving forward for a new process to try to take this, but we have not been successful to date.

MEMBER SIEBER: Are you going to address this point?

MR. DRAKE: Yes.

MR. DACIMO: We are going to address your point in a minute here in our presentation.

MR. DRAKE: Yes.

Next slide.

The future plans: what we plan to do is we are going to do more inspections prior to the extended period of operation. So, right now, in the upcoming outage planned for 2010, we plan to remove the liner in two sections and also take core bores from a third location, and open up the concrete and to expose the reinforcing steel and do visual inspections of the reinforcing steel. That we have made as a license renewal commitment.

As we have stated, we have potential cavity liner repair activities planned, which include the interim Instacoat coating. But we are also looking at an industry process where you have a silicone-type sealant with stainless backing plates, and we want in phases to apply this to the three worst areas at first and see how successful that is to try to stop it.

And if a solution is not determined and we cannot stop the leakage, we have committed to take additional core samples, reinforcing steel, within the first 10 years of the period of extended operation.

MEMBER RYAN: How much liquid do you generate in the collection once you have filled beyond 85 per cycle?

MR. DRAKE: We get four gallons to seven gallons per minute leakage from the cavity.

MEMBER RYAN: What is seven gallons a minute?

MR. DRAKE: That is for a two-week period.

MEMBER ARMIJO: Is that after the ceramalloy remediation though?

MR. DRAKE: Yes. That was some of these current ones. The ceramalloy we have applied in certain locations which we thought were the worst cases, and we still have some leakage. So we still see these three areas as a potential where we want to go after next.

So we still have the ceramalloy in place.

The difficulty going forward is now we have to take that ceramalloy off, which is a process in itself, and we are still trying to get the exact locations down.

MEMBER SHACK: When do you do the rebar inspections and you remove the liner, how do you repair that?

MR. DRAKE: Then we are going to weld the liner back in place. We will put in a new piece of liner over it, weld it, and seal weld it.

MEMBER SHACK: But you haven't done that on a larger scale to block the leakage?

MR. DRAKE: No. That would be a very dose-intensive process.

MEMBER MAYNARD: I just want to confirm something here. You made the statement no safety significance to it. No. 1, I take it part of that is because it does not, this leakage does not penetrate or violate the containment integrity from a pressure boundary.

MR. DRAKE: That is correct.

MEMBER MAYNARD: And the inspections that you have done and the analyses show, it's your position that those analyses show that there has been no structural degradation to the support concrete and for the equipment it is supporting?

MR. DRAKE: That is correct.

Moving to the next slide, which shows -- I could do it with a pointer, but I will use the mouse here. Is that okay?

So, on the mouse here, you will see there's going to be three locations. We call them Charlie, Bravo, and Alpha. This location here is at the mid-height. This picture, the blue here shows the liner plates. You can see the welds. The concrete is not shown here, for clarity here. So this is the liner plate. And this is the midpoint where up on the weld we are saying is the prime suspects.

The yellow portion is graphically demonstrating or showing where the leakage comes out from the elevation below. So the leakage occurs, drips down along the inside of the liner, on the inside of the plate. When it gets to a discontinuity in the concrete, it will then come out through cracks in construction joints.

So our current plan is to, below these points here, take some samples at the low point, any we are collecting, and we are going to do this after the refueling operation. So we will see if there is any water there.

We are going to open it up, take a sample, do visual inspections, and we are going to do it here and on the far side. This is a location at the bottom, and we are going to come up from the bottom at the exit point and take a sample.

Next slide.

MEMBER RAY: Perhaps this slide is just as well for the question I want to ask. The real question is, are you confident, and if so, how, that you are capturing all the water that leaks through the liner --

MR. DRAKE: Yes.

MEMBER RAY: -- and there's not any residual amount that is entrained somewhere in the structure that you haven't --

MR. DRAKE: We have seen that when we fill up to and below this point, it stops fairly readily. So we have seen that, when you fill up, there is almost immediate correlation past this point, that it starts and stops almost instantaneously. So it flows fairly freely, and we don't believe there's any blockage.

But, with our current plans, we are going to do the inspection at the bottom of the liner plates. So, if there is any water captured, we would definitely see it, because we are going to do it after refueling.

MEMBER RAY: My question really went to whether water could be going someplace that you don't see it.

MR. DRAKE: No, because it comes down and it drips on the outside of the thick reactor pedestal here. This is all inside our crane wall. So it is all captured inside the crane wall. It goes to the trenches, and then it is fed into the sump. So it is all captured.

There is no water that goes outside the crane wall, and there is nothing that could get to the outside of the containment liner. It is all captured into the sumps.

MR. DACIMO: There is also very good correlation to the makeup water to the pools versus what you capture from the leakage.

MEMBER RYAN: What is the radiological condition of the water?

MR. DRAKE: We haven't taken a sample yet, and that is another plan, what we are going to do. We are going to monitor the water.

MR. MAYER: What's the question, Mike? I'm sorry.

MEMBER RYAN: How much radioactive

material is in the water?

MR. MAYER: The radioactive materials are, as you would expect, during a refueling evolution. So your two most significant contaminants would be tritium and cobalt-58, which, as you may recall, is the highest abundance due to the oxidation as we open up the plant.

There are, of course, the --

MEMBER RYAN: Have you had concentrations above --

MR. MAYER: Excuse me?

MEMBER RYAN: Give me an idea on concentration terms.

MR. MAYER: Boy, concentration of cobalt-58 is in the low minus 3's -- excuse me -- high minus 3's up to low 10 to the minus 2 microcuries per cc.

MEMBER RYAN: Sorry. It was 10 to the minus 3 up to what?

MR. MAYER: We can get up to 10 to the minus 2 microcuries per cc, and then, through the clean-up process -- you know, actually, I'm thinking in the loops.

The concentration in the water, actually, would be less than 70 to the minus 3 microcuries per cc. Okay, I know that because we have some other limiting parameters.

MEMBER MAYNARD: Would you identify yourself, please?

MR. MAYER: I'm sorry. I'm Don Mayer, and I'm Director of Special Projects at Indian Point.

MEMBER RYAN: Thanks.

MR. DRAKE: Okay, next slide.

Okay. That completes our presentation.

At our last presentation to the ACRS, we started discussing about the monitoring wells that are onsite and the Unit 2 spent fuel pool leak and plume. Don Mayer, who was just speaking, will come forward to speak.

MR. MAYER: Okay, good morning.

In response to the Subcommittee's -- let me just get myself situated here -- in response to the Subcommittee's request, we assembled a short presentation that provides two- and three-dimensional views of the plume, as well as a cross-sectional view that will aid in discussing a local tritium-retention mechanism that we discussed in March. That still presents a residual source of tritium near the Unit 2 pool.

We were asked to talk a little bit more

about the behavior of the plume and some of the plume plots, et cetera. So we will discuss that.

Okay, when we discussed this topic with the Subcommittee in March of this year, we talked about the elevated levels of tritium that were found in the groundwater after we identified tritium contamination during excavation near the Unit 2 spent fuel pool wall. This excavation was to install a new crane as part of our dry cask work that was going on.

When those elevated levels of tritium were detected, we began a very extensive hydrogeological study that was conducted from the fall of 2005 through the end of 2007. We are now in a long-term monitoring phase.

The first four bullets are here to just point out some of the key attributes of our site groundwater monitoring network. I will touch on some of these points further as I go through the rest of the presentation.

I would like to focus a little bit on the fourth bullet. This last bullet refers to really what is a cornerstone program going forward that has been fully proceduralized and linked to our 10 CFR 50 Appendix I effluent program as well as our offsite dose calculation manual process.

This long-term monitoring program has defined sample frequencies, investigation levels, and it is designed to accomplish the bullets that are indicated there for assessing plume attenuation over the course of time, providing data for radiological dose impact assessments, and then, of course, ongoing capability for detecting any new leaks, should they occur.

You know, we just make a point here that, throughout the investigation and in the existing long-term monitoring process, we have not identified contaminants offsite, in any of the offsite monitored locations that we have.

MEMBER BANERJEE: Can I just ask you a couple of questions about this?

MR. MAYER: Yes, sir.

MEMBER BANERJEE: The model is validated against measurements that you have been making in the past?

MR. MAYER: Yes.

MEMBER BANERJEE: Or has it been tuned against those?

MR. MAYER: Re-ask your question for me.

MEMBER BANERJEE: Did you have a model which you validated and had some predictive capability or did you have a model that you tuned against your measurements?

MR. MAYER: We developed a model with which we now have predictive capability. When this investigation started, there was only a general model of flow across the site. During the course of this investigation, we installed, as you can see here, many wells, most of which were multi-level wells.

Those wells were bored. Geophysical testing was done to identify the most fractured zones. Then, multi-level well points were established.

We then developed a conceptual model. That model actually was reviewed by NRC and USGS and state hydrologists, in concert, of course, with our development of it.

Then, as I will talk about through the presentation, we validated portions of the model with dye testing and extensive transducer measurements. We have a very robust model.

MEMBER BANERJEE: So when did you start the monitoring? How much data do you have in the monitoring program?

MR. MAYER: We have data that goes all the way back to the fall of 2005. Okay? I would say that the past seven quarters has been the most robust data because during the early part, the late part of 2005 and a good portion of 2006, we were installing wells. So that was an early set of data.

So we've got probably seven quarters' worth of data, which is reasonable, but we recognize -- and that is why we have a long-term monitoring program -- it will take some additional number of years to add confirmatory data to the model, but that is not unexpected.

MEMBER BANERJEE: So, over this period, did you find changes in time in the measurements? Or were they sort of essentially a quasi-steady-state?

MR. MAYER: No, we did find changes in time. The reason for that -- I think you are referring to changes in the trend of the concentrations, et cetera. If that's what you are referring to, the answer is, yes, we have.

We attribute that to two things. One was, when we excavated, we identified that there was some seepage from a crack in the concrete wall that was contributing some level of tritium to the groundwater table. That crack has since been covered by a metal box, and any leakage from that crack was collected in our PAB and was removed from the potential leakage path.

Also -- and I will have more to say about this as we go through the presentation, but I will bring it up now -- in 2007, we did very, very extensive inspections of the transfer canal, in particular. We did identify a pinhole leak. We believe that that pinhole leak was there from the construction and was contributing tritium on an ongoing basis.

We stopped that leak in November, actually, in July, because we drained the transfer canal to accomplish it, and then we repaired it in November. Since that time, we have seen a downward trend.

If you will allow me, I will go through the presentation and discuss that further.

MEMBER BANERJEE: Okay. We want to come back to really understand how good your model is.

MR. MAYER: Okay.

MEMBER RYAN: I think it would be helpful to follow with Dr. Banerjee's question, if you could distinguish between the hydrogeologic model, which is really the groundwater itself independent of any contaminant --

MR. MAYER: Right.

MEMBER RYAN: -- and then how you

evaluated the hydrology versus evaluated the tritium contamination in the water.

Now tritium, of course, because it seeks water uniformly, and without too much trouble, it is uniformly distributed in water very quickly as a good surrogate. But Dr. Banerjee's question, if I may, Sanjoy -- and tell me if I'm wrong -- it is really, what is the fundamental geohydrology understanding versus the contaminant flow understanding, and do they align and do they not align? How do you interpret those various datasets independently and collectively?

MEMBER BANERJEE: Yes, my concerns always are that these things are elaborate co-fits to existing --

MR. MAYER: I am sorry, I didn't hear that term. I didn't hear what you said.

MEMBER RYAN: He is worried about we're using the data just to fit a curve --

MR. MAYER: Right.

MEMBER RYAN: -- rather than describe the physical realities.

MR. MAYER: No, no, no. If you will permit me to go --

MEMBER BANERJEE: I know you solved a few partial differential equations to do that --

MEMBER MAYNARD: Why don't we let him go through the presentation and then maybe come back to some of this?

MR. MAYER: Yes, I am prepared to answer those questions. I mean I think you guys would recognize that we could have a treatise on this for a couple of days, but I do have some data that I can provide you on that.

Let me go to the next slide.

This will help to start give some perspective to answer your question. This is an aerial depiction of the Unit 2 plume and the site well field.

The blue dots that you see across here, okay, these represent all the wells that we have placed along our site. We do have wells along the southern boundary of the site.

This network of wells provides the assessment, the detection capability across the site. Now we have hired -- in fact, we have a consulting hydrology firm called GZA, which is their specialty area. In fact, they have a specialty in bedrock site investigations, which is what this site is.

The majority of the wells that you see there -- and this goes to your question, sir -- are multi-level wells. Those multi-level wells were installed first with geophysical testing to look at resistivity, to look at fracture mechanics in terms of what kind of flow rates they have in various fracture zones, et cetera, et cetera.

Then what they do is we install multiple, they call them, packers to separate the different levels of the wells. Then those wells have transducers associated with them.

So what they have done is they create a conceptual model. That conceptual model, then, is used to predict what the tritium concentrations expected to be are, and also, they would predict general flows and mass concentrations.

You will see, as we go forward, that we did some dye testing that synced up very well to the model. Now, ultimately, in the end, one of the key aspects of the model is flow input to the river and the concentration. The combination of those two things, of course, will result in the dose calculation.

So let me just continue. One of the features that you will notice here, and this was something that was initially predicted by the model. Okay? There was a consideration that there would likely be a potential for a conductivity between Units 1 and 2.

You can see, Unit 2, this is the containment building; that is the fuel pool. That is Unit 1. That is Unit No. 3.

That hydraulic conductivity did exist, and I will talk about that further with the fluorescein dye testing that we did.

This was an important factor in our ultimate remediation decisions because that conductivity there influences whether or not we would consider certain pumping strategies or attenuation or other factors.

MEMBER RYAN: Just a quick question.

MR. MAYER: I'm sorry, go ahead.

MEMBER RYAN: Do the colors relate to various concentration levels?

MR. MAYER: Yes, yes.

MEMBER RYAN: So where is it next to the Unit 1?

MR. MAYER: This is the Unit 2 pool right there. This is the Unit 1 pool right there.

MEMBER RYAN: What is the concentration level of the outer band?

MR. MAYER: The outer band, I don't have

the outer band concentration. My recollection is it is around, I would have to verify this, but I think it is in a range of like 50 to 100 thousand on the outer band.

As you get down towards the river, it is -- picocuries per liter, I'm sorry. Nearest to the fuel pool, the highest concentration that we had seen was approximately 600,000 at the early part of the investigation.

Now, as I indicated earlier, we did find and repair a pinhole leak in 2007, which I indicated was determined to be a construction defect. So that was a feeder that had been going on.

We have no evidence of an active leak at this time. I will make an important caveat to that statement.

We estimate a detection sensitivity of about .025 gallons per minute. As with any radio-chemical-type analysis, we can't preclude the existence of a leak at or below the detection sensitivity, but the current trend data supports our conclusion. Of course, the long-term program will continue to monitor that.

There is a documented retention mechanism or compartment that I will talk about a little more in the next slide, which continues to feed the plume and, hence, the reason why we continue to see tritium downstream, and will for some long period of time.

Oh, yes, I forgot. I'm sorry. I had it on my slide here.

I talked a little bit about the conductivity here. As you may recall, some of you, from the March presentation, we had a leak at the Unit 1 plant. That pool has all been removed. Those pools have all been drained in 2008, and we are in a long-term monitoring program there. The focus here, of course, is on Unit 2, which was the request.

Also, another important point to make -- and I will talk again when we get into the dye testing -- but, right there, there's three wells. Okay? Those three wells are very near the Unit 2 spent fuel pool, and they represent a very sensitive sentinel well location for early detection.

We base our conclusions on the leakage condition on about seven quarters' worth of monitoring data. There's two parameters of interest that we look at.

No. 1, the individual well concentrations themselves are trending down. Okay? We expect, and we have started to see, kind of an asymptote as we reach the next level of steady-state, where now we've got the pinhole solved, but we still have the input from the other compartment.

Then, as well as the individual well concentrations, we also look at the total mass of the tritium, which is based on flow across the site and tritium concentration. Both of those trends are in a downward direction.

Next slide.

This dye test was a very important test. It confirmed several aspects of the hydrology model.

One thing it did is confirm the postulated retention mechanism. It also supported that we would have very early detection capability at the Unit 2 wells.

MEMBER BANERJEE: What was the postulated retention mechanism?

MR. MAYER: If you will permit me, I have a slide to talk about that next, and I will go over that in the next slide.

The site model that I referred to defines the groundwater flow patterns, the direction, and the mass flow rates, which ultimately tie into our ability to quantify the radiological impacts as well as assess the potential for new leaks.

So this dye test accomplished a few things, as I indicated. I will just talk briefly about that.

When we injected the dye, I don't remember the exact time, but it was in 2006. We did a study that was on the order of seven or eight months where, early in the study, we were taking samples daily, then weekly, then monthly. We've got quite a bit of data on this fluorescein tracer test.

What it showed us is that we do, indeed, have conductivity between these two units, and it also showed that the sensitivity of these three wells around the Unit 2 spent fuel pool is actually very high. We actually detected fluorescein dye within a matter of days of injection of the dye.

Then the other thing that we noticed, and we noticed that during the duration of this test, is that there was a timed release element to the fluorescein dye, Okay? It was an instantaneous injection in one day, and then we saw a recurrent kind of injection rate throughout the course of time.

This has actually been observed as recent as the second quarter of 2009, where we still see fluorescein dye that can only be explained by a retention mechanism that is holding onto that dye and slowly releasing it. So that was one of the findings.

This phenomenon that I refer to --

MEMBER RYAN: Wait just a second.

MR. MAYER: Oh, I'm sorry. Go ahead.

MEMBER RYAN: I don't understand that. No idea about the mechanism that is retaining the fluorescein?

MR. MAYER: Yes, I do. I do. I'm going to go to that on the next slide.

The phenomenon that I'm going to go to on the next slide, and go into a little bit more detail on, has been observed at many other sites in the chemical industry. So this is not some kind of radiological tritium phenomenon. Okay?

The next slide.

Oh, I'm sorry. Go ahead, sir.

MEMBER SIEBER: I have a quick question. How deep is bedrock under the surface?

MR. MAYER: Excuse me?

MEMBER SIEBER: How deep is bedrock under the surface?

MR. MAYER: We have bedrock that is anywhere from 10 to 20 feet below the surface. It's fairly close to the surface.

MEMBER SIEBER: The foundation of the

plant is actually down --

MR. MAYER: The plant foundation is down and on the bedrock in the areas.

MEMBER SIEBER: River sediment is 20 feet?

MR. MAYER: Oh, it's well below, yes. The height of the spent fuel pool is at approximately, I think it is at approximately the 70-foot elevation or so, and it drops down to the 15-foot elevation and then drops down into the river at mean sea level.

MEMBER SIEBER: And the flow gradient is always toward the river?

MR. MAYER: Correct, and here's the slide that I will talk about that.

MEMBER SIEBER: Thanks.

MEMBER RYAN: Just one last geology question, if you don't mind. It is fairly fractured bedrock?

MR. MAYER: Yes. Yes. In fact, good lead-in. Okay?

This last slide represents a depth profile cross-section and shows a downward flow that is in the westward direction toward the river, as this gentleman just asked. The plume generally flows under the discharge canal and then returns upward to the river. The mass flow rate across the site is on the order of about 2 to 3 feet per day on average.

One of the things that we focused on here, and I will try to point out a few features that may answer some of the questions that have been asked, what happens here is this is the location of the Unit 2 spent fuel pool. Okay? Then you can see that this is an artist's rendition. It is based on quantitative data from the various wells.

You can see that the flow actually heads westward, which is this way, towards the river. The river actually extends quite deep in this direction. I just don't have the rest of it shown here.

What happens is the water actually -- and how do we know that the water goes down and comes up? The way we know that is through extensive transducer testing, where we look at pressure gradients throughout the well zone field, and then we are able to determine water depths and water flows in terms of upward gradients, as well as downward gradients.

One of the things that was of interest, this was of particular interest to some of the consulting hydrologists from the NRC as they were investigating it, is: how do we know that we are not missing part of the plume going deep? So we do have a number of wells that are as deep as 300 feet, and we have high confidence that we are well-characterizing the plume.

Another point -- and this is to Mike Ryan's question -- the bedrock is a fractured bedrock. What you see, we tried to depict this with the hash marks, but greater than 99 percent of the volume is rock. Less than 1 percent is fracture flow volume. Okay? So it is not like a large pool of water. It is in the bedrock fractures.

MEMBER SIEBER: Is the river itself contributing to the overall plume in this area?

MR. MAYER: Excuse me?

MEMBER SIEBER: Is the river contributing to the overall plume in this area?

MR. MAYER: No. No. We do observe, down very close to the discharge canal, we have observed at certain portions some tidal influence at very near the river, but the rest of the plume is not really influenced by the river.

Okay. The last point, I will talk a little bit about the retention mechanism. Here is what we have. This kind of cutout here shows the spent fuel pool sitting on bedrock, and the pool is above the groundwater table. Okay?

Now when the pool was built, there are a couple of features. It was built on a mud mat, and then that mud mat then extends out to the bedrock, and then it was backfilled.

So there's a couple of points that I would like to make.

First of all, in 1992, at this plant there was a leak that had been caused by damage to the liner during a re-rack job for fuel. That leak existed for about a year and a half.

So what occurred during that leak, concentrated tritium is postulated to have left through the walls, and there was leakage that was observed, and it was since repaired. It was repaired in 1992.

But residual tritium is expected to have migrated into the zones in the mud mat/bedrock interface, and then also into deadend fractures, which, as I have indicated, has been observed in the chemistry industry as well.

Those deadend fractures exist above the groundwater table and in the groundwater table. So those deadend fractures, as precipitation occurs throughout the year, you will get kind of a bleed-and-feed type of a kinetic model going on. I mean it is not going to be a clean, simple, one-compartment, first-order kinetic model because there are multiple compartments, depending on whether it is deadend fracture or this, but, conceptually, that is the process. Okay?

Then, again, another important point is that in 2007 we did identify, I will describe it as a pinhole. It was about a 1/8th inch kind of, for lack of a better term, sliver in a weld point on a plug weld in the wall. Okay? We inspected 100 percent of the transfer canal because that was a good microcosm of the entire pool, and we found this one location that did have a through-wall leak. We confirmed that with vacuum testing.

We repaired that in November. Okay? We have seen, since that time, a trend downward in the concentration, which, if you've stopped leaks, you would expect the trend to go down. That is what we have observed.

So these deadend fractures and the pockets between the pool and the wall are the retention mechanism that continues to feed the plume on a downward-trending basis.

So, in summary, I guess what I would like to leave you with is that our understanding of the groundwater behavior and its relation to leak detection and monitoring is very robust, very robust. There is no challenge to public health and safety from the perspective that the dose significance of this particular situation is extraordinarily low, many times below 1 percent of the effluent limits.

We do have a very robust, long-term monitoring program in place which continues to trend this data. If any changes should occur, we will know about it.

So I will open it up now for further questions.

MEMBER BANERJEE: Let me ask you about the retention mechanism to start with.

MR. MAYER: Yes.

MEMBER BANERJEE: You say that the retention is in a series of, let's say, some network of deadend fractures. How does it get in there, if it is deadend? Is there a flow into this structure?

MR. MAYER: Well, you know, I will confess that I'm not an expert hydrologist, but in discussions --

MEMBER BANERJEE: It doesn't have to be a expert.

MR. MAYER: In discussions with a hydrologist, this is what --

MEMBER BANERJEE: There is no flow into it?

MR. MAYER: There is no flow in the deadend fractures, but there will be capillary movement in the deadend fractures. That is well-documented.

So here's what happens: the tritiated water leaves the pool. It goes into somebody's construction voids, or whatever you want to call them, in the bedrock near the concrete floor interface, and then, also, you will get capillary suction into the deadend fractures.

As water moves by the deadend fractures, what happens, and has been observed, is that you will have a highly-concentrated tritium in the deadend fracture will then mix with the low concentration, and then, just through capillary action and Brownian diffusion, you will get movement into those zones.

MEMBER BANERJEE: So the postulate is that you fill these, which were maybe filled with air or something, by capillary reaction, is that it?

MEMBER RYAN: I guess I will offer you my understanding, Sanjoy, and maybe it will help.

Tritiated water, take a millimeter --

MEMBER BANERJEE: We're also talking about the dye.

MEMBER RYAN: Well, skip the dye for the minute, but tritium is going to seek the hydrogen pool in front of it. So, if you have a pour that is filled with water, even though it is a deadend pour, and tritium water comes to the edge of that deadend pour, it is going to equilibrate with the hydrogen pool in that fracture.

MR. MAYER: Correct.

MEMBER RYAN: So tritium, I understand well that it seeks the hydrogen pool that is in front of it. It does it by proton exchange.

MEMBER BANERJEE: All right. Yes. So there's some sort of enhanced diffusion, or whatever you want to call it.

MEMBER RYAN: Yes.

MEMBER BANERJEE: But how do you explain the dye in that?

MEMBER RYAN: I don't know. I can't give you the same answer.

MEMBER BANERJEE: So they see the same potential mechanism, right?

MEMBER RYAN: I would think, but I don't know enough about fluorescein dye to tell you.

MR. MAYER: I can't answer. I can't

answer that specifically, other than we've observed the phenomenon. The data correlates very strongly with the retention theory.

Part of it, also, is that there are some areas that are voids that are in the construction fill that you could have residual dye and other things that would just reside there. Because, remember, this is not immersed in the groundwater. This is above the groundwater table.

So what happens is that the water will flow down the side of the structure, past whatever may be retained there, and then it moves down the fractures in the rock to the groundwater. So the pool is actually above the groundwater table.

So you have this residual area that is in a zone that, while it is moist in the groundwater table -- it is called the vadose zone -- it doesn't have free-flowing water. So that when the water moves through that vadose zone, it picks up that tritium or fluorescein dye, and it carries it down into the actual groundwater table, which is where we see it.

MEMBER BANERJEE: I have noticed that you have a retention mechanism because you see it.

MR. MAYER: Yes.

MEMBER BANERJEE: You see it with the dye.

Whether the explanation you are offering is the correct one is hard to see because, I mean, by the explanation that Mike gave, I can see that there is an accelerated diffusion of the tritium, but I don't see that there should be an accelerated diffusion of the dye.

MEMBER RYAN: I guess, to me, the action for me is with the tritium data. It is not with the dye data. The dye data is how --

MEMBER BANERJEE: The dye data has to be consistent.

MEMBER RYAN: Yes, and it is helpful to describe where you want to put your monitoring wells. But once your monitoring wells are in place and you are looking at the contaminant of interest, and you have a contaminant to easily measure, I tend to set the dye information aside. That was helpful at --

MR. MAYER: Quite frankly, Mike, just to elaborate on that a little bit, that is exactly what we have done. The tracer test had several roles, one of which was principally -- you know, it wasn't initially to validate the retention mechanism. It just so happened that it did provide additional data.

It was to do precisely what Mike had indicated, which was, hey, we think we know where the tritium is going, based on the monitoring that we have done. And we believe we know the right depths and locations to put the wells. Let's do some additional tracer tests data to confirm where we think we need to put the wells.

Then tritium, as Mike has indicated, is probably one of the best tracers you can have in terms of its movement through the soil, through the soil and bedrock. So that is what we base it on.

MEMBER BANERJEE: So are you confident that, let's say, there was a leak and a lot of it was retained, would you be able to detect it or would there be a situation where you could have a lot retained which would sort of come out without your early knowledge of it?

MEMBER RYAN: I guess, because it is tritium -- are you asking me or the applicant?

MEMBER BANERJEE: Let's ask the applicant.

MEMBER RYAN: Okay.

MR. MAYER: I can answer that question.

MEMBER BANERJEE: Go ahead.

MR. MAYER: We have not tried to quantify the amount of water that was retained. Okay? You know, we have had some discussions on it.

We believe that, actually, on a percent

basis, the amount of tritiated water that would be retained is actually fairly low. The reason for that is because the tritium concentrations are very, very high relative to what we see in the groundwater. So it only takes gallons of tritiated water to be available. This is not a significant amount of water.

I mean, just to put things in context, the kinds of concentrations that we see downstream, say, are well below 100,000 picocuries per liter, just to put it in context.

The concentration of the tritium in the pool is 30 million picocuries per liter. So it takes a very low level of volume to be able to support that type of phenomenon.

Yes, sir?

MEMBER SIEBER: You take regular samples from the river?

MR. MAYER: Yes.

MEMBER SIEBER: Have you found tritium in the river?

MR. MAYER: No.

MEMBER SIEBER: Do you have reasonably close offsite, outside the inner controlled area, wells?

MR. MAYER: Yes, we do, sir.

MEMBER SIEBER: If the gradient is from the IP2 fuel pool to the river, have you found tritium outside the inner controlled area that is not a part of that plume?

MR. MAYER: We have not, and we specifically looked at that as one of the earlier parts of the investigation.

MEMBER SIEBER: So you are concluding, I'm concluding --

MR. MAYER: Yes, sir.

MEMBER SIEBER: -- and you can confirm or deny, that there is not a pathway to human beings from this leak other than what's in the under control area property you own?

MR. MAYER: That's correct, although the water does go to the river. Yes, but you are correct, it does not go off our site into the offsite groundwater zones.

MEMBER SIEBER: In concentrations above the --

MR. MAYER: In concentrations that are detectable above our lower limits of detection, which are very low. That's correct, sir.

MEMBER SIEBER: Do you expect it to stay that way?

MR. MAYER: Absolutely. And in fact, I won't go back to the previous slide, but I mentioned boundary wells. We actually have wells that we put for conservatism on the southern end of the site that actually are there for that specific purpose. They are on our site, but prior to going offsite. Those consistently are not detectable.

MEMBER SIEBER: Well, the point of my question is identifying pathways to people and animals. It would appear from these drawings and your analysis that, other than what occurs on site property you own, there is none.

MR. MAYER: That's correct.

MEMBER RYAN: If I could just turn your attention to the figure that is up on the screen now, if I am reading the hash marks right, there is a 5 to 10 thousand band that is fairly wide that seems to go across the river, is that right?

And what would you consider to be background in the groundwater without the tritium added?

MR. MAYER: Tritium background is less than a thousand.

MEMBER RYAN: Okay. And again, I think just for reference sake, the drinking water standard is 20,000 picocuries per liter --

MR. MAYER: Correct.

MEMBER RYAN: -- just so people get a sense of what that means. That is a committed dose of 4 millirem per year if that is the only source of water.

So those are very low numbers in my view of that.

MR. MAYER: That's correct.

MEMBER RYAN: I guess, in summary, I am going to try to summarize my understanding, and tell me if I have missed the mark. You have, because you have done both dye tests initially and then tritium tests or tritium tracing, as you begin and develop your monitoring network, you feel you have a pretty comprehensive understanding of tritium direction and flows?

MR. MAYER: Absolutely.

MEMBER RYAN: At this point, you feel like you've got a robust monitoring network to which you will get no surprises from tritium popping up somewhere else, is that your view?

MR. MAYER: Correct. That is our view, yes. That's correct.

MEMBER RYAN: And that you have

concentrations that are below standards or requirements anywhere where it leaves your site?

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

MEMBER RYAN: Thanks.

MEMBER BANERJEE: I have a question regarding the placement of your monitoring wells. This concentration profile that you show, the profiles you show there, there are significant high-concentration regions where there is no sampling, right?

So, if you look at, say, the second well to the right, it is near the surface, and then there are two wells after that which are fairly close to the surface, but the plume is going very deep. At least that's what your calculations show.

Do you have any evidence directly that this is actually the shape of the plume?

MR. MAYER: What you are seeing --

MEMBER BANERJEE: Or is this a calculated shape?

MR. MAYER: Well, this particular -- yes, it's calculated. I mean, you know, it has to be calculated because we have a finite number of wells. But that is the calculation that is based particularly on the input from the transducer data, as well as the sampling of that. Because, remember, the sampling is two-dimensional as well as depth. So we do have a pretty robust X and Y coordinate that we are looking at.

We do believe we have found the plume center lines, and we do believe that we've got wells sufficiently deep to characterize it. That is a model to depict our best understanding of plume shape.

As Fred just reminded me, we have had the USGS and other experts evaluate this data along with us.

MEMBER RYAN: What's the total number of wells you have in your program? Fifty?

MR. MAYER: Oh, I believe it is 43.

MEMBER RYAN: Okay.

MR. MAYER: It is a large number of wells.

MEMBER RYAN: So 43 wells, packed at various elevations within each well --

MR. MAYER: We have well in excess of 100 zones that we sample.

MEMBER RYAN: A hundred zones of sampling?

MR. MAYER: It's very, very extensive.

MEMBER RYAN: Something that's what, a few acres?

MEMBER BANERJEE: And they are not all shallow, the type that you are showing?

MR. MAYER: That is correct. In fact, most of them are multi-level wells that are deep. We do have some shallow wells, but we have deep wells as well.

MEMBER MAYNARD: This has all been good discussion, and it is important to our understanding. But we are here for license renewal. Part of this is a current licensing basis issue being resolved and discussed, and everything.

I think it is important for us to focus on, are the efforts in place sufficient to provide the type of monitoring needed for the extended period of operation?

And the other thing we need to just touch on a little bit, to make sure we don't lose sight of it, we have talked about the plume. It is also the structural integrity of the spent fuel pool to be able to withstand an earthquake and stuff.

The staff has evaluated this, and the applicant has to provide assurance that the structure is still capable of performing its intended design functions. I think that is the important part for license renewal, is: are those efforts still going to be adequate for monitoring in the future, to make sure it's the structural integrity, too.

VICE CHAIRMAN ABDEL-KHALIK: Well, you indicated that you had a pinhole leak which you plugged. Did you do a root cause to find out the reason for that pinhole?

MR. MAYER: Yes, we did. The conclusion was that it was during construction, during original construction, a defect when it was being welded to the wall.

VICE CHAIRMAN ABDEL-KHALIK: So the conclusion is that there is no ongoing mechanism that may cause future pinhole leaks?

MR. MAYER: That is absolutely correct. Yes, I didn't get into details, but we did microbial-induced corrosion tests. We did visual tests. We did ultrasonic testing to address those very specific questions.

Our conclusion is that, no, there is no other cause for concern of an active leak.

MEMBER MAYNARD: Any other questions for the applicant? We do need to reserve some time here for the staff.

MR. DRAKE: If we could, I would just like to spend a minute on this calculation as it relates to containment penetration cooling.

MR. ORLANDO: The calculation assumed that we have a pipe diameter of 2.3 feet in diameter; we have approximately a half-inch-thick insulation on that pipe. Then we have an air gap of a couple of inches.

VICE CHAIRMAN ABDEL-KHALIK: Excuse me. Could you repeat that thickness of the insulation again?

MR. ORLANDO: The insulation is .458 feet thickness.

VICE CHAIRMAN ABDEL-KHALIK: Okay.

MR. ORLANDO: And there is approximately 2.4 feet between penetrations, and the concrete thickness that we assumed was 4.56 feet thick.

Now the thermal conductivity of the concrete is .54.

VICE CHAIRMAN ABDEL-KHALIK: So, when you say the concrete reached 300 degrees, are you talking about the surface temperature of the concrete?

MR. ORLANDO: Yes.

VICE CHAIRMAN ABDEL-KHALIK: Okay. So the time-constant of concrete doesn't really enter into this. So you are saying that it takes 58 days to reach a temperature of 300 degrees by conduction through a 6-inch layer of insulation?

MR. ORLANDO: That's correct. That is what the calculation comes -- that is the conclusion of the calculation.

MR. DACIMO: We will supply you the methodology and the calc.

VICE CHAIRMAN ABDEL-KHALIK: Thank you.

MEMBER MAYNARD: Okay. Any other questions for the applicant here?

MEMBER BANERJEE: But it wasn't hours, going back to my original? I thought it was an incredible number.

MEMBER MAYNARD: Why don't we go ahead and get the staff up here and let them provide their presentation? If there is time at the end, we can go back to any of these questions that we have.

MR. HOLIAN: While the staff is getting situated, this is Brian Holian. If we are ready to go, I've got a couple of introductory comments and then we will go.

I introduced Kim Green and our Regional Inspector, Glenn Meyer. Also, there is Dave Wrona, the Branch Chief responsible for the Indian Point review.

Before Kim takes over the presentation, I just had a couple of comments.

One, there's many numerous other NRC staff and Branch Chiefs here to respond to questions, not only on the topics we are going to highlight, but other aspects of the SER. So I just wanted to recognize that.

Secondly, I would just like to recognize that Indian Point is a hearing plant. So that is just an item for your information. There are several items that the SLB is still reviewing.

Also, for Indian Point, the environmental review is still ongoing. So that tritium discussion that we just had, that is an important part that is covered in our draft environmental DSEIS. We are still finalizing the final SEIS. The DSEIS is out for public comment. Those comments have come in, and the staff is responding to those in the final environmental review.

I wanted to mention one other item. That is just schedule. You know, the NRC staff does advertise schedules for license renewal reviews, 22 months and 30 months.

I will mention, on Indian Point and a plant like this, the staff took four to five additional months during the safety review process.

So I just wanted to highlight that. That is an indication. We had several onsite audits. Glenn Meyer will probably mention that.

We revisited issues. This was one plant we even took a harder look at operating experience. We always look at operating experience as a part of license renewal reviews, but we have been focusing on that for really the last year, year and a half. You will see some of that in the Safety Evaluation Report.

On one aspect, I think Dr. Maynard picked it up, on the licensee's response on containment, we actually covered leakage; you know, the no safety significance. I think the staff would also question that aspect of the slide. I think it is minimal safety significance. That is one area on operating experience where the staff dug back and looked at some of the concrete issues and containment or other areas that we highlighted.

We agree it is minimal safety significance, but it is worthwhile for the staff to pulse those areas, to check, one, where is water going, and what kind of degradation might be occurring or could be occurring, or what process would we need to put in place for the extended period.

So, with those items, I will turn it over to Kim Green.

MS. GREEN: Good morning. As Brian mentioned, my name is Kim Green and I am the Safety Project Manager for the Indian Point license renewal application.

At today's meeting, I will briefly cover the staff's review of the license renewal application. Then Glenn Meyer will discuss the results of the onsite license renewal inspections. Then I will follow up with some items of interest, including the revision of the buried piping and tanks inspection program, the metal fatigue analyses, and the fatigue-monitoring program, the flow-accelerated corrosion program, and the Charpy upper-shelf energy criteria.

By letter dated April 23, 2007, Entergy, or the applicant, submitted the license renewal application for the renewal of the Indian Point Nuclear Generating Units 2 and 3.

During its review, the staff issued 121 requests for additional information. It also conducted five audits, during which it asked 272 audit questions.

The Region conducted four onsite inspections, the results of which Glenn Meyer will cover shortly.

The Region issued its findings in an inspection report which was issued on August 1st, 2008.

The staff documented its initial findings in the Safety Evaluation Report with open items, which was issued on January 15th, 2009. In the SER, the staff identified 20 open items. I would like to characterize 13 of those as items that were just clarification in nature, and the other seven required additional information or commitments from the applicant.

By letters dated January 27th, May 1st, and June 12th, the applicant submitted additional information and/or commitments to address the open items. Based on a review of the information provided, the staff was able to close out all 20 of the open items. The staff documented its final findings in the Safety Evaluation Report which was issued on August 11th, 2009.

In the SER, the staff concluded that the requirements of 10 CFR 54.29(a) have been met. That is, that actions have been identified and actions have been or will be taken with regard to managing the effects of aging during the period of extended operation, on the functionality of structures and components, and the identification of time-limited aging analyses for review, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the current licensing basis.

At this point, I will turn the presentation over to Glenn Meyer.

MR. MEYER: Good morning.

I would like to briefly summarize the license renewal inspections. We did go through the details with the Subcommittee, and I am certainly willing to address any questions.

We sampled 28 of the aging management programs during our inspection. On the programs themselves, we found seven programs which had concerns, but which Entergy addressed by amending their license renewal application. I would characterize the resolutions as fairly straightforward.

We were also involved in the containment exterior concern, the exposed rebar, where both our structural and non-destructive examination -- experienced inspectors looked at the evaluation and the monitoring in the future, and that was addressed in Commitment 37.

As mentioned, we came back to look at the Unit 2 station blackout, Appendix R, Diesel, that was newly installed following its operational testing to confirm both the implementation of the diesel and its incorporation into the license renewal application.

At that time, Entergy did open up one of the electrical cable vaults that we inspected. During the spring outage, we also went into the Unit 2 containment to look at the liner-to-seal degradation at that point.

The last part of our inspection was the scoping of non-safety-related equipment. We felt that they had done an adequate job on that.

MEMBER STETKAR: Glenn, can I ask you just a couple of brief questions before you get into more of the detailed discussion?

One question was a followup on the isolation valves for the feedwater-regulating bypass valves. I know there are some questions about whether they were in scope as a safety-related component or non-safety. I understand that they are non-safety-related, and I understand the basis for that.

The question was, I had a question at the Subcommittee meeting regarding confirmation that, indeed, both sets of isolation valves on both units were included in scope. Everything that I have read doesn't confirm to me that both isolation valves on both units are in scope.

I was going to ask the licensee, but you gave me an opportunity because your last bullet says non-safety-related issues. Are they both in -- the valve numbers are BFD 5 and BFD 90, respectively.

MR. MEYER: Right.

MEMBER STETKAR: And there was a question that originally in the discussion both sets of valves were included in scope on Unit 3, yes, Unit 3, I believe, and only one set of valves was on Unit 2. So I just wanted to confirm that both sets of valves are, indeed, in scope on both units.

MR. MEYER: I don't have that information right now. The technical reviewer and Entergy may be able to --

MEMBER STETKAR: Anybody from Entergy, quickly?

MEMBER MAYNARD: You need to get to a microphone.

MEMBER STETKAR: I'm sorry about this. I was going to ask you, but we wanted to get people shuffled around quickly.

MEMBER MAYNARD: And identify yourself,

please.

MR. CONROY: Yes, my name is Pat Conroy. I'm the Director of Nuclear Safety Assurance for Indian Point. I understand the question you are asking.

There is different design and licensing bases associated with the BFD 90 valves with respect to Unit 2 and Unit 3. Unit 2 has specifically been analyzed with respect to a steamlined break-type accident not crediting the BFD 90 valves to operate.

So, actually, if there is a difference in the design basis between the two plants, that explains the scoping question, I believe, that you are referring to.

MEMBER STETKAR: So, if I understand you correctly, there is actually a difference of what is in scope between the two units?

MR. CONROY: I believe that to be the case.

But, Alan, do you want to respond?

MR. COX: This is Alan Cox with the license renewal team, and I can add a little clarification to that.

When you look at the scoping for A2, we are also looking at fluid-filled systems that are in the turbine building that could affect other systems. Both of these, both sets of valves on both units are going to be in scope for A2 because of their potential to affect other --

MEMBER STETKAR: That is good. Thanks. That is why I asked, because of the A2. Thank you.

One last one for you --

MEMBER MAYNARD: Did you have something you wanted to add?

MS. STAGERDOT: Bob Stagerdot. I reviewed the RAI response and did confirm that those lines are in the room, and all lines in that room are in scope under A2.

MEMBER STETKAR: Good. Thank you.

This may too detailed, and just tell me if it is, so we can keep on schedule.

I'm still confused about exactly where the boundary of the offsite power or a station blackout scope is out in the switch yards. Every time I read things, the boundary seems to change just a little bit.

I was wondering if anybody had something like exact breaker numbers.

MR. MEYER: I don't have that information, but, again, we will turn to the reviewers and Entergy.

MEMBER MAYNARD: Well, to keep the presentations on schedule, let's table that. Do you have it quickly?

MR. McCAFFREY: I'm Tom McCaffrey. I'm the Manager of Design Engineering.

We did present the drawing during the Subcommittee, and it has the breaker numbers listed on there as basically 138 kV supply breakers down from Buchanan.

MEMBER STETKAR: Okay.

MR. McCAFFREY: Those breaker numbers were on that drawing we provided during the Subcommittee meeting.

MR. HOLIAN: And this is Brian Holian, Director of License Renewal.

I think we discussed at the Subcommittee station blackout as an open item. At that time, the staff was pushing, I think I stated it there, the boundary kind of generically at all the plants out to the first breaker in the switch yard.

The staff has since retracted that position. It was an interim staff guidance. We have one currently that says, typically, they are included. The staff was trying to firm that up. It does depend upon their current licensing basis, that they are currently, each plant individually -- it is something the staff still looks at. We asked additional questions. We were satisfied with the design and what they have put in scope at Indian Point.

MEMBER STETKAR: So you settled at the 13.8?

MR. HOLIAN: Yes.

MEMBER STETKAR: Okay, thank you.

MEMBER MAYNARD: Okay. Go ahead.

MR. MEYER: That concludes the discussion of the regional inspections, if you had any questions. Otherwise, we will return to Kim.

MS. GREEN: Okay. For the remainder of the staff's presentation, I would like to cover a few of the items that are of interest to the ACRS.

The first one is the recent modification to the applicant's buried piping and tanks inspection program.

As stated in the license renewal application, the applicant identified the buried piping and tanks inspection program as a new program. Entergy also stated in the LRA that the program will be consistent with GALL AMP XI.M34, which is the buried piping and tanks inspection program.

The GALL AMP recommends that inspections be performed to confirm that coating and wrapping are intact as an effective method to ensure that corrosion of external surfaces has not occurred and the intended function is maintained, and that buried piping and tanks should be opportunistically inspected whenever they are excavated during maintenance.

When opportunistic inspections are conducted, they should be performed in areas with the highest likelihood of corrosion problems and in areas with a history of corrosion problems within the areas made accessible to support the maintenance activity.

Prior to entering the period of extended operation, the applicant should verify that at least one opportunistic or focused inspection was performed within the past 10 years. And upon entering the period of extended operation, the applicant should perform a focused inspection within 10 years, unless an opportunistic inspection occurred within this 10-year period.

The GALL AMP also recommends that the applicant's plant-specific operating experience be further evaluated for the period of extended operation.

In February of 2009, the applicant discovered a leak in the IP2 condensates return line.

As a result of this operating experience, and at the request of the NRC, the applicant amended its program.

In its July 27th letter to the NRC in which Entergy described the amended program, it stated that it plans to perform 51 inspections of buried piping and/or tanks at IP2 and IP3 prior to entering the period of extended operation.

Entergy also committed to perform periodic inspections during the period of extended operation using inspection methods with demonstrated effectiveness.

Entergy will base the number of inspections and the frequency on the results of the inspections that are planned prior to entering the period of extended operation, other applicable industry operating experience, plant-specific operating experience, and the classification of piping segments in tanks and corrosion factors.

The applicant plans to classify the in-scope buried piping segments in tanks as high, medium, or low impact of leakage based on the safety classification, the hazard posed by the fluids in the piping and tanks, the impact of leakage on reliable plant operation.

Corrosion factors that they will consider include piping or tank material of construction, soil resistivity, drainage, presence of cathodic protection, and the type of coating.

The staff concluded that the applicant's amended program will be adequate to manage the effects of aging for buried piping in tanks.

The next topic I would like to discuss is metal fatigue. In the license renewal application, the applicant stated that it projected the 60-year environmentally-adjusted fatigue cumulative usage factors for the NUREG CR-6260 locations, except for two locations at Indian Point II and three locations at Indian Point III.

This is because Indian Point II and Indian Point III are ANSI B31.1 plants, and the licensee was not required to calculate cumulative usage factors for the same locations that were later required by the ASME code.

Entergy has committed to manage aging for all NUREG CR-6260 locations, including the five locations currently without environmentally-adjusted CUFs, in accordance with 10 CFR 54.21(c)(1)(iii).

Next slide.

The program that the applicant plans to use to manage aging for the reactor coolant pressure boundary is the fatigue monitoring program. In the license renewal application, the applicant stated that the fatigue monitoring program is consistent with the GALL AMP XI.M1, which is metal fatigue of the reactor coolant pressure boundary.

The GALL AMP, as well as the applicant's program, addresses the effects of the coolant environment on component fatigue life. The program is based on monitoring and tracking the number of critical thermal and pressure transients for critical reactor coolant system components. These critical components include the ones identified in NUREG CR-6260.

The program is designed to prevent the cumulative usage factor from exceeding the design code limit of 1.0 and, when considering the effect of the reactor water environment, will provide adequate margin against fatigue cracking of reactor coolant system components during the period of extended operation.

The program also provides for periodic updates of the cumulative usage factor calculations. The applicant also incorporates action limits. These are limits that trigger corrective actions if the action limits are reached.

If an action limit is reached, the program directs the applicant to take appropriate corrective actions, which includes repair/replacement, or a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded during the period of extended operation.

Based on its review of the applicant's program, the staff concluded that the effects of aging will be adequately managed during the period of extended operation.

MEMBER SHACK: Now does that mean they are going to go off and do CUF calculations by ASME Code for the 31 remaining locations that they didn't do in the original design?

MS. GREEN: Yes, they have a commitment to do that.

MEMBER MAYNARD: Now it is my understanding that, well, they are relying on the fatigue monitoring program here, but based on current projections, there are some components or some sections that may exceed its limit if nothing changes in the current operation. So they are depending on the fatigue monitoring program to identify, keep track of that, and, if necessary, take action before exceeding that limit, is that correct?

MS. GREEN: That is correct.

MEMBER MAYNARD: Okay. What kind of look was done at their metal fatigue monitoring program? Was that inspected or audited, or did somebody take a look at that?

MS. GREEN: Yes, that was audited during one of our onsite audits.

MEMBER MAYNARD: Okay. And the auditors felt confident that that program would identify any issues before exceeding that limit to give time for action to be taken?

MS. GREEN: Yes, that is my understanding.

MEMBER ARMIJO: What is the action limit? Is that a fraction of the CUF of one? Or what is that?

MS. GREEN: I would have to ask On Yee, the staff.

MR. YEE: This is On Yee of the staff.

During the audit, it was asked what the action limit was. If I recall correctly, they would take two times the number of cycles that occurred and add that onto the crew cycles. If that exceeded the design cycles, then they would take corrective actions.

MEMBER ARMIJO: Okay. I understand.

Thank you.

MS. GREEN: I would like to move on to the flow-accelerated corrosion program and the operating experience.

During the ACRS Subcommittee meeting in March, an ACRS member questioned why the inspection frequency did not change for instances where the minimum measured wall thickness was near or below minimum acceptable wall thickness. At that time, the staff did not answer the ACRS member's question. So I would like to try to address that now.

During the audit, the staff questioned the applicant about the incidences of wall thinning that were reported in the license renewal application. Specifically, there was an IP3 vent chamber drain piping, IP3 high-pressure turbine drain piping. There is a 2-inch diameter line and a three-quarter-inch diameter line, and the IP2 steam trap piping. These were, I think, the four cases that the ACRS member was referring to in the staff's audit report.

In response to the audit question, as well as a few others that were related to the flow-accelerated corrosion program, the applicant stated that the piping and affected components were included in the flow-accelerated corrosion program prior to the inspections. As the wall thinning of these components was discovered, the applicant replaced the components with like-for-like materials or FAC-resistant materials.

The applicant also stated that, if a component is discovered that has a current or projected wall thickness less than the minimum acceptable wall thickness, then additional inspections of identical or similar piping components in a parallel or alternate train is performed to bound the extent of thinning. When the inspections of components detects significant wall thinning, then the sample size for that line is increased.

One of the examples I would like to talk about to explain this is the IP3 vent chamber drainpipe thinning. During the refueling outage 13, Entergy did an inspection of an elbow immediately downstream of the moisture separator reheater and found wall thinning less than the minimum acceptable wall thinness, requiring replacement of the elbow.

Based on the results of that inspection, the applicant performed a sample expansion to determine the extent of condition for this pipe thinning. The expansion included corresponding components on the other moisture separator reheaters with a configuration similar to that of the elbow displaying the thinning.

Entergy then performed four additional inspections. These inspections also found wall thinning less than the minimum acceptable thickness requiring replacement of the components.

The sample expansion was continued until no additional components were detected with significant wear. Entergy performed four additional inspections downstream of the worn elbows. The results of this expansion did not find significant wear, and the sample expansion was then terminated by Entergy. The applicant updated and adjusted the Checkworks model to incorporate the inspection data.

MEMBER BROWN: Before you go on, I guess I asked that question. So I will ask it again.

I'm trying to draw a conclusion from your answer that, No. 1, they replaced them with more erosion-resistant or flow-accelerated corrosion-resistant materials when they did the replacements. Is that correct?

MS. GREEN: For that particular line, they were planning to replace with Chrome-Moly, but for other lines --

MEMBER BROWN: That doesn't mean anything;

I'm not a metallurgist. Is it better or worse?

MS. GREEN: It's better.

MEMBER BROWN: Okay. Thank you.

MS. GREEN: Sorry.

That is more FAC-resistant. For other lines, they did a replacement of like-for-like material.

MEMBER BROWN: Okay. The second question was they had found the wall thicknesses considerably less. There were a number of other locations also that had less than the minimum acceptable wall thickness.

So the second part of the question about, if they just did it like-for-like, what do you do to your inspection process to make sure you don't encounter a circumstance that you now find you've got less than minimum wall thickness again, which means increased frequency? That part I didn't understand the answer. Or was there an answer?

MS. GREEN: I am not a flow-accelerated corrosion program expert. So I would have to ask Matt Yoder from the staff to address your question.

MEMBER MAYNARD: I believe we have somebody coming to answer that.

We need a portable microphone, I believe.

MR. YODER: Okay, Matt Yoder, NRR staff.

So, when these instances were found, the data is then fed back into your Checkworks model. So that, for future planning of inspections and UT, your model is going to predict a greater wear rate at those locations, and it should then be scheduled for more frequent UT inspection.

MEMBER BROWN: Okay. So there was an explanation of the Checkworks thing in, I think, the applicant's answer back, which I read, not being a Checkworks expert.

So the point being that the information of the increased wear rate is then fed back into this model, so that it gets into a periodic inspection that is more frequent than before? It is not like you go change a chart somewhere, but you do it based on the predictions of the model?

MR. YODER: That is correct. The model is continuously updated with actual field data.

MEMBER BROWN: Okay. All right, thank you.

MEMBER SHACK: How long has the Checkworks program been in place at Indian Point?

MR. YODER: I will have to defer to Entergy.

MR. AZEVEDO: My name is Nelson Azevedo. I'm the Supervisor of Programs at Indian Point.

We first started using the Checkworks models when it was first issued by EPRI, which I believe was the early nineties. I don't know the exact date.

MEMBER SHACK: It hasn't reached steady-state yet?

MEMBER MAYNARD: Okay, let's go.

MS. GREEN: Okay. I would just like to cover briefly the staff's evaluation of the applicant's flow-accelerated corrosion program.

In the license renewal application, the applicant stated that its flow-accelerated corrosion program is consistent with the GALL AMP XI.M17 with one exception, that exception being the use of EPRI NSAC-202L, Revision 3, in lieu of Revision 2, which is recommended in the GALL report. The staff reviewed the exception and found that the use of Revision 3 is acceptable.

Based on the staff's audit and review, it determined that all other program elements are consistent with the GALL report AMP.

The applicant's program includes updated inputs for the power operating parameter changes with steam flow rates and temperatures and such. It also identified piping systems and components that are currently the most susceptible to the loss of material due to FAC.

Corrective actions that are in place include re-evaluation, repair, or replacement. Based on the review of the applicant's program, the staff concluded that it is adequate to manage the effects of aging, and therefore, acceptable.

During the March ACRS Subcommittee, ACRS Member Brown asked the staff to explain the various criteria for Charpy upper-shelf energy. At the time, the staff did not provide a full explanation, and therefore, Chairman Maynard asked us to provide an explanation of the criteria, which I will attempt to do now.

10 CFR 50, Appendix G, requires that reactor vessels must maintain Charpy upper-shelf energy values of no less than 50-foot pounds, unless it can be demonstrated that lower values of upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of Section 11 of the ASME Code.

Appendix K of the ASME Code, Section 11, and ASME Code Case N-512 provide criteria for demonstrating that reactor vessels with Charpy upper-shelf energy values less than 50-foot pounds have margins of safety against fracture equivalent to those required by Appendix G of Section 11 of the ASME Code.

The NRC has regulatory guidance on how to perform ASME Code equivalent margins analysis for upper-shelf energy. This guidance was initially documented in Draft Guide 1023 and is currently documented in Regulatory Guide 1.161.

Regulatory Guide 1.99, Rev 2, provides guidance for determining the impact of neutron irradiation on Charpy upper-shelf energy.

The applicant has projected the Charpy upper-shelf energy at the end of the period of extended operation in accordance with Regulatory Guide 1.99, Revision 2. Each unit has a limiting plate where the upper-shelf energy is less than 50-foot pounds. In IP2, it is 48.3-foot pounds, and in IP3, the value is 49.8-foot pounds.

As required by 10 CFR 50, Appendix G, and ASME Section 11, Appendix G, the applicant performed an equivalent margins analysis. The applicant used WCAP-13587, Revision 1, as the basis for its equivalent margins analysis. That WCAP is entitled Reactor Vessel Upper-Shelf Energy Bounding Evaluation for Westinghouse Pressurized Water Reactors.

That WCAP demonstrated that Westinghouse four-loop plants can meet the ASME Code requirement of 43-foot pounds for upper-shelf energy. Since IP2 and IP3 are both Westinghouse four-loop plants, the WCAP is applicable.

The analyses in the WCAP-13587, Rev 1, were performed in accordance with ASME Code Case N-512 and Draft Guide 10.23, which, as I mentioned previously, provide criteria or guidance for demonstrating how the reactor vessels with Charpy upper-shelf energy values with less than 50-foot pounds have margins of safety against fracture equivalent to those required by ASME Section 11, Appendix G. These analyses would also satisfy Appendix K of ASME Code Section 11 and Regulatory Guide 1.161.

Based on its review, the staff determined that IP2 and IP3 reactor vessels will satisfy the Charpy upper-shelf energy requirements of 10 CFR Part 50, Appendix G, at the end of the period of extended operation. That is based on the fact that the analyses in the WCAP are applicable to IP2 and 3. The staff approved the WCAP in April of 1994.

The Charpy upper-shelf energy values are greater than the minimum allowable of 43-foot pounds, which was demonstrated to be acceptable in WCAP-13587, Rev 1.

This concludes the staff's presentation, if there are no other questions.

MEMBER MAYNARD: I want to go back to another item or two here, but see if there are any questions for the staff right now.

CHAIRMAN BONACA: I do have a question.

On page 8, buried piping and tanks inspection program, you know, the report recommends one inspection prior to the PEO and one during the first 10 years of the PEO. Then you had the recent developing experience of the leak in the IP2 condensate return line.

In response to that, they have committed to 51 inspections. I am trying to understand how they went from a minimum scope of that nature to such a large number of inspections. I mean, do they know something, in other words --

MR. HOLIAN: This is Brian Holian, Director of License Renewal.

Kim, you can add to it.

That was one item I wanted to highlight, kind of on the applicant's, Entergy's response to operating experience.

On the buried piping issue, and really on two issues I was going to highlight, one you just saw from their application. They were very proactive in responding to two particular areas that you saw, one on their aspect, which was the tritium groundwater monitoring program. That has gone on for a couple of years. It received a lot of public attention up there, which is one driver.

I also wanted to mention that the region itself put additional inspection resources for independent verification under the reactor oversight process of that whole process, and that didn't get highlighted here. But there are several special inspection reports out on groundwater monitoring.

On buried piping, there has been some recent agency action along that aspect. We have seen a little bit of an uptick in buried piping occurrences here. When it happened for Indian Point, when it was right at the license renewal aspect, that is an opportune time to shine some light on their program.

Besides the light that we were shining on it, I think independently they, themselves, were looking at their program onsite. So part of that is not driven necessarily by the one occurrence where they decided to dig up more buried piping.

I think what they are seeing is it is an opportune time to commit to that anyway, to understand what they have going on in their site.

The root cause for them, also, was a backfill issue, which on two different occasions, the way they did backfill on original construction laying these lines was larger-sized rocks that they think have damaged two of those pipes. So that leaves the question open, what other areas might be damaged by that type of backfill?

So I think the licensee was, one, very good in kind of responding to that operating experience by itself. I think the NRC staff is shedding some more light on, is GALL sufficient really for plants?

So you might have seen, just within the past week here, the Chairman of the NRC put a tasking memo to the staff on buried piping issues across the board. License renewal is one piece of that, to look at the GALL sufficiency, which we are in the process of updating. But other aspects are just, even under normal Part 50 and inspection processes, how much are we looking at buried piping?

So I think all of those things combined.

CHAIRMAN BONACA: Yes. One of the issues, I mean one of the concerns we have seen from previous applicants was that, when you go and you just dig to expose a piece of pipe, you are likely to damage the wrapping. So that has been always a concern with not expanding excessively the number of samples that you are going to dig. I guess they will have a plan.

MR. HOLIAN: I understand.

MEMBER MAYNARD: I would like to go back and make sure Said is going to get what you need there on the --

VICE CHAIRMAN ABDEL-KHALIK: I am just wondering if the staff has reviewed this calculation. Have you had the opportunity to review the applicant's calculation with regard to the containment penetration cooling system, the conduction calculation that shows a time of 58 days for the concrete surface to reach 300 degrees?

MS. GREEN: We did not request that they provide the actual calculation to us for review. We reviewed information like summary information from that calculation, statements that they had made. But I could have one of the gentlemen from the staff answer as to why they think that it is acceptable.

This is Rich Morante. He is a contractor from Brookhaven National Lab. He participated in the audits and reviewed several onsite documentations.

MR. MORANTE: As Kim said, my name is Rich Morante. I work for Brookhaven National Laboratory, and I have supported the staff in the review of structural issues for the IP2/3 application review.

The issue of the 300 degrees, we did not review the calculation specifically because, after gaining additional information from the applicant, we concluded that the penetrations have not been at elevated temperatures for any extended period of time during the 35 years of operation. So we did not base our conclusion --

VICE CHAIRMAN ABDEL-KHALIK: That is not the question. You know, the applicant presented --

MR. MORANTE: No. No, we did not. We did not review the calculation because the conclusion we drew that there's not an issue was not based on that calculation.

VICE CHAIRMAN ABDEL-KHALIK: It is an issue of credibility.

MR. MORANTE: I cannot answer that question.

MR. HOLIAN: If ACRS requests it, we can go back and look at that calculation. That can be done. I think what you heard from the staff is it was not necessary for our conclusion.

The credibility issue, you know, I mean we can separately talk about that. I think that is a stronger word for, do you need to review every calculation? We can discuss that in more detail.

We also rely, as you heard, on inspection reports or inspections, even subsequent to license renewal, that we will go back and sample aspects of these reviews.

So there is an interface there that doesn't get talked about, which is aspects from these open items, in particular, and commitments that are made, these 40-some commitments that are made, we highlight to the region for them to go out and review for how well are they implementing them. So there is further opportunity under the normal reactor process, once the license is issued.

So that conversation takes place. We interface with the regional folks on a regular, routine aspect on things for them to continue to look at. That could be a sample that we will choose.

MEMBER MAYNARD: I think we have to ask ourselves how important the calculation is to us, though. Personally, I put more into the inspection activities, what are they doing, what indications do they have to be able to identify if there is a point in time to correct it before it creates a problem.

The calculation, I'm not sure how important that is relative to that. I do believe that, from the geometry of the thing, there is time before you are going to be exceeding any temperatures for long enough to cause damage. So the real question to me is, are there inspection actions or operator rounds, the indications that they have, are those sufficient to identify that they've got blockage before it creates a problem?

MEMBER STETKAR: Yes, I agree. I think that I heard from Entergy that the operators are taking the appropriate measurements. I hope that is the case. I mean that is a staff inspection issue and things like that.

Just simply verifying that the fan is running and it isn't vibrating isn't sufficient to say that you are actually cooling that penetration. You need either differential pressure across the penetration or inlet and outlet temperatures, or something like that.

If, indeed, that type of information is being taken once a shift or once a day, that provides quite a bit of confidence that, indeed, they detect any type of fouling or blockage.

If that isn't being taken, then there is a question of whether the normal inspections are adequate to detect it.

MEMBER MAYNARD: Yes, I would like to go back over the geometry just one more time, make sure I understand the gap between the insulation and the concrete wall. From the dimensions that were given, that is a pretty good-sized gap, which is good. I mean, if it was a half-inch or a 1-inch gap, that is easier to plug than something that is quite a bit thicker.

Did you write that down or did somebody from Entergy? What was the gap between the --

MR. ORLANDO: This is Tom Orlando again.

The point we were trying to make was we have inspections that we do on a daily basis. We were trying to show that, had we taken no actions at all, there's a long period of time before the concrete would approach its design temperature of 300 degrees.

So we feel we have enough monitoring to show that the system is functioning, is proper. We have temperature readings. That just supports the fact that, if we are taking readings on a daily basis, that is a much shorter time period than had we taken no actions at all and have to heat up the whole 4.5-foot thick pieces of concrete.

Based on that conclusion, we feel that we have adequate monitoring to prevent it from getting up to the design temperature.

MEMBER MAYNARD: You gave some dimensions a while ago. Do you recall what the air gap was in there?

MR. ORLANDO: The air gap, I don't have that exact reading, but it is a few inches thick air gap with an insulated pipe. Then it goes to the penetration. Then we would have to heat up the 4.5-foot thicker concrete.

It was really just to try to highlight the fact that our inspections are much more frequent than --

VICE CHAIRMAN ABDEL-KHALIK: I thought the response earlier was that that time is the time required for the surface of the concrete to reach that temperature.

MR. ORLANDO: Right, the surface of the concrete, as the heat is being transferred into the concrete, it is also dissipating through that long, thick slab of concrete. So it is like a big heat sink, and that also has air on the outside.

So the point we were really trying to make is that our daily monitoring of the system operations and the periodicity and the operators bringing up the issues when they see it, that it is well before the time period that we would expect to the surface.

VICE CHAIRMAN ABDEL-KHALIK: I fully understand the argument.

MR. ORLANDO: Okay.

VICE CHAIRMAN ABDEL-KHALIK: And I fully understand the reason for presenting the calculation, in that you are trying to show that, if you don't do anything, you have plenty of time. But the question is whether or not that number is correct.

MR. ORLANDO: Okay. Well, we will gladly share that information with the staff and show how we came to that conclusion.

MEMBER STETKAR: Is the air gap completely filled with what is called the air-to-air heat exchanger? I mean, as I understand, the heat exchanger itself is a concentric pipe that has got, for lack of a better term, looks like a piece of corrugated cardboard with alternate channels in it.

Does that structure completely fill the air gap between the outside of the insulation and the inside of the concrete?

MR. ORLANDO: No, I don't believe it -- I think it is over on one end of the penetration. The air goes in and through that heat exchanger and then exits out the bottom. But I don't believe it fills up that whole air gap.

MEMBER STETKAR: Okay.

MEMBER BANERJEE: I think this can be resolved just by looking at the calculation. Let's table it and move on.

MR. MEYER: I would agree with you that inspection of some of the response actions they have would make sense, and they are counting on that. I don't have the authority to direct other inspectors, but I certainly will recommend that we take a look at that under the ongoing safety inspection.

MEMBER BROWN: Yes, I want to go back to the Checkworks thing one more time, beat this horse to death.

Of Checkworks is supposed to predict when you should do your next inspections, so that you do those inspections before you exceed minimum wall, and it has been in use since 1992 at the site, why didn't it predict that they were going to be below minimum wall and why didn't they inspect it before it got there?

MR. YODER: For these specific systems, I can't give you a good answer. I can tell you that parameters change. Parameters change as a result of power uprate. Some of the inputs to the code changed as part of an EPRI recommendation to make more realistic assumptions, rather than having overly conservative temperatures, flows, oxygen content. That is why we do UT.

MEMBER BROWN: Hold it. You're way down in the weeds.

What I am hearing is you are depending on a Checkworks program to tell you to go inspect the stuff before it exceeds, before you have a problem, and it didn't work.

Did I phrase that properly? Did I miss something?

MR. YODER: No, I understand what you're saying.

MEMBER BROWN: And so the answer back to me is: trust me, that now that we're going to feed this data in, the next time, after we have replaced -- I recognized it has been replaced, but it's not going to happen again. But it already happened once.

It is just a little bit fuzzy to me why I should just pony up to that answer. I am sorry I didn't think of that when you answered it. It is just that my brain wasn't integrating information.

MR. YODER: As Dr. Shack alluded to earlier, this is a growing model. The more data you put into this model, the better it is going to get.

MEMBER SHACK: But when did you have the power uprate? That certainly is a change in conditions.

MR. YODER: I think, and somebody can correct me if I am wrong, but I think we have had one or two cycles since the uprate.

MEMBER BROWN: So you are talking about three or four years, something like that?

MEMBER SHACK: One or two cycles.

MEMBER BROWN: What is a cycle? Two years, isn't it, something like that? So that shouldn't have had that -- why would just one or two cycles --

MEMBER MAYNARD: First of all, none of these programs are ever going to be perfect at predicting. They wouldn't be living programs if they were perfect, if you would never have any adjustment to make. So they are living.

MEMBER BROWN: Yes, but my issue, if you

know your model is limiting, then you ought to be doing something that allows you not to run into this condition.

I mean some of these minimal -- they were pretty severe. It was a third of what it was supposed to be, or something like that.

MEMBER ARMIJO: I think Checkworks tells you where to look primarily, and then, secondly, when to look. The when to look is based on a lot of empirical information, and it is limited. It is far from perfect, Charlie.

MEMBER SIEBER: The model is simple.

MEMBER ARMIJO: It's very simple, yes. It is an experience-based --

MEMBER MAYNARD: You have two identical plants, but their experience will be different over time, and you will end up with --

MEMBER BROWN: Holes in pipes aren't good things. I'm an electrical guy, but I don't like holes in my electrical stuff. Holes in pipes are worse. Mine open up and stop generally.

(Laughter.)

All right, I quit.

MEMBER MAYNARD: Do we have any other questions for the staff or for the applicant?

(No response.)

If not, I will turn it back over to you, Mr. Chairman, a few minutes early.

CHAIRMAN BONACA: Yes, and we are ahead of time. So we will take a break now and get back again at 11:15.

MEMBER MAYNARD: We didn't have any requests by the requirements there, but we do have a little bit of time. So we will allow you to go ahead.

MS. BRANCATO: I apologize. My name is Deborah Brancato. I'm from Riverkeeper.

I first just wanted to take a moment to thank the ACRS for accepting Riverkeeper's written comments. We believe we have raised some credible safety concerns, and we appreciate you taking the time to consider them and discuss those issues here today.

I would just like to briefly offer a comment in light of the discussions today.

First, in relation to metal fatigue, as discussed in greater detail in Riverkeeper's written comments, we continue to maintain that Entergy's commitment to refine its calculations and vague promises to address aging effects is not only insufficient to comply with applicable regulations, but also takes away meaningful review of the program by the public and the ACRS.

We, therefore, would request that the ACRS withhold final judgment on the sufficiency of the metal fatigue program until complete analyses are performed.

In regard to the flow-accelerated corrosion program, notwithstanding the information presented here today by the NRC staff, Riverkeeper maintains that the FAC program at Indian Point is fundamentally flawed because it is largely based on Checkworks and improperly benchmarked in an inaccurate computer program.

Lastly, in regard to the spent fuel pool leak issue, Riverkeeper continues to believe that sole reliance on a long-term groundwater monitoring program is not sufficient to address the leakage problem.

Even representations made here today demonstrate that the program is not a perfect system and would not be able to detect a leak under certain sensitivities.

Accordingly, and as discussed in greater detail in Riverkeeper's written submissions, it is imperative that Entergy determine unequivocally that the pools are physically sound and not leaking. To the contrary, Entergy has not, and will not, inspect approximately 40 percent of the Unit 2 pool liner and has no plans for enhanced inspections in the future.

Riverkeeper finds it is problematic, notwithstanding the, quote, "robust", long-term monitoring program.

We, thus, ask the ACRS to address these concerns.

In sum, Riverkeeper does not feel that the issues that we have raised to the ACRS have been adequately addressed by the information presented here today, and defer the ACRS to Riverkeeper's much more extensive written submissions.

Thank you again for your time and consideration.

MEMBER MAYNARD: Okay. Thank you for your comments.

CHAIRMAN BONACA: Any additional comments?

(No response.)

I don't see any. So, with that, we will take a break until 11:15.

(Whereupon, the foregoing matter went off the record at 10:47 a.m. and went back on the record at 11:15 a.m.)

CHAIRMAN BONACA: Let's get back into session.

Before we proceed with TMI-1, Entergy would like to make a couple of clarifications on the record regarding questions we have raised this morning.

So I will give the floor to Entergy.

MR. AZEVEDO: This is Nelson Azevedo again. I'm Supervisor of Programs at Indian Point.

There is some confusion in the discussion in the previous session as to how Checkworks was used. Checkworks is only one of several tools used to select FAC locations.

The specific location that we are talking about, the event chamber line was, in fact, not modeled in Checkworks. That was selected for inspection based on operating experience. So there is some question as to why didn't Checkworks identify this location. It was not modeled in Checkworks.

MR. McCAFFREY: This is Tom McCaffrey. I'm the Manager of Design Engineering.

There was some confusion on how we addressed the answer associated with the penetration cooling system, and specifically, dealing with the thousand hours.

The original calculation, which was a UENC calculation, there was a study done showing that the thousand hours was based upon one heat exchanger being out of service and still taking credit for the adjacent heat exchangers.

The example I will give you is, if there's two adjacent heat exchangers out, the time will drop down to 200 hours. So there is significant changes on the way this calc shows the impact of conduction. We did not do a good job explaining that, the way the analysis was set up.

MEMBER BROWN: What was the time with both of them out?

MR. McCAFFREY: Two hundred hours if the adjacent heat exchanger is out of service.

CHAIRMAN BONACA: Okay. Any further statements?

(No response.)

Any questions?

(No response.)

If there are none, thank you.

We can now turn to the TMI-1 LRA, and John Stetkar will take us through the presentation.

MEMBER STETKAR: Thank you, Mr. Chairman. I will make this brief, so we can get to the presentations.

We had a Subcommittee meeting on the TMI-1 license renewal on April 1st. At that time, we had a draft SER with no open items. So, at that time, there were little areas of concern.

We had some questions at the Subcommittee meeting, in particular, on the extent of plant operating experience that was considered as a basis for the applicant's programs, some questions about the containment liner, buried cables, and two or three other issues that I believe the applicant will address in their presentation this morning.

I think, with that, to just keep us on schedule, I will turn it over to Brian Holian.

MR. HOLIAN: Good. Thank you.

Just introductions, again: we will similarly follow the agenda that we had for Indian Point this morning. The applicant will go first, followed by the staff.

I will mention that Jay Robinson is the Senior PM. He will be doing the majority of the staff presentation. However, we also do have Michael Modes, again, a Senior Inspector from the Division of Reactor Safety in Region 1, here also, when that aspect comes.

Once again, we didn't have any open items. We had one confirmatory item related to dissolved oxygen that the staff had the information in hand and was still reviewing at the time of the Subcommittee meeting.

With that, I will turn it over to the Vice President, Mr. Mike Gallagher.

MR. GALLAGHER: Good morning. My name is Mike Gallagher, and I'm the Vice President of License Renewal for Exelon.

Before we get into today's presentation, I would like to introduce the presenters to you.

First, we have Dave Atherholt. Dave is our Regulatory Assurance Manager at Three Mile Island. Dave has over 25 years in nuclear power plant experience.

Next we have Al Fulvio. Al is our Corporate License Renewal Manager. Al has over 35 years' experience in nuclear power plants and over 10 years' experience in license renewal.

Next we have Pat Bennett. Pat is our Mechanical Engineering Design Manager, and Pat has over 25 years' experience at TMI also.

To my left here, I have Chris Wilson. Chris is our Project Licensing Lead, and Chris has over 25 years in nuclear power plant experience.

In addition to our technical staff, which is over here, we have Bill Noll with us today. Bill is our Site Vice President at TMI.

If we go to slide, I guess it's 2 there, slide 2 shows our agenda for the presentation.

So, as Mr. Stetkar noted, early in the presentation, we will present to you our followup on the Subcommittee's issue on operating experience. The Subcommittee had some questions relative to our use of the EPRI mechanical tools for operating experience, instead of using a more specific TMI operating experience in preparing the application.

We will present to you the details on this issue, but, in summary, we did credit the use of EPRI mechanical tools not only in the mechanical area, that is, not in the structural or the electrical areas, and only to identify aging effects for aging management reviews and not for the program effectiveness for the aging management programs.

Since the Subcommittee meeting on April 1st, we have conducted a plant-specific operating experience review for the period of time that we did credit the EPRI mechanical tools, and we identified no additional aging effects for that. So we concluded that our application was valid.

We will also present results of the summary of the other topics we discussed at the

Subcommittee meeting. So, overall, we believe we have developed a robust, high-quality license renewal application. We have developed an overall effective aging management program to ensure continued safe operation of TMI.

We appreciate this opportunity to present to you today and look forward to answering any questions you may have.

So now I will turn it over to Dave Atherholt, who will begin our presentation.

MR. ATHERHOLT: Good morning. I will be talking about the site description. Please go to slide No. 4. Thank you.

Three Mile Island Unit 1 is a Babcock & Wilcox pressurized water reactor. It is located on Three Mile Island, which is in the Susquehanna River.

The unit went into commercial operation in September 1974 and remained in operation until the TMI-2 accident in March of 1979. The unit stayed down, shut down, for six years, and then restarted in 1985.

We did undergo a power uprate of 1.3 percent to 2568, as indicated on the slide.

We did undergo a sale from GPU to the AmerGen Company in 1999. You can see on the slide the investment that was made in the plant from turbo-rotor replacements, main and aux transformer replacements, a new reactor vessel head, and, as you see later on this slide, we are going to replace steam generators in the 1R18 outage.

The unit then, subsequently, transferred license from AmerGen to Exelon in January of 2009.

As you can see lower on the slide, we have had two consecutive breaker runs, our breaker-to-breaker runs. We have high-capability factor in the unit, and we are currently in a third run of 659 days, on a way to a third breaker or breaker run. It indicates safe and reliable operation of the Three Mile Island Unit No. 1.

License currently is under expiration on April 19th, 2014.

At this point in time, I will turn it over to Al Fulvio.

MEMBER BANERJEE: You have a scheduled insulation of the new steam generators. How long would that take?

MR. ATHERHOLT: Yes, the business plan schedule for the replacement of the steam generators is a 66-day outage. Last scheduled revision was approximately 70 days.

MEMBER BANERJEE: Thank you.

MR. FULVIO: Good morning. My name is Al Fulvio. I will discuss a follow-up item from the ACRS Subcommittee meeting in April.

The issue is that NEI 95-10, which is the industry guidance for preparing license renewal applications, recommends a plant-specific operating experience review for aging effects requiring management.

In preparing our license renewal application for TMI, we credited the EPRI mechanical tools for a part of the time period for the mechanical systems operating experience review.

Slide No. 7. In preparing a license renewal application, there are two sections where operating experience reviews are performed.

One section is the aging management programs, which is shown as the left branch of this graphic AMPs. For each program, an operating experience review is performed to assess that program's effectiveness. The review consists of an industry OPEX review and a plant-specific OPEX review.

For the TMI application, this review was performed for all the aging management programs, per the recommendations of NEI 95-10. This part of the

OPEX review is, therefore, not the issue.

On the righthand side of that graphic is the other section of the LRA where operating experience reviews are performed for the aging management reviews for systems and structures. That is AMRs.

For each system and structure, an operating experience review is performed to determine if there are any aging effects discovered that have not been previously identified. The review consists of an industry OPEX review and a plant-specific OPEX review.

The issue relates to this section in the plant-specific OPEX review, which is colored green, for mechanical systems only.

Slide No. 8, here we have expanded the AMR branch of the OPEX review. There is the industry OPEX review, which consists of a five-year review of NRC and INPO communications and the GALL report. This review was performed for all the systems and structures, per the recommendations of NEI 95-10.

Now, looking at the plant-specific OPEX branch, we have expanded it to show that the reviews are performed by discipline, mechanical, electrical, and structural. The electrical systems and structures were reviewed, per the recommendations of NEI 95-10, and are not part of the issue.

The issue is that, for the mechanical systems only, the plant-specific OPEX review was performed for two years of operating experience, and the EPRI mechanical tools were credited for three years of experience, up to the latest revision date of the mechanical tools. Again, that is shown in green on the graphic.

Slide No. 9. In order to validate the review performed for the TMI license renewal application, we recently performed the plant-specific OPEX review for the mechanical systems for the three years, where the EPRI mechanical tools were credited. This review looked at over 5,000 plant-specific operating and maintenance items. We did not find any additional aging effects that were not previously identified.

Slide No. 10. In conclusion, the EPRI mechanical tools were originally credited for three years of operating experience for the plant-specific aging effects requiring management for mechanical systems.

To validate the original review, plant-specific review was performed for that three-year period, and no new aging effects were identified.

Therefore, the results of the operating experience review for the development of the TMI license renewal application were validated.

Are there any questions concerning this?

(No response.)

Okay. I would like to go, then, to slide 11 and discuss our GALL consistency and commitments.

So, for slide 12, we had a total of 38 aging management programs. Twenty-four of those were consistent with GALL; 14 had exceptions to GALL.

There were 43 total license renewal commitments, 38 of which were associated with those aging management programs.

In addition, we have committed to follow the PWR vessel internal program to install new steam generators prior to the PEO; to submit new pressure temperature limit curves to the NRC prior to exceeding 29 effective full power years, and prior to the PEO; to weld repair the reactor building liner prior to the PEO, and to continue our boral test coupon surveillance for the fuel storage racks throughout the period of the PEO.

Any questions in that regard?

(No response.)

Okay. I would like to turn the presentation over to Pat Bennett, who will talk about containment.

MR. BENNETT: Good morning. My name is Pat Bennett, and I'm the Mechanical Engineering Manager at TMI.

My topic is the reactor building liner and the corrosion issue we first identified in the 1990s with our ASME IWE program.

We monitored its condition through the IWE program and took corrective actions, when we discovered corrosion, by cleaning and recoating the affected liner areas. This presentation will describe how we are addressing the corrosion issue.

Next slide.

The issue is past borated water leakage and a degraded moisture barrier that resulted in corrosion behind and just above the moisture barrier, and we have fixed this.

The diagram to the left on your slide shows the bottom floor of the reactor building, where it nears the wall liner, and the area of interest is Detail A, as you can see on this slide at the left there. You move over to the right, and you see the detail. It is magnified to the right. You can see the carbon steel liner with the moisture barrier taking up the gap to the concrete floor slab.

The combination of areas of degraded moisture barrier with episodes of borated water leakage were the cause of liner coating degradation and the resulting corrosion.

MEMBER SHACK: How far does the cork liner extent?

MR. BENNETT: How far does the -- I'm sorry?

MEMBER SHACK: The cork liner, the cork.

MR. BENNETT: The cork? Oh, okay. The cork, it's a construction aid that comes up to, at various levels, about 4 inches with the moisture barrier; sometimes you see about 2 inches within the moisture barrier.

MEMBER SHACK: And it is underneath the whole thing or it just goes down a couple of feet?

MR. BENNETT: No, it is underneath. It is where the floor was poured up against the liner.

The next slide is a plan view of the areas where we found corrosion.

MEMBER RAY: Could we pursue that just a little bit further?

MR. BENNETT: Sure.

MEMBER RAY: Oftentimes, people feel that contact between the steel and the concrete is a good thing because it passivates the surface and avoids the corrosive environment. That would not be claimed for the cork liner, would it?

MR. BENNETT: That's correct. The cork is between the concrete and the liner.

MEMBER RAY: So, whatever the environment is on that side, it wouldn't be the same as it is on the other side, where I understand it is in contact with the concrete, or thought to be, anyway?

MR. BENNETT: Right. The outside wall of the reactor building butts up, the concrete butts up against the liner, that is correct.

MEMBER RAY: Yes. Thank you.

MR. BENNETT: Okay. Now this slide is a plan view of the lower level, the reactor building. We removed the moisture barrier 360 degrees around the reactor building, and we inspected above, at, and below the moisture barrier.

We found no corrosion below the moisture barrier. The worse corrosion that we did find was behind the moisture barrier, up against the wall, where the moisture barrier had separated from the liner.

Anywhere there was corrosion, we measured the liner wall thickness, and these are the areas you see on the diagram.

We evaluated the data to show that even the thinnest area was within design requirements. And on the next slide, I will talk about specific actions that we have taken to prevent reoccurrence --

MEMBER SHACK: How much of the cork did you dig out when you did that?

MR. BENNETT: When we did the inspection? We removed sections of cork. Some areas there wasn't cork in the gap 4 inches down, but we inspected down 8 inches, 4 to 8 inches down the gap.

MEMBER RAY: So the inspection gave you confidence that, if you had gone further down, you wouldn't have found corrosion? I am trying to understand that better. So, if you could elaborate, please?

MR. BENNETT: That is correct. I mean we did the visual inspection, and we removed the moisture barrier all the way around. So we did the visual inspection all the way around and went down 4 to 8 inches, looked in that area, and saw no corrosion whatsoever.

MEMBER SHACK: All the way around 4 to 8

inches?

MR. BENNETT: All the way around, yes.

MEMBER RAY: Do you have any explanation for that that occurs to you, as to why in elevation, I will call it, the corrosion would have been localized where you found it?

MR. BENNETT: Yes. What we found was that, when we looked in these areas of corrosion, we found that the moisture barrier hadn't come completely, you know, dried out completely, shrunk away from the liner.

The problem areas we found were where it separated somewhat from the liner, and that is where, if you had borated water or water leakage, it would stand in that gap between the moisture barrier and the liner and cause a corrosion.

So we didn't see --

MEMBER RAY: Did it migrate further down through the cork?

MR. BENNETT: Well, from what we saw, what we saw when we did our inspection and removed the moisture barrier, it hadn't come completely away from the wall. It had separated some from the wall, but hadn't completely been detached.

MEMBER BANERJEE: Was this a pitting

corrosion or what sort of corrosion was it?

MR. BENNETT: The corrosion that we found was a general surface corrosion. In some areas, we found, there are some smaller areas, and they point out these 15 areas where we had measurements that were below 90 percent nominal. It was generalized corrosion.

MEMBER BANERJEE: So it was just generalized sort of corrosion? There weren't pits or anything?

MR. GALLAGHER: That's correct. There was generalized corrosion. What Pat is referring to, we are trying to show you the thinnest areas that we identified.

MR. BENNETT: Right.

MEMBER RAY: We are trying to understand why it occurred where it did, and what caused it to be where it occurred.

MR. BENNETT: Right. Well, the issue was we had, like I said, there were periods, episodes of leakage, borated water leakage. One was due to a leaking seal plate, canal seal plate.

MEMBER RAY: That's the source of the water --

MR. BENNETT: Right.

MEMBER RAY: -- but is there something that we are not understanding that prevented the water from migrating further down?

MR. BENNETT: Yes.

MR. GALLAGHER: Yes, and I mean that's --

MEMBER RAY: The cork effectively prevented that, did it?

MR. GALLAGHER: Well, no. Basically, what Pat is saying is that the moisture barrier wasn't completely removed. It was there, but there were gaps in it between the moisture barrier and the wall that would hold up some borated water.

Part of the inspection plan was just to your point, was to verify where did the corrosion stop. So, as Pat said, I mean, the inspection plan did look at, okay, where did the corrosion stop, and then looked a little bit beyond that, and we verified that it was just in this band behind the moisture --

MEMBER RAY: Let me be clear. I am not questioning what you found. I'm just trying to understand the mechanism that was at work from what you found.

MR. GALLAGHER: Right. Okay.

MEMBER RAY: So I am not challenging it. I just wanted to understand it in more detail, so that we could draw any lessons from it that applied.

It still seems mystifying that you wouldn't have found any corrosion further down than just at the plane of the floor intersection with the liner.

MR. GALLAGHER: Right.

MEMBER RAY: That is what seems strange.

MR. GALLAGHER: Yes. Well, that was our visual inspection and 360 degrees around. Like I said, we found corrosion at the moisture barrier, and sometimes if you had a gap, if it had separated, you saw some corrosion there. But most of the corrosion was up the wall from the moisture barrier.

MEMBER RAY: Did you do any chemical tests -- just a second, Jack; I've got one more.

MEMBER SIEBER: Go ahead.

MEMBER RAY: You're quite aware, I'm sure, that we have this experience with wood creating an environment that is corrosive. The cork, apparently, didn't do that, is that right?

MR. GALLAGHER: No. No, the cork was dry. So we didn't see that.

MEMBER RAY: I'm done. Go ahead, Jack.

MEMBER SIEBER: Well, could you tell me the area and the depth of the area of greatest corrosion?

MR. BENNETT: The area, well, we had, as I said, and you see on the drawing up there, we had about 53 linear feet of general corrosion that we saw around the reactor building floor, which is about 13 to 14 percent of the area there. It was just a --

MR. GALLAGHER: Of the circumference.

MR. BENNETT: Of the circumference, that's correct.

MR. GALLAGHER: There was this 3-inch band behind and near the moisture barrier.

MR. BENNETT: Correct.

MEMBER SIEBER: But, in the aggregate, 50 feet of that?

MR. GALLAGHER: Fifty-three linear feet, which is about 12 percent of the circumference.

MEMBER SIEBER: And what is the depth?

MR. BENNETT: The depth you see up there is -- we showed the worst areas where we saw below 90 percent nominal.

MR. GALLAGHER: Right. So that is shown --

MEMBER SIEBER: What is the deepest one?

MR. BENNETT: The deepest one is 242 mils.

MR. GALLAGHER: Two hundred and forty-two mils.

MR. BENNETT: Nominal 375. That is correct.

VICE CHAIRMAN ABDEL-KHALIK: When you talk about the knuckle region, you are talking about much farther down?

MR. BENNETT: Yes. The knuckle region is where we --

VICE CHAIRMAN ABDEL-KHALIK: The mechanism for the reduction in thickness from a nominal three-quarters of an inch to 582 mils, is that the same mechanism?

MR. BENNETT: The same mechanism.

VICE CHAIRMAN ABDEL-KHALIK: So that means the water had penetrated all the way down to the bottom?

MR. BENNETT: Well, no. See, that area there is a lower level; it is an in-core chase room.

MR. GALLAGHER: Yes. So there is actually a concrete cutout. You know, there is a little room, so you can access down to that point. So that point is more like the floor elevation. So it is lower in that area, so you can get to the knuckle.

VICE CHAIRMAN ABDEL-KHALIK: Okay.

MEMBER BROWN: The moisture barrier, I am just trying to understand. You said it didn't separate. You mean vertically along the wall, it had not gotten clear down to the cork?

MR. BENNETT: That is correct.

MEMBER BROWN: That is why you didn't see any moisture under the cork? I was trying to address your point about why it didn't get under the cork.

So it did not clear around the circumference? It only went partway down that half-inch-thick barrier that separated at the top but not at the bottom?

MR. BENNETT: That is correct.

MEMBER BROWN: So that is why the moisture didn't get into the cork?

MR. BENNETT: That's correct.

MEMBER BROWN: At least that is what I am understanding.

MEMBER RAY: That is a good clarification, Charlie. I did pick up, though, on the explanation -- and I think it was the staff writeup -- saying that the corrosion had been caused by a failure of the moisture barrier. So I am trying to understand that, okay? That is the problem I am having.

MR. BENNETT: The failure of the moisture barrier is that it became detached, and that we had

had borated -- it is borated water mixing with this problem with the moisture barrier.

MEMBER RAY: When it became detached, did it also pull away the coating on the liner? Is that --

MR. BENNETT: Well, we saw areas where the coating had bubbled out and the coating had failed there. That is where we had the general corrosion.

MEMBER RAY: So, my understanding, to get back to Charlie's point, my understanding that the failure of the moisture barrier had allowed water to go much lower is incorrect? The failure of the moisture barrier had simply exposed the liner at that point?

MR. BENNETT: That's correct.

MR. GALLAGHER: And as Pat said, we have replaced 100 percent of the moisture barrier.

MEMBER RAY: Yes, I got it. This is very important for us to understand as best we can, so we don't take away the wrong impression as to what the effect of the moisture barrier failure was in what happened.

MR. BENNETT: Okay. All right.

MEMBER RAY: So thank you for helping us understand that.

MEMBER BANERJEE: When you say 242 mils, is that the current thickness?

MR. BENNETT: That is correct, in that one spot.

MEMBER BANERJEE: All right. Thanks.

MR. BENNETT: Okay. So, in summary, we identified corrosion in the 1990s and monitored and inspected the liner with our IWE program. The cause of the reactor building liner corrosion was borated water leakage and a degraded moisture barrier, and we have fixed this.

Specifically, the mitigation steps that we took are we corrected the leaks, established the boric acid or corrosion control program. We inspected the entire moisture barrier liner perimeter in 2007. We measured the wall thickness of the corroded liner areas in 2007 and ensured the existing liner meets design requirements. We removed the old moisture barrier; cleaned/recoated the corroded liner; installed a new moisture barrier in 2007, and we inspect 100 percent of the moisture barrier every refueling outage, starting in 2009.

Our liner repair plan is to weld repair any thinned area to establish all areas greater than 90 percent nominal thickness prior to the period of extended operations. That is currently scheduled with our fall refueling outage this fall. That will be along with the plant's integrated leak rate test.

MEMBER SIEBER: Is that going to be a manual weld repair?

MR. BENNETT: Yes, that is correct, manual weld repair.

MEMBER SIEBER: You are going to have to remove part of the floor to get to it?

MR. BENNETT: That is correct.

MEMBER SIEBER: So this is not going to be a simple --

MR. BENNETT: No, it is not.

MEMBER SIEBER: What are your inspection plans following the weld repair?

MR. BENNETT: I will turn that over to our --

MEMBER SIEBER: Slag inclusions, difficulties with the manual welding, and all that, how are you going to make sure that it is okay?

MR. BENNETT: I will turn that over to Gene Navratil.

MR. NAVRATIL: Gene Navratil, Exelon.

Our plans are, essentially, to start off with the excavation of the concrete. Upon inspection, we will perform surface prep, then do a magnetic particle examination and remaining wall thickness recording of that area before we start welding.

Then we will perform the welding with qualified welders that will have some mockup training on this type of access.

Then we will perform magnetic particle examination after each layer. We expect two to three layers for most of the repairs. So we will perform a magnetic particle examination after each layer is applied.

Then, at the end, we will prep, have a final surface prep, perform final MT examination, UT examination for remaining wall thickness, and visual examinations prior to coating and after coating.

MEMBER SIEBER: A couple of questions. Surface prep is by grinding?

MR. NAVRATIL: Yes, that will be manual grinding, correct.

MEMBER SIEBER: That will be manual, right?

MR. NAVRATIL: Yes, that is correct.

MEMBER SIEBER: Then you do passes on that, grind them down, continue to do that until you get to about 90 percent? Then you surface prep, and are you going to use UT to determine thickness? And if you are, your inspection plan will also identify slag inclusions and other imperfections in the welding, I presume?

MR. NAVRATIL: Yes, the UT examination after the completion of the welding will be just to determine the remaining wall thickness.

The magnetic particle examination is the examination that is used for weld flaw detection. So that would detect any --

MEMBER SIEBER: Slag?

MR. NAVRATIL: Yes, it would detect unacceptable indications in that weld. That is in accordance with the ASME Code requirements.

MEMBER SIEBER: Slag particle testing on a vertical surface, I presume these are partially vertical, inclined. You are going to need a pretty big trench --

MR. NAVRATIL: Yes.

MEMBER SIEBER: -- in order to get to it?

MR. NAVRATIL: Yes.

MEMBER SIEBER: And to be able to see it? You can't see it straight on; you have to look at it at an angle. Are you going to do the special qualification to assure that the mag particle will work in that configuration?

MR. NAVRATIL: Well, the procedural requirements will be that you still have to maintain the distances, like the contact poles have to be "X" inches beyond the area of interest.

With the removal process we have, we will have a straight-vision access to those welds. It will be very straightforward.

We do not at this time have a specific qualification plan for those NDE inspectors.

MEMBER SIEBER: Now, after you are done, you are going to backfill the areas that you excavated. And what will the backfill be, concrete, cork?

MR. BENNETT: Concrete.

MEMBER SIEBER: Moisture barrier. Are you going to concrete right up to the liner?

MR. BENNETT: They will concrete with a gap in moisture barrier, just the same as we have right now.

MEMBER SIEBER: Including the cork?

MR. BENNETT: Yes. It is like-for-like replacement.

MEMBER SIEBER: I will think about that for a minute.

MR. BENNETT: Okay.

MEMBER SIEBER: Thank you.

MR. BENNETT: Okay. The next presenter is Dave Atherholt.

MR. ATHERHOLT: Good morning again. I am Dave Atherholt, the Site Reg Assurance Manager. I will be talking about medium voltage cables.

Slide No. 18, please.

Although we have had no failures of the medium voltage cables at TMI, we have had an issue that we have identified during periodic cable vault inspection. We have identified some vaults that did have repeat occurrences of rainwater accumulation and cable submergence.

At TMI, there is a total of 37 cable vaults. However, there's eight cable vaults that are in the scope for the license renewal program.

Again, as I indicated earlier, there have been no failures of medium voltage cables at TMI.

Let's move on to slide 19. If you will look at this slide, on the left side of this slide you will see a cross-sectional view.

VICE CHAIRMAN ABDEL-KHALIK: Excuse me. How do you define failure?

MR. ATHERHOLT: Pardon me?

VICE CHAIRMAN ABDEL-KHALIK: How do you define failure in the previous slide?

MR. ATHERHOLT: We define failure by the cable preventing the intended equipment near the switch gear buses or those pumps from performing its intended function. We have never identified any of those or have had any failures under testing of the cables that we have tested.

VICE CHAIRMAN ABDEL-KHALIK: Okay. So that doesn't include possible degradation of the cables? You have no idea? Do you have a test that would tell you the current state of the cables?

MR. ATHERHOLT: The test that we currently do is Megger testing. I will ask --

MR. GALLAGHER: So we do Megger testing on these cables, and that is basically all the testing that is available right now. That is not a predictive test per se. We are working with the industry and EPRI on what other testing methods can be done, and we employ those once they become available. But that is the testing to date that has been done.

MR. ATHERHOLT: Okay, I will continue on.

The cross-sectional view of the manhole is indicated to your left. This is a typical view of a cable vault. The depths vary of the cable vaults that are in scope for license renewal, anywhere from 8- to 15-feet deep from the above-sea level elevation of 299 to 305 foot. The bottom of the cable vaults are located 5 to 15 feet above the water table on Three Mile Island.

The cable vaults are compartmentalized in that they could have two or three compartments within the existing vault itself. The vaults are designed to have French drains for rainwater removal. Internal to the cable vaults, the cables do, in fact, transition from various elevations as a result of the terrain and specific cable routings.

MEMBER SIEBER: Are there splices?

MR. ATHERHOLT: These medium voltage cables have no splices involved.

MEMBER SIEBER: The cable vault, there are no splices in there?

MR. ATHERHOLT: That is correct.

MEMBER SIEBER: The lid is a regular manhole like you would find in the city street?

MR. ATHERHOLT: The lid is manufactured by, I believe, Neenah Foundry. It is a bolted and gasketed lid. It is somewhat different than what you would find in a street. It is actually a square lid with a hinge on the back side of it. It has a neoprene gasket internal to it. It gets sealed, and it gets bolted down. So a little different than a sewer-type manhole.

MEMBER SIEBER: So it is actually machined so that it is not supposed to leak?

MR. ATHERHOLT: It is designed not to leak, based upon the gasket being installed in the manhole.

Okay. Moving on to slide No. 20, the actions that we put in place to prevent accumulation of rainwater in these cable vaults are listed. We have implemented a semi-annual inspection. We have completed all the inspections on those vaults since the previous ACRS Subcommittee meeting.

We have implemented a cable vault improvement initiative. As it was identified, these particular manholes do have gaskets. We have found that the gaskets over time were, in fact, degraded. We replaced all the lid gaskets as necessary that were degraded. And in fact, we found some degradation of the manhole covers. I will use the "manhole" term. Those covers were, in fact, replaced.

As necessary, we improved grading from around that area to prevent the runoff into the vaults, and we have restored French drain systems as they existed in the vaults.

We are in the process of adjusting frequency of inspections, based upon the inspection results accumulated.

In addition, as Mike had said earlier and we talked about, we are looking at, what is the appropriate cable test to perform? We intend to test these cables prior to the period of extended operation.

Our conclusion is that the appropriate controls that we put in place through our corrective action program have appropriately managed the rainwater intrusion, and we will meet our goal of preventing rainwater intrusion such that these cables will become submerged.

Any questions?

MEMBER BROWN: Yes. What voltage do these medium voltage cables operate?

MR. ATHERHOLT: These cables are 41/60-volt cables.

MEMBER BROWN: At what voltage do you do your Megger checks? I presume it is 5,000-volt Megger, is that --

MR. GALLAGHER: Randy, do you want to answer that question?

MEMBER BROWN: It was just a yes or a no, 5,000 or not. Something lower or higher?

MS. SPAMER: Deb Spamer, Exelon.

Not only are the cables tested at two times the --

MEMBER BROWN: You Megger at two times the operating voltage? Dielectric shrinks testing, I understand that one, but Meggering is normally done something slightly different. I would be surprised if you did dielectric shrinks testing. That is a destructive test.

MR. GALLAGHER: We have the tests here, and we will look that number up.

MEMBER BROWN: Yes, I was just curious; that's all. It is not a make-or-break question. I just wanted to know what you do.

MEMBER STETKAR: We can do that, and we will see if we can keep on schedule here.

MEMBER BROWN: That's fine. Yes, we have to keep going.

MEMBER STETKAR: Mike, did you have a question?

MEMBER RYAN: In the conclusion, it says you will keep the medium voltage cables dry or infrequently submerged. What does that mean exactly?

MR. GALLAGHER: Yes, what we are trying to -- as you all know, this is an industry issue -- what we are trying to show here is we think we understand the issue, and we have programs that we are putting in place, and we have put in place so far, to manage this.

So we know it is not a groundwater issue. When we get water in these cable vaults, it is rainwater. We know that we can prevent the rainwater from coming in by maintaining the manholes and the gaskets, and we are doing that.

We also know that we are above the groundwater table, and we have French drains in these manholes. We need to maintain those, and we are doing that.

So we think we can be successful in keeping the cable vaults dry or infrequently submerged, you know, when you do have episodic rainwater events.

So that is what we are trying to convey.

MEMBER RYAN: And I may be picking on a detail point, but the caisson, which is the actual manhole, you know, the caisson itself, is that sealed on the outside, so that rain can't get down the side of that concrete? It will infiltrate from above, I guess is my point, and it will seek the French rain from the outside.

MR. GALLAGHER: Yes. I mean they are enclosed vaults, but I mean there are penetrations --

MEMBER RYAN: Well, they are not. I mean, are they enclosed on the bottom? They have a French drain which communicates somewhere.

MR. GALLAGHER: Yes, the bottom, there is a bottom.

MR. ATHERHOLT: The question, as I understand it, can you have communication from groundwater back through the French drain? The answer is yes.

MEMBER RYAN: Well, yes. I mean that is one, but, also, for infiltrating water from the top down.

MR. ATHERHOLT: The structure itself is a sealed structure. When we do inspections of that structure, we do note whether or not there's any cracks within the structure itself.

MEMBER RYAN: Yes, I know, but where is the French drain? Does that communicate outside to the bottom?

MR. ATHERHOLT: Yes.

MR. GALLAGHER: Yes, it drains the

bottom --

MR. ATHERHOLT: Correct.

MR. GALLAGHER: -- to a stone bed.

MEMBER RYAN: Okay. So there is a pathway back in if the rain seeks its way back in?

MR. GALLAGHER: It could. It could, but we are saying we are above the groundwater level.

MEMBER RYAN: It is not the groundwater I am talking about. Rainwater hits the surface outside the box and on the box. So that can run down the outside wall and hit the French drain and accumulate on the bottom.

MR. GALLAGHER: It could and then drain out.

MEMBER RYAN: So you haven't really guaranteed that you have prevented the cable from getting wet by putting the manhole cover on the top?

MR. GALLAGHER: Right. What we are saying is we are preventing the major source, and then, also, that we will maintain the French drains, so that we can keep --

MEMBER RYAN: So, hopefully, the drainage is out?

MR. GALLAGHER: Yes, we can keep it drained, yes.

MEMBER RYAN: And not back in?

MR. GALLAGHER: And that's the intent.

MEMBER SIEBER: Now TMI is built on an island in the middle of the Susquehanna River. Where is the water table normally? The water table goes up and down, but where is it normally with respect to the bottom of the manhole? And how high is the island surface above the river level?

MR. GALLAGHER: We will go to this slide and, Dave, you can give the numbers.

MR. ATHERHOLT: Yes, I can speak.

If you look at the top of the manhole, the top of that manhole is typically anywhere from 299 to 305 foot above sea level. The groundwater level on Three Mile Island is normally 281 foot.

And if you look at the depth -- and that is how we derive the --

MR. GALLAGHER: The river level, Dave, for --

MR. ATHERHOLT: The river level is a nominal level of 277 foot. So, if you look at that, that is how we derive the margin that we have from the bottom of the vaults to the groundwater elevation. That is how we concluded that it was rainwater, because of that margin from those particular elevations.

MEMBER SIEBER: Thank you.

MR. ATHERHOLT: Any particular questions?

(No response.)

Okay, at this point in time, I will turn it over to Al Fulvio.

MR. FULVIO: Yes, this is Al Fulvio again. I wanted to review some current industry issues with you.

On slide 22, for the station blackout, our boundary for the SBO recovery path does include switch yard circuit breakers.

For the boral issue, we will continue the boral coupon surveillance program throughout the period of extended operation.

And for fatigue, our environmentally-assisted fatigue has been satisfactorily evaluated. We did not use any simplified analysis methods in those calculations.

Any questions?

MEMBER STETKAR: You had time to look at the procedure over there. Do we have an answer?

MR. GALLAGHER: Yes, Mr. Brown, we do have some information if you want us to.

MEMBER BROWN: Is it just a number?

MR. GALLAGHER: Yes.

MEMBER BROWN: It shouldn't be long. I don't want to hold up the schedule here.

MR. GALLAGHER: It's a couple of tests. That is why it is a little bit more.

MEMBER BROWN: Oh, okay.

MR. EZZO: Randy Ezzo, Exelon.

Our procedure says we need to apply between 9,000 and 11,000 volts for our Baker box testing.

MEMBER BROWN: For what? I didn't hear the last part.

MR. EZZO: For the Baker box testing.

MEMBER BROWN: All right.

MR. EZZO: We test the cable and the motor.

MEMBER BROWN: Okay. Thank you. That works.

MEMBER STETKAR: Any other questions, Committee members?

(No response.)

If not, thank you very much for a very good presentation. I think you have clarified everything that we had questions on.

I will turn it over to the staff, which is rapidly disappearing.

(Laughter.)

MR. HOLIAN: This is Brian Holian, Director of License Renewal.

As the staff gets settled, I will just complete introductions:

Jay Robinson, the Senior Project Manager for License Renewal, will be doing the presentation, as I mentioned.

Mike Modes is here from the Region. So there weren't any outstanding questions, but he is here to answer any other inspection questions we might have from the Subcommittee time.

I also wanted to highlight Dave Pelton, who is the Branch Chief for Three Mile Island and other plants.

One other introduction I failed at the Indian Point time, but I wanted to highlight our two Environmental Project Managers.

One in the audience over here is Sara Lopas, the Environmental Project Manager for Three Mile Island. She has just received a promotion over to the New Reactor Environmental Group. So we are sorry to see her go.

The Subcommittee heard some comments from an environmental stakeholder there, and Sara has been involved in the DSEIS and the final SEIS for Three Mile Island, and responding to a lot of those issues. So I wanted to recognize her.

And Drew Styvenburg was the Environmental PM who was here for the Indian Point session earlier this morning.

With that, I will turn it over to Jay Robinson.

MR. ROBINSON: Thank you, Brian.

Good morning, Mr. Chairman and Committee members. My name is Jay Robinson. I will be presenting the staff's review of the license renewal application for Three Mile Island.

First, I would like to just do a brief introduction of what we will be looking at today. First, I will do a brief review of the Subcommittee meeting held back in April.

Then we will talk about the license renewal inspections and the operating experience review, followed by Sections 2, 3, and 4 of the application. Then we will have a brief conclusion.

So, looking at the review, the application was submitted in January of 2008. The staff conducted the scoping and screening audit, an AMP audit, and regional inspection. It is noteworthy that were additional components brought into scope as a result of those audits.

We did issue 123 requests for additional information. The applicant has 43 commitments in the application. The SER with open items was issued in March of 2009. There were no open items in that SER. There was one confirmatory item, and that concerned dissolved oxygen. I will talk about that later in the presentation.

Looking at the license renewal inspection, the operating experience review, the applicant, as they previously discussed, they did credit the EPRI mechanical tools in the mechanical system operating experience review for aging effects requiring management, which was different from the approach described in NEI 95-10.

The applicant subsequently conducted the plant-specific operating experience review for the period the EPRI tools were previously credited, and there were no new aging effects identified.

Subsequently, the regional staff performed a supplemental inspection on July 7th and confirmed the applicant's review.

There was an additional inspection report issued after that. I think we did forward you a copy of that. Being the fact that we did issue the SER before that inspection, we will update the SER to address that supplemental inspection.

The inspection conclusions concluded that the scoping of non-safety SSCs and aging management programs are acceptable and that the inspection results support a conclusion of reasonable assurance that aging effects will be managed and the intended functions will be maintained.

MEMBER MAYNARD: Okay. I understand what was done for TMI. Basically, as I recall, based on our Subcommittee questions, it appears that they went back and they did their operating experience review to confirm that use of the EPRI was all fine.

What about future plans? My question is more for the staff. Is what they did originally, is that an acceptable method or is the expectation that they really use in-house operating experience in the future?

MR. ROBINSON: The expectation is that they use the in-house operating experience, but if they use the mechanical tools, that it has to meet our guidelines in the Standard Review Plan.

MEMBER MAYNARD: I am not sure what that

means.

MEMBER STETKAR: What does that mean in practice?

MEMBER MAYNARD: It is a simple question as to whether, can they use that mechanical tool or would they have to do an in-house operating experience review?

Again, for TMI, this has basically been taken care of. I am talking about more for the future plants that come in. If somebody else comes in and did the same thing that TMI did originally, what is the staff's expectation here?

MR. GALLAGHER: I know you are asking the staff, but --

MEMBER MAYNARD: I am asking the staff, yes.

MR. GALLAGHER: I can just tell you what we are going to be doing at Exelon. The EPRI mechanical tools, there's a lot of good information. It is a good thing to start with, but we think a plant-specific review adds value. We do it anyway in regards to the aging management program. So we have changed our processes just to be integral, and then we can do them both at the same time and have all the information in there.

So this will be a non-issue in the future applications that we have.

MEMBER MAYNARD: For Exelon?

MR. GALLAGHER: Yes.

MR. PELTON: This is Dave Pelton.

Anytime a licensee would choose to follow an EPRI mechanical tool or any other tool that is provided, it is incumbent on them to make sure that they also justify the use of that tool, and not just expect a carte blanche tacit acceptance of the use of that tool without some further analysis or review.

So, anytime a licensee would propose to use or to deviate from the guidelines in NEI 95-10, I would expect or we would expect that they would also accompany that with some kind of a justification for doing so. Then we would have to evaluate that at that time.

So, moving forward, in a perfect world, they would do what you just heard where they would --

MEMBER MAYNARD: I'll stop because it doesn't really apply to TMI. It sounds like we may face this in the future with other plants.

MR. HOLIAN: Well, yes, this is Brian Holian, Director of License Renewal.

It is something the staff is being more

focused on, too. We have seen some differences in the way different applicants do it, Exelon, one way, Entergy, another way, on their aging management review operating experience. Some will even promise to do it when we put the aging management review in place, and the staff is pushing them.

I don't think our Standard Review Plan is that consistent on that. It is an area of heightened interest, and we are trying to ensure consistency. We have brought it up at NEI meetings, and we will continue to focus on this.

MEMBER MAYNARD: Go ahead.

MR. ROBINSON: Moving on to Section 2 of the application, structures and components subject to aging management review, Section 2 included the scoping and screening methodology, plant-level scoping results, and then it also included mechanical systems, structures, electrical system commodity groups.

Then, in conclusion, Section 2.3, mechanical systems, the staff identified nine systems that required the applicant to revise the application and add additional components into scope.

An example of the component types submitted include a fuel tank for the standby diesel engine for the emergency diesel generator, air start system, air compressor; lube oil lines, and intake bar racks. And these were subsequently added to scope and subject to AMR.

Section 2.4 on structures, the staff identified one component that required the applicant to revise their application and add the component into scope. This was the structural steel platform associated with the dike and flow control system.

Our conclusion for scoping and screening, based on the staff's review, the onsite audit, based on its review of the LRA, the onsite audit results, and additional information submitted as a result of the RAIs, the staff concluded that the applicant's scoping and screening methodology meets the requirements of 10 CFR 54.4 and 54.21(a)(1), and that the applicant adequately identified those SSCs within the scope of license renewal, in accordance with 10 CFR 54.4(a), and adequately identified those SCs subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

Moving on to Section 3, which is aging management programs, that included reactor coolant system, engineered safety features, the auxiliary systems, steam and power conversion system, containment structures, and component supports, and the electrical commodity groups.

The aging management programs, there were 38 AMPs. Seven were new. Thirty-one were existing. Twenty-one were consistent with GALL. Eleven had exceptions, and six had both enhancements and exceptions.

In regard to groundwater, groundwater is considered non-aggressive for steel embedded in concrete. The applicant is doing sampling every five years, will do sampling every five years, during the period of extended operation.

In regard to the reactor building liner, as previously discussed by the applicant, there was corrosion due to moisture intrusion through the moisture barrier. The current function of the liner is maintained through an engineering evaluation, and the applicant committed to restore the liner to its nominal plate thickness by weld repair prior to the period of extended operation.

MEMBER RAY: You understand the statement "intrusion through the moisture barrier" appears now to be ambiguous, based on what the applicant said? So it could mean beyond and beneath; whereas, as we understand it from the applicant, it did not mean beyond and beneath. It only meant that the moisture barrier was an area in which its failure had allowed corrosion to occur at that level, but not beyond it. And it is the beyond part that I, at least, was interested in.

So that wording is just not precise, if you guys agree that that was the condition experienced.

MR. HOLIAN: Yes, I understand.

MEMBER RAY: There was moisture beyond the barrier, but then the question of, well, why wasn't there corrosion beyond the barrier has to be answered, I would think.

MR. HOLIAN: Yes. This is Brian Holian.

We agree with you. I think even in the previous statement of the failure of the barrier, that was probably shorthand by the staff. It was meant, we recognize it as the applicant has stated it. It was separation from the wall and then corrosion behind the barrier.

MEMBER RAY: Thank you.

MEMBER BROWN: But not complete separation.

MEMBER RAY: Yes, this seems like it is picking at too much detail, but, in fact, it is important because we are trying to understand what we are seeing.

MR. ROBINSON: Okay, can we move on?

Moving on to the inaccessible medium voltage cables, there were some inaccessible medium voltage cables in some manholes that experienced water submergence for more than a few days. The staff found the cables submerged underwater in two manholes during our AMP audit.

As a result of the review, the applicant will adjust the frequency of inspections based on the inspection results. As we all know, water in the manholes is also a generic current operating plan issue that is being addressed in accordance with the requirements of 10 CFR Part 50.

In regard to reduction of neutron-absorbing capacity, this is being handled through the Water Chemistry Program and the boral surveillance program. The applicant has committed to continue the boral test coupon surveillance through the period of extended operation.

Based on its review of the LRA and additional information submitted as a result of the request for additional information, the staff concluded that aging effects will be managed so that the intended functions will be maintained consistent with the current licensing basis for the period of extended operation.

MEMBER BROWN: I have a question relative to the groundwater. I mean I am addressing your comment earlier, Mike.

If you found water in the manholes, that means, whenever it rained, however the groundwater leaked in, it doesn't sound like it left. It sounds like the French drains didn't work, which leads you to some conclusions. I'm not exactly sure what, but it is a little bit different than the story we got during the licensee presentation relative to how much was in there. I guess I didn't remember the two manholes had had water in them.

I am not saying this is a critical, damning-type thing. It is just that it seems like something didn't work right, if the water did not drain out.

MR. GALLAGHER: No, you are correct, Mr. Brown. The French drains in those two particular manholes weren't draining correctly. So our program now, as we said, is fix the gaskets, keep the French drains clear, and that type of thing. So we have this restored the way it ought to work, and then they should remain drained. But those particular drains were not fully functioning.

MEMBER BROWN: Okay. I will understand at least what went on. Thank you.

MEMBER RYAN: You say adjust the frequency. Where are you on making that decision? I recognize that it is an ongoing question, but like annually, semi-annually, every five years?

MR. GALLAGHER: Randy, do you have it?

MR. EZZO: Randy Ezzo, Exelon.

Right now, we are still at six months. I think what we talked about doing was, after remediation is fully completed, and then adjusting the frequency based on how much water we see accumulating in these vaults.

MEMBER RYAN: You're going to stick with six months and maybe go shorter or longer based on what you see?

MR. EZZO: That's correct.

MEMBER RYAN: But do you think it has any merit to look more frequently, particularly during the rainy season, to see what happens when the rain is coming down?

MR. EZZO: If we are seeing water accumulating in there, we would do that.

MEMBER RYAN: I would suggest that it is

critical what month you actually look.

(Laughter.)

Again, I don't think this is a gigantic issue, but it really depends on what time of the year you look, like after a snow melt. You know, that would be like maybe April or May or maybe April. Those kind of times are when you -- I would try to find the most optimum time when water would be there, and then make a decision after that.

MR. GALLAGHER: Yes, I think what you are saying is April showers bring May flowers.

MEMBER RYAN: Actually, it's all that snow from December to February.

MR. GALLAGHER: Yes, so we should take a look during those timeframes. So we will factor that in. Thanks.

MEMBER BROWN: There is one other point. I mean, do you know what plugged those French drains in those two? I mean, was it just dirt that backed up in it or chipmunks, birds' nests?

MR. EZZO: Randy Ezzo.

We didn't find any chipmunks.

(Laughter.)

What we found was, it was kind of surprising. The drains were not in accordance with the drawings. They were filled with either concrete.

(Laughter.)

Some of the drains were functioning. Those we did unclog and we tested them, and they work. Others we have more work to do to correct those.

MEMBER BROWN: I'm glad I asked the question now.

(Laughter.)

MR. HOLIAN: Brian Holian, License Renewal.

Just to add, it is both a Part 50 and Part 54 question. I just add that the regions are picking up their inspections of this aspect. Enforcement, where appropriate, for where they are not doing appropriate corrective actions for what they find.

MR. ROBINSON: Moving on to Section 4, the time-limited aging analysis. This covered neutron embrittlement of the reactor vessel and internals; metal fatigue of piping and components; leak-before-break analysis of primary system piping; fuel transfer tube bellows; crane load cycle limits; loss of pre-stress in concrete containments, and environmental qualification of electrical equipment.

Section 4.3.2 is where we had the confirmatory item. This concerned the environmental fatigue life correction factors. The values calculated were based on an assumed dissolved oxygen concentration data lower than .05 parts per million.

The staff questioned whether that number was the bounding number, and the applicant indicated that .05 ppm was bounding since they historically maintained its DO levels at less than .005. They did have administrative controls in place to maintain it at or below that level.

The applicant submitted additional information and confirmed their DO history since the plant began operation, and the staff found that this information was acceptable and closed out the confirmatory item, and revised the SER accordingly.

Moving on to the conclusion for Section 4, based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that the applicant provided an adequate list of TLAAs, per 10 CFR 54.3, and that the TLAAs will remain valid for the period of extended operation; that they have been projected to the end of the period of extended operation, and that aging effects will be managed for the period of extended operation.

Moving on to the overall conclusion, the staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that the requirements of 10 CFR 54.29(a) have been met.

That concludes the staff's presentation. Are there any questions?

MEMBER STETKAR: Questions from any members?

(No response.)

I would like to personally commend the staff on what I thought was, on this particular review, a really thorough job on the review of the scoping and screening analyses. I think it is one of the better ones that we have really seen. So I think you deserve some kudos for that.

With that, if there are no other questions, Mr. Chairman, well ahead of schedule, it is back to you.

CHAIRMAN BONACA: Do I have any additional comments from members of the public?

(No response.)

MR. HOLIAN: Mr. Chairman, this is Brian Holian, Director of Renewal.

I have one other item. It just half applies to TMI, and I do appreciate that scoping and screening comment. We are trying, both with a mix of the regional looks at scoping and screening and our audits, to combine hefty looks at that soon after the application comes in to make sure that is right.

I wanted to highlight one item that deals with that operating experience issue we talked about earlier. Next week, on Tuesday, Wednesday, and Thursday, we have representatives from all four Regions coming in for a license renewal counterpart meeting. I just want to highlight that. Some of the inspectors that are in the room today will be here. That doesn't happen often. Probably a year and a half or two years ago, that occurred.

It will be looking at items like operating experience. How well are our auditors doing it from headquarters? How well are the regions doing it? That is one aspect.

Another aspect is we've got four plants now that will enter the 41st year of operation, the extended period, this year, in 2009. Part of that regional look will be, how will we continue to look at the commitments they have made under license renewal, not only at that inspection right before they go into the period of extended operation, but under our normal reactor oversight process, make sure we are sampling license renewal commitments for throughout the extended period?

I just wanted to highlight that for the ACRS. You will probably hear or see some changes or finetuning to some of those inspection procedures or our audits.

That's all I have.

CHAIRMAN BONACA: And with that, we will take a break now until 1:45, I guess.

(Whereupon, the foregoing matter went off the record for lunch at 12:23 p.m. and went back on the record at 1:47 p.m.)

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

(1:47 p.m.)

CHAIRMAN BONACA: Okay. So let's move on to the next item on the agenda. That's Draft Final Revision 2 to Regulatory Guide 1.189, Fire Protection for Nuclear Powerplants, and Jack Sieber will take us through the presentations.

MEMBER SIEBER: Okay. Thank you, Mr. Chairman.

Regulatory Guide 1.189 has a long history. The first issue of that came almost -- actually more than 20 years after the Browns Ferry fire. And at that time, and up until the present time, the staff has been developing a comprehensive fire protection guidance document to identify the scope and depth of the fire protection features that the staff would consider acceptable for nuclear powerplants.

The latest revision of Reg Guide 1.189 is Revision 2, and that's the revision that we will discuss today. That is draft guide DG-1214. It was issued for public comment in April of this year, and the staff received 94 public comments, of which the majority were from NEI. A few comments were received from Florida Power and Light, and also Dominion

Resources.

Our Plant Operations and Fire Protection Subcommittee met on August 18th of this year to review Revision 2 of Reg Guide 1.189, and so that is the document that our focus should be on at this time. And so I would introduce the staff to make its presentation of the changes that are incorporated in Reg Guide 1.189, Revision 2. And to do that, I will introduce Sunil Weerakkody.

MR. WEERAKKODY: Thank you. My name is Sunil Weerakkody. I am the Deputy Director, Fire Protection, NRR. Sitting next to me is Dan Frumkin. He's a team leader in charge of part of the Fire Protection Branch that deals with these circuits and operator manual actions issues.

The staff's objective today is to present to you the -- one of the final products that -- or draft final products that we have worked hard, with a lot of inputs from the industry on how to address and disposition the multiple spurious circuit issue. To that extent, we have captured the staff's position into Reg Guide -- Revision 2 of Reg Guide 1.189.

And with that, I am going to turn it over to Dan, and he will provide the overview and the additional details.

MR. FRUMKIN: Thank you, Sunil.

For those of you who joined us for the subcommittee meeting, these slides are very similar, because I know we have some new members who haven't seen the background material, and then I have also tried to enhance the slides to answer some of the questions that came up during the subcommittee meeting.

So, first, I'll start off with the background for this change to the Reg Guide. Then, I will talk about the public comments, and there were three public comments, which were not incorporated initially. And then, we actually have some more information on those at this time. And then, the path forward, given the acceptance of this Reg Guide, or the issuance of the Reg Guide.

One of the slides that you will see is in color, and we have some copies for you.

So this is Slide 3. The proposed resolution to multiple spurious actuations came in SECY 06-0196. The staff proposed a resolution, and the Commission, in their staff requirements memorandum, was not -- did not accept the resolution that the staff presented in 06-0196.

They said it did not contain the necessary specificity, and they directed the staff to examine the licensee's analysis methods, use the normal public regulatory process to enable stakeholder engagement and developer-endorsed guidelines that provide a clearly-defined method of compliance for the plants not adopting NFP-805.

The staff has tried to follow this direction very specifically, and we will talk about in -- as I go through the rest of the slides.

There was a question -- this is a discussion of the rule language is what -- the problem that has been plaguing fire protection since 1980 is what exactly is required to be protected, and how is it required to be protected for Appendix R. And the rule says -- and I paraphrased -- or I have quoted it, part of it here. "Where cables or equipment of redundant trains of systems necessary to achieve and maintain hot shutdown conditions are located within the same fire area, one of the means of ensuring that one of the redundant trains be free of fire damage shall be provided."

And these are the traditional III.G.2 -- it's a typo, it's III.G.2 protection methods, which is the three-hour fire barrier, 20 feet to separation with no intervening combustibles with suppression and detection or a one-hour fire barrier with suppression and detection.

What I'm trying to point out with this quote of the rule is that only equipment necessary to achieve and maintain hot shutdown conditions is required to have the III.G.2 protection. This point was bought up in RIS 2006-30, I believe it was, and that has been the staff position. That is, if you have a train that is protected, a train that is required to achieve and maintain hot shutdown conditions protected, that the III.G.2 protection is not required.

So the staff took this clarification of the rule and decided that there were really two categories of equipment in the plant from a fire protection safe shutdown standpoint. There is what we have described in the Reg Guide as the safe shutdown success path, or also components required for hot shutdown, and they have also described as green box components because of the colors in the diagram.

And there is a component important to safe shutdown, and the safe shutdown success path components are those components that are described as the rule -- in the rule as requiring III.G.2 protection. Those are the components that are directly relied upon to maintain and achieve hot shutdown conditions.

The components important to safe shutdown, also known as the orange box components, are those components that could adversely affect the ability to safely shutdown through spurious operation or something. But otherwise, if they were to stay unaffected, shutdown wouldn't be affected.

So just to restate it, although both require protection under Appendix R, III.G, only the safe shutdown success path components, or the green box components, require Appendix R, III.G.2 type protection.

This is the diagram that I alluded to that was handed out just a moment ago, is that there is a green box, which contains the train of systems necessary to achieve and maintain hot shutdown conditions. This is what is required -- what is relied upon for safe shutdown. There are other systems, such as these orange ovals, that if they were to be spuriously actuated they could adversely affect the ability to safely shutdown, but they aren't on the hot shutdown success -- the safe shutdown success path.

So it's the staff position, based on this clarification of the rule, that these components would not require protection under III.G.2. So to give you an example of the scenario, for example, in the drawing in front of you, presume that the green box is a RCSE system as a boiling water reactor, and the large orange oval is the HPSE system.

Well, if the HPSE system could spuriously actuate, it would defeat the RCSE system by overfilling the reactor. But you don't -- you wouldn't need to protect the HPSE system in accordance with III.G.2, only the components of the RCSE system.

The HPSE system would have to be protected with -- it would have -- well, I'll talk about the methods, but if manual actions were credible to take -- to stop the spurious actuation, or if fire modeling was available to demonstrate that the HPSE system wouldn't be required under the same scenario -- or the HPSE system wouldn't be damaged under the same scenario that would require the RCSE system, then the licensees could justify less than III.G.2 protection.

MEMBER STETKAR: Dan, can you go back to the drawing? Because for the benefit of some other members who were not at the subcommittee meeting, the tank drain valve to the left of the tank, the orange component number 1, we had some discussion in the subcommittee meeting regarding items such as that.

And it's my understanding that, according to the classification scheme, that's always an orange component. It's not a part of the required for safe shutdown path, regardless of the size of that component. So, for example, if that component actuated spuriously and drained that tank in 45 minutes, it is still considered to be an orange in the -- for lack of complexity, an orange component within this classification scheme. Is that correct?

MR. FRUMKIN: That's correct. And I would even go further to say that in my HPSE/RCSE scenario, the HPSE system, if it were to spuriously actuate, would defeat safe shutdown using the RCSE system in a matter of minutes. And we would still define that system as an orange box component.

But based on the way that we structured the Reg Guide, if manual actions were not credible, or that a credible fire scenario could occur that would damage -- or that could cause a spurious actuation of that system, then protection would be needed. But it wouldn't be required literally for III.G.2. It would be needed to meet the intent of III.G as a whole.

MEMBER STETKAR: Okay. Let --

MR. FRUMKIN: And the goal there is to say that portions of Appendix R -- that green box is a very deterministic statement, whereas the orange box is more performance based.

MEMBER STETKAR: Okay. Let me go back and stay away from the spurious actuation of HPSE, which to me is not necessarily a bad thing, putting water in. I'm more concerned about spurious actuation of the drain valve that makes it not possible for RCSE to deliver flow for longer than some number of minutes. And I used an example of 45 minutes to drain down the tank.

That's a very specific time that I selected for a very specific purpose, but I want to understand why, if that valve were large enough, such that if it opened spuriously, it would drain that tank completely in 45 minutes, why that is not considered a green box valve, according to any of the criteria.

MR. FRUMKIN: Right.

MEMBER STETKAR: I want to understand that.

MR. FRUMKIN: And to answer your question, I go back to Slide 4, where it says, "Where cables or equipment of redundant trains of systems necessary to achieve and maintain hot shutdown conditions are located within the same fire area." The way that plans have designed their plants -- plants have designed their systems, the way that the NRC has always defined these systems, is that that tank and that drain valve would not be part of the redundant train.

And as we say in the diagram, the redundant train starts at the valve and ends at the container that we are trying to put the water in. So for sake of convenience, we have had to define the beginning and the end of the trains, and this is how we have done it. So --

MEMBER STETKAR: Does that make any sense? I hate to be that glib, but does it make any sense?

MR. FRUMKIN: It would --

MEMBER STETKAR: It would seem that there is a system here with two redundant trains, and that valve is a common element of that system. It happens to have two redundant trains that, in this particular example, you have named HPSE and RCSE, but I could call it train A injection and train B injection for a different other plant.

I guess we should continue. I think I've made my concern.

MEMBER POWERS: Is it that you have a particular affection for the three deterministic means of protection that are found in III.G.2?

MEMBER STETKAR: Yes.

MEMBER POWERS: You like those.

MEMBER STETKAR: No. I don't particularly like those. I want to understand why, because of the deterministic type of thought process, why that valve must always be an orange valve.

MEMBER POWERS: I suppose that it doesn't have to be, if a licensee chooses not to make it. All of the staff is saying --

MEMBER STETKAR: But if I were a licensee, I would -- and I were given the option, I would always make that an orange valve.

MEMBER POWERS: Because that opens up a wider range of fire protection measures that you can make.

MEMBER STETKAR: Right.

MEMBER POWERS: Whereas, within the green box you have to apply one of the three --

MEMBER STETKAR: Right.

MEMBER POWERS: -- whether or not they are effective. Okay?

MEMBER STETKAR: That's a different issue, Dana, but that's --

MEMBER POWERS: Okay. And so, I mean, I

don't -- it seems to me that what the staff has done is saying, "Okay. You've got to have one train that allows you to get to safe shutdown, and, in this particular circumstances of the green things we have to have these three measures, one of these three measures in place. Whether or not they are effective for that purpose, you have to have that.

Now, you may have to have something else, because they may not be effective. Okay? And they are just trying to limit the amount of things that come into III.G. They are not going to keep your valve untouched by fire protection hands.

MEMBER STETKAR: It is not untouched by fire protection. However, within the rule I can take credit for an operator manually closing that valve if it opens spuriously, if it's an orange valve. I can't do that if it's a green valve, regardless of what I'm doing as far as protecting the circuits for that valve. That's one fundamental difference.

MEMBER SIEBER: But all of this discussion is an artifact of the way the rule is written. It defines what the safe shutdown path is. So we're thinking broader --

MEMBER STETKAR: Well, but the licensee defines what the safe shutdown path is. The licensee could --

MEMBER POWERS: The licensee defines what the safe shutdown path is.

MEMBER SIEBER: He can choose a safe shutdown path. The rule says you've got to have one. Now, to have adequate fire protection, you may have to do other things, which is what is in the orange boxes. And you know that there is one hour plus recognition and thinking about it time for operator action, so you may have to do something before that in order to assure that you still have fire protection in regard to all of these orange components.

And I think that it is an artifact of the rule as to why you end up with this kind of a setup. It doesn't mean there is no fire protection.

MEMBER STETKAR: I don't see anything in the rule, though, that states -- in the rule that states that that valve has to be orange. I see things in the Reg Guide, because of the way the examples are organized in an example table in the Reg Guide that says that valve is an orange valve. I don't see anything in the rule that says that that valve needs to be --

MEMBER SIEBER: Well, it says "define the safe shutdown path" --

MEMBER STETKAR: Okay.

MEMBER SIEBER: -- which is --

MEMBER RAY: Yes. At the subcommittee meeting, the word "path," which is what Jack is pointing at --

MEMBER SIEBER: Yes.

MEMBER RAY: -- was given a lot of emphasis. And it was pointed out that the valve you are talking about now, John, isn't part of the path.

MEMBER SIEBER: That's right.

MEMBER RAY: And I gave up at that point.

MEMBER STETKAR: I think we should probably go on.

MEMBER SIEBER: Yes. Well, we shouldn't leave folks with the impression that it is not covered by fire protection requirements, because it is. It's just that it's covered in a different way, a broader way, than the safe shutdown path, where the rule has specific requirements for that path -- they are pretty narrow -- that you have got to meet. And I think that is what the distinction really is, as I understand it. And if anybody disagrees with that, you know, please speak out, particularly the staff.

MR. FRUMKIN: That's exactly a good characterization of this. And what we have always struggled with in the area of fire protection is this sort of regulatory creep where we draw -- we describe the path in one way, and then in one circumstance it might be significant, so we extend the path to perhaps a valve like this, and then maybe another plant would have something else that might be significant further down. And pretty soon everything in the plant requires III.G.2 protection, and that is where we get into the difficulty of having an unregulatable regulation.

MEMBER SIEBER: One just -- and I'm not trying to extend the time, but manual actions are allowed for components that are orange. They are not allowed for the operation of the green path items, and that is one of the distinctions. I mean, it has to work, and it has to be protected, so that it will function as designed. Whereas, the other ones you have a broader range of things that are allowable, provided that they -- you can analyze and show that they will be effective. And those are the important ones, as opposed to the path.

Okay. Why don't we --

MR. FRUMKIN: Okay.

MEMBER SIEBER: -- hopefully move on.

MR. FRUMKIN: So to describe the changes

in the draft guide, this was the primary change is this distinction between the safe shutdown success path and the components important to safety, or the green box and the orange box components.

And what we have included in the reg guide is for those components important to safety manual actions and fire modeling for assessing the safety is an allowable tool. But for the -- like as Mr. Sieber says, for the components, the safe shutdown components, manual actions and fire modeling is not allowed without an exemption or a licensing action, whichever is appropriate.

Examples of the safe shutdown success path components, and its importance to safe shutdown components, was added to the Reg Guide in a table as well. So that there can be some clarity when the licensees are doing their analysis of what requires III.G.2 protection, and then what they have additional flexibility to do analysis.

As was described, we got -- we received licensee -- comments from industry stakeholders only. No public stakeholders provided comments. The Nuclear Energy Institute provided comments on behalf of their members, and the Dominion company provided comments, and Florida Power and Light provided comments.

One of the comments that ran through as a theme for the -- from the industry comments was that NEI 00-01, Revision 2, should be referenced in the guide as implementing guidance. For the most part, this comment was consistent -- or this comment and the NEI 00-01, Rev 2, was consistent with the staff's position. And we endorsed 00-01, Rev 2, to the extent practical.

This keeps coming up, so I just made a table of the list of comments and how they were incorporated. Fifty-three of the 97 were incorporated, so we had a majority. Eleven were incorporated in part, and 21 were not incorporated, which I will talk about on the next pages. Nine were duplicates, and three were observations with no recommended changes.

The majority of the comments that were not incorporated or -- were due to statements about the guide should not supersede licensee's fire protection programs, and the guide does not supersede the licensee's fire protection programs, so no change was needed to the guide.

In some cases, there was guidance elsewhere in the guide, and other comments related to, you know -- related to the guide was being too restrictive, but within the guide there were means to deviate from the guide. So those types of comments were answered in the comment resolution sheets that you have seen.

And there were three specific comments that the NRC did not endorse, and these specifically addressed requests from NEI to endorse NEI 00-01. We have received a letter from NEI yesterday, and we have had -- or actually two days ago. We have had numerous discussions about their concerns on this topic of these three comments, and I think that the next few slides will show that the NRC staff and NEI are on the same page now with regard to these issues, which is a very satisfying outcome from the staff's point of view.

So the first issue had to do with the clearing of hot shorts within 20 minutes for components important to safe shutdown. During tests of DC circuits, though, the NRC staff identified that with two of those tests, two of 32 tests, the hot shorts within DC circuits did not clear, and the staff was reluctant to accept a deterministic limit for DC circuits at 20 minutes.

In NEI's letter of September 8th, they

proposed a change to their NEI 00-01 to remove DC circuits from the assumption that they would clear within 20 minutes. This is consistent with the NRC's position, so there would be no change to the guide as it has been presented to the -- the version that the ACRS Committee has seen. So we are consistent on this issue.

Appendix E of NEI 00-01, operator manual actions, the NRC staff had numerous concerns with this appendix regarding the liability of manual actions being dealt with explicitly in the guide. And also, we had discussions with industry stakeholders that indicated for some scenarios the Appendix E timelines may not be conservative, but in other scenarios it may be appropriate.

So the NRC staff position is that Appendix E is not sufficient to address all plant response scenarios. We have discussed this position with NEI, and the staff's position -- I think NEI agrees -- is that there be value in taking Appendix E back, taking more look at scenarios, what timelines would be appropriate for which kind of scenarios, and to build an effective manual actions implementing guidance document.

But it's the staff position that this

implementing guidance on manual actions is not necessary to bring the circuit failure issue to closure, and we would prefer not to delay this Reg Guide to incorporate industry implementing guidance on this issue.

The third issue that the NRC staff did not initially endorse was the NEI 00-001, Rev 2 position that only one cable be considered to have hot shorts for non-latching, non-locking circuits, and that concurrent multiples faults in separate cables need not be considered.

So to paint the picture, this is only relating to components important to safe shutdown. Components in the green box, the safe shutdown success path components, would have to consider all possible hot shorts in a fire area.

But for this case, the industry felt that for the orange box components, where components would have to latch in, or would have to -- these are non-latching components, so the primary circuit would have to come in at the same time a secondary circuit would have to have the same hot short to actually a circuit that could prevent safe shutdown or impact safe shutdown.

The NRC staff expressed concerns with this proposal during the ACRS subcommittee meeting. The data shows that this happens one in 100 times or so of the test data. The test data isn't -- didn't specifically address this issue, so the staff was not comfortable with this position and planned to not endorse it.

In the September 8th letter, NEI came back with a proposal to assume that two separate cables would experience concurrent hot shorts for non-latching/non-locking circuits, but they would draw the line there and say we wouldn't consider three.

The NRC took a -- considered that proposal, the NRC DRA staff of NRC, and felt that that proposal was sufficient for a deterministic analysis in this case. And the following three bullets we intend to incorporate into the Reg Guide where appropriate. Specifically, licensees should consider concurrent fire-induced circuit faults in two separate cables where defense-in-depth features are present.

And this addition of defense-in-depth features is a staff addition, because if there are cases where it is very likely that there will be multiple cable faults, then we would question whether there is defense-in-depth in that case.

There should be, you know, perhaps

suppression systems in the area, sufficient distance between ignition sources and fire sources, and cables of -- safety cables. And where there isn't suppression or distance, we would probably -- the threshold of defense-in-depth would not be met.

For high-low pressure interfaces, the NRC staff believes that because of their significance that three cables should be considered, and so this is a higher threshold for the high-low pressure interfaces. And for multi-conductor cables, all circuit faults that could occur within the cable should be assumed to occur.

In the September 8th letter, the licensee said that they would only consider two faults in a single cable. The testing that the NRC staff has seen indicates that once you have a single hot short within a multi-conductor cable, all of the conductors in that cable are likely to experience a hot short.

So this is much more significant -- this is much more than just one hot short and one cable and another hot short and another cable. This is as many hot shorts as could occur in one cable, and as many hot shorts as can occur in a second cable. So it could be three, four, five, or even more hot shorts in these two separate cables.

This last bullet is also a difference from the September 8th position that NEI came in with, which was for two. But we have since had conversations with them, and they seem to be on board with this assumption as well.

MEMBER RAY: So the statement that a limit needs to be established to avoid introducing chaos into the analysis, which was the industry response earlier, at least is bounded by what you foresee.

MR. FRUMKIN: Yes, right. And the limit --

MEMBER RAY: The limit will exist.

MR. FRUMKIN: Yes, the limit is one or two more than originally presented by the NEI.

MEMBER SIEBER: There is another issue I think that is involved with -- particularly with motor-operated valves. You know, the cables that go to the operating mechanism of motor-operated valves, there are certain operating conditions where the protections within the valve are bypassed. So if you get a closed signal to a valve, and the protection is bypassed and the valve goes closed, that motor keeps turning until it burns out, and the valve is jammed and manual operator action is insufficient to open it.

So that is one of the reasons why the

shorts issue is mostly shorts as opposed to grounds and open circuits. That's why this is important to consider.

MEMBER RAY: You are satisfied, then, with what is being proposed?

MEMBER SIEBER: Well, this is better than what we had before, because it now allows a larger range. It requires analysis of a larger range of possibilities with regard to what can happen and what you can do about it. And, you know, the idea of having to deal with a lot of things going on at once is where the word "chaos" came from. On the other hand, you have to deal with chaos to solve the problem, in my view. So we might as well just face that.

MEMBER RAY: This does that adequately?

MEMBER SIEBER: Yes. Well, we'll get to my issue a little later on. Okay?

MEMBER RAY: Okay.

MEMBER SIEBER: Yes. Be patient, but it's worth waiting for.

(Laughter.)

MEMBER ARMIJO: Dan, I would like to as a question.

MR. FRUMKIN: Oh, sure.

MEMBER ARMIJO: In the subcommittee charts, the NEI suggested that the Reg Guide be deferred until more DC circuit testing is completed as an alternative. Have they changed their mind on that?

MR. HUTCHINS: Steve Hutchins from NEI.

MEMBER SIEBER: You might need a microphone.

MR. HUTCHINS: Steve Hutchins from NEI. Yes, we believe that we could work with the Reg Guide the way it is. And if we have to come back next year after we review the results, properly disposition the results of the tests, we could come back and do something for DC. We realize that DC, because of ungrounded systems, you can't have some high impedance faults, some faults that would last longer than 20 minutes. So we backed off on that requirement.

MEMBER ARMIJO: Thank you.

MR. FRUMKIN: So just to summarize, the NRC staff view is that there is sufficient guidance available for licensees to complete the fire-induced circuit analysis, and this is consistent with the direction from the Commission. The NRC staff has come to resolution on the two issues that were identified in NEI 00-01.

And as you remember from -- or as was

discussed in the subcommittee meeting, these two issues were the number one and number two issues of NEI. The manual actions issue was their third priority, and I think we have gained some insights into what they were thinking, and they have gained some insights into what we were thinking.

And I think that the -- developing refinement of the implementing guidance for manual actions is something that we will be working on. But, again, it is not necessary at this time.

And our plan is to get ACRS endorsement of the guide and issue the regulatory guide in -- before the end of this calendar year. The issuance of the regulatory guide will start a clock on the enforcement guidance memorandum, EGM 09-002, with which licensees will have six months to identify their non-compliances, and an additional 30 months to resolve those non-compliances.

So what is going to happen when this Reg Guide is issued is the licensees will begin work -- for those licensees who haven't done this level of detailed analysis, they will do work to identify issues or deficiencies in their design, and where they have such issues they will -- they come up with a corrective action plan.

And, in addition, to support our inspectors we plan to revise our inspection manual to assure that licensees are appropriately implementing the clarification as described in the Regulatory Guide 1.189.

So that concludes the slides.

MEMBER SIEBER: Yes. I have a couple of questions that I need to ask. At the time of our subcommittee meeting, we had a copy of -- it was a draft copy of a proposed Reg Guide 1.189, Rev 2. And that was in our hands the copy of record when we did that review at the subcommittee meeting.

Now, yesterday I got an e-mail that had -- included a letter from NEI and a revision to NEI 00-01, very timely, 24 hours before the meeting, and an indication from the staff that they think that this solves the problem, and that there will be an additional revision to the draft copy of Reg Guide 1.189, Rev 2, before it is issued.

Now, is that a correct interpretation?

MR. FRUMKIN: The only intended change to the draft copy of record for ACRS is the addition of the concepts of these three bullets from this slide, which is to consider that we -- in the draft Reg Guide we say we do not endorse this concurrent hot short position. We would replace that with the position to look at two hot shorts with defense-in-depth, three hot shorts for high-low pressure interfaces.

MEMBER SIEBER: So a short answer would be yes?

MR. FRUMKIN: A short answer would be yes.

MEMBER SIEBER: Yes. You will have to modify the guide of record that we were reviewing in order to accommodate the last couple of -- the information in the last couple of slides and a reference to the NEI guide, which I understand there is printed words, but not yet incorporated into the guide.

And that now becomes a problem for us. I cannot write, nor do I believe the committee can send you, a letter endorsing a regulatory guide where we don't have a final copy with concurrences, and that the references to which it calls upon for the details of implementation are not published.

CHAIRMAN BONACA: Well, we don't --

MEMBER SIEBER: And so on that basis, I think that when you get that work done, and can provide us with a copy of the guide that you intend to issue, with the concurrences, we can review that along with the change to NEI 00-01, which should be a relatively short process, since we have now reviewed some of the background on that.

I think at that time we can prepare -- be prepared to make a decision as to whether we endorse Rev 2 of the guide or not. But right now I don't -- just because of the mechanics of how we do business, we cannot endorse something that is not finished.

And so that is sort of the way I think we stand, unless I get different direction from the other members and the Chairman, or anybody else that interprets the rules differently than I do. Yes?

CHAIRMAN BONACA: We normally don't comment on documents which are not complete.

MEMBER SIEBER: Okay. So I guess that is where we are.

MR. WEERAKKODY: We understand. We will transmit to you an official copy for your records. I believe -- I think you didn't say -- you are not saying that we need to come back to the --

MEMBER SIEBER: Yes. And the schedule for that -- if you want to finish by the end of the year, and there are no additional problems, the schedule is a pretty tight one, but the document -- Reg Guide, draft Reg Guide, needs to be complete and concurred in. And we have requirements for a notice in the

Federal Register, and that notice begins after next week's meeting where we decide what next month's agenda will be.

So, you know, I would suggest rapid -- rapid --

MEMBER ARMIJO: You are not proposing another subcommittee review of the Reg Guide, just --

MEMBER SIEBER: No, not another subcommittee review.

MEMBER ARMIJO: -- directed to the full committee.

MEMBER SIEBER: I think that if I get the document, and we have a presentation that goes through the changes to the full committee, that would be sufficient, unless somebody else -- another member --

MEMBER STETKAR: Ask NEI, will the draft changes to NEI 00-01 also be available?

MR. HUTCHINS: Yes.

MEMBER STETKAR: Okay.

MEMBER SIEBER: Well, it would be good if that were actually incorporated. And there was a plan to do that without reissuing the whole document under the NEI process. And as I understand that the text is complete, I do -- I did get a copy of what appeared to be a complete copy.

MR. WEERAKKODY: I have a clarifying question.

MEMBER SIEBER: That would be a necessary part of the review.

MR. WEERAKKODY: I have a clarifying question. I think definitely we understand the need to send you an official copy of 00-01 and the Reg Guide revised --

MEMBER SIEBER: If you want something from us, we have to meet the --

MR. WEERAKKODY: But I am assuming -- or, rather, our preference is to answer any questions or concerns you have today as opposed to --

MEMBER SIEBER: Yes. And I'd like to open that up, because if there are comments that the members have, or questions to ask, now is a good time to do it. We have the time, and I think we have a pretty good direction as to where we are headed. So this would be an appropriate time to --

MR. WEERAKKODY: The reason I said that it is our preference is for -- the main reason is we spoke to the three main changes. But if the committee feels, after looking at the revised guide that you need to bring us in, we will be more than happy to be here.

MEMBER SIEBER: So let me open the floor to the committee members, if they have additional questions on what has been done so far.

MEMBER MAYNARD: I guess I would just like to comment. We have in the past approved things based on incorporation of comments, without having that necessarily brought back to the committee. Now, I don't have a problem with waiting until the next meeting, or doing something like that, but we have in the past approved documents based on changes that were discussed in the meeting, based on the incorporation of those.

So I am not sure that we are required to wait until we get a final document. But I will just toss that out.

MEMBER RAY: Well, the difference, Otto, would be of course that -- something subject to comments on what Jack is looking for, which is the official document, rather than acknowledging that the document we have is going to be changed. That would be a difference I think.

MEMBER SIEBER: Well, you don't know how it is going to be changed. You have -- two days ago there was a good idea. Tomorrow there may be another good idea, and we won't know about it.

MEMBER RAY: I was just trying to respond to what Otto had said.

MEMBER SIEBER: Yes.

MEMBER RAY: It seemed different to me, although at first I did have the same feeling you did.

MEMBER SIEBER: Yes.

MEMBER STETKAR: One example is what is up on the screen here, which is the -- in my mind the substantive technical change to the guidance. And under the first bullet there, there is a caveat after the comma that says "where defense-in-depth features are present." And I was curious whether the Reg Guide, in its final form, will elaborate on what a defense-in-depth feature might be, since this is a deterministic-type analysis.

So, you know, when in practice as a licensee do I need to consider two cables or not? Because there apparently is that caveat in there that I only need to consider them when it affects something called a defense-in-depth feature. And I don't yet know what that means.

MEMBER SIEBER: Okay. Well, that would -- does the staff want to respond to that?

MR. FRUMKIN: Sure. Let me just take a step back. I think the point that you made -- this is actually the only change that is recommended to the guide of record. There would be no change to the guide on manual actions, and there would be no change to the guide that you have seen on the DC circuits, because the position is -- remains the same.

And, again, perhaps I was misled, but what Dr. Maynard said about providing information, that was -- our intent is to provide this information in writing to the committee as a step towards getting it incorporated -- or getting approval for that in accordance with this. And I might have misunderstood the process.

But the Appendix R and the deterministic methods of Appendix R are very -- fairly clear on what defense-in-depth is, fire protection defense-in-depth, preventing fires, suppressing fires, and ensuring there is the ability to safely shut down. I believe it is described -- you know, it is described in Appendix R, the rule itself. So I am not sure what more we would have to say to the licensees about explaining what defense-in-depth features were.

MEMBER BROWN: Is this AC? I saw the DC circuits. When I read the other stuff, I saw the reference to AC. Is this AC circuits only?

MR. FRUMKIN: Well, in a way.

MEMBER BROWN: It's two -- two concurrent firing circuit failures in two separate cables with those, but yet we are not doing anything with DC.

MR. FRUMKIN: Well, in a way it is de facto AC, because DC wouldn't be -- concurrence wouldn't be an issue with DC, because we wouldn't assume that they would ever clear. So only AC circuits would be assumed to clear, and --

MEMBER SIEBER: That's right.

MR. FRUMKIN: -- and not occur concurrently.

MEMBER SIEBER: And the protection schemes on DC sometimes won't operate when the fault is not a solid fault. It doesn't seem to show that in a couple of the cases.

Any additional questions from the members?

MEMBER STETKAR: I think --

MEMBER SIEBER: I think your question is one worth pondering for a little bit. Maybe when we come back to meet again, you can give us a little bit more insight into -- in the form of examples --

MEMBER STETKAR: That would be good.

MEMBER SIEBER: -- that would help us fully understand and appreciate the wisdom of all this.

If there are no additional questions, I would like to thank the staff very much. And I think that we are reaching a conclusion. It is unfortunate that we can't provide a letter report on a document that is not finished, but I am sure that you understand our position. And I would remind all of the FOIA requirements, and so forth, that getting on the agenda would -- soon would require some rapid action.

Thank you very much.

Mr. Chairman?

CHAIRMAN BONACA: We are becoming extremely efficient.

(Laughter.)

MEMBER SIEBER: Thank you, sir.

CHAIRMAN BONACA: We are well ahead of schedule. I think what we should do, we have a number of subcommittee reports tomorrow --

MEMBER SIEBER: Oh, okay.

CHAIRMAN BONACA: -- that are not on the record. So we could go through one or two of those.

MEMBER SIEBER: Wait a minute.

CHAIRMAN BONACA: And then take a break, as we were scheduled to do. And then we'll get back on the record for the next presentation, which would be at 3:30. At 3:15 we have a break.

MEMBER BROWN: I lost the bubble of what -- we are going to do a couple of reports?

CHAIRMAN BONACA: A couple of reports until 3:15, then we take a break as the schedule --

MEMBER BROWN: Oh, okay.

CHAIRMAN BONACA: Okay?

MEMBER BROWN: Okay. Yes, I got it.

CHAIRMAN BONACA: And then, at 3:30 we get to the draft digital I&C.

MEMBER BROWN: Yes. Well, George has got to be here for that.

CHAIRMAN BONACA: That's right. So we have to wait for him.

(Whereupon, the proceedings in the foregoing matter went off the record at 2:38 p.m. and went back on the record at 3:30 p.m.)

CHAIRMAN BONACA: We are back into session, and the next item on the agenda is the Draft Digital Instrumentation and Control Research Plan for Fiscal Years 2010 to 2014. And George will take us through that presentation.

MEMBER APOSTOLAKIS: Thank you, Mario.

This is the third plan, I believe, that the staff has put together, the third five-year plan.

And we had a subcommittee meeting in August where we reviewed the plan and other things, but we are only focusing on the plan at this time, and the staff expects a letter from us.

I would just let the staff go and start the presentation. Okay. Who is first?

MR. SYDNOR: Thank you, George.

My name is Russell Sydnor. I'm the Branch Chief of the Digital I&C Branch in the Office of Research, Division of Engineering. And with me today is Daniel Santos, who is a Senior Technical Advisor for Digital I&C, also with the Office of Research.

I would just also like to introduce our Deputy Division Director, Stu Richards is here supporting us, and Deborah Herrmann from -- his Senior Technical Advisor for Digital I&C from NRO. And also, we have Mr. Richard Stattel, who is Digital I&C Engineer from NRR, the Digital I&C Branch of NRR.

Our purpose here, as George stated, is to obtain a letter of endorsement for the updated plan. And this is the -- as you mentioned, the third in a series of plans that have been transitioning.

I want to discuss and obtain insight from ACRS. We had a number of good comments from the Digital Subcommittee, and we have captured those. And we will also be going through the transcripts of that meeting, because there were some very specific comments that we need to capture and make corrections to the research plan, and --

MEMBER APOSTOLAKIS: This word "endorsement," what exactly does that mean? My understanding is that the plan is still in process. I mean, there may still be some changes later.

MR. SYDNOR: It has not gone through final concurrence. We are going to incorporate ACRS comments and feedback, public comments and feedback, and then go to final concurrence, Office Director.

MEMBER APOSTOLAKIS: We will not see that final product, will we?

MR. SYDNOR: We are not anticipating any major changes based on what we have seen so far. The most significant comments we have gotten were from the subcommittee, and I will talk a little bit about why that is, because of the process we have gone through to get to this point.

MR. SANTOS: This is Dan Santos, Office of Research. We issued the plan to the public for more than a month. As of today, we haven't received any public comments or industry comments yet. That doesn't mean we will continue to solicit them, but --

MEMBER APOSTOLAKIS: But we will have to make sure that the -- whatever comments we make, make sure we are referring to a specific date of the plan.

MR. SANTOS: Yes.

MEMBER APOSTOLAKIS: Because that word "endorsement" confused me. Have we ever written a letter that says "endorsed"? Never. I don't think we ever did that. So we will have to be creative in the English language.

MR. SYDNOR: We would be open to other words.

MEMBER APOSTOLAKIS: Okay.

MR. SYDNOR: "Approve" or --

MEMBER APOSTOLAKIS: Like "disapprove."

(Laughter.)

I am a foreigner. I don't know.

MR. SYDNOR: Primarily, we are looking for your feedback, and we have gone through an extensive effort to get to the point with the updated plan and internal review that we will talk about briefly. But also, we are -- you know, with the committee's broad outlook on all sorts of issues across the nuclear power, we are looking for -- or is there something we're missing that you have seen in other areas that we should think about incorporating.

Like we mentioned, this is -- the plan is a tool that we use and we update -- currently we are updating on a five-year basis. This is the third in a series. We are currently working the '05 through '09 plan.

We have -- in that plan there are -- in the current plan we are working there are seven research program areas, and there are system aspects of digital I&C, software, quality assurance, risk assessment, security of digital safety systems. We look at emerging technology, advanced reactors, and we have collaborative research and standards. Those are the seven program areas that are in the current plan, and those are further broken down into like 21 -- 29 research projects and tasks that we are currently working.

And we have made significant progress in 21 of the 29 areas. We have produced almost two dozen -- delivered approximately about two dozen research products, everything from NUREGs to Reg Guides to DOE lab reports, things of that nature. And we have -- 17 of those are still currently in progress, and some of those we will be carrying over and we will be talking about those as we go through the new plan.

MEMBER APOSTOLAKIS: Now, let me ask

another question here. There have been two five-year plans that have been completed. Have there been any products that are actually being used by decisionmakers, like at NRR?

I mean, we had a very interesting committee meeting a few years ago when somebody from NRR said that, "I have never seen a report from Research that was useful." So have we changed that now? Have you guys produced tools or algorithms that real decisionmakers, reviewers in the agency, are actually using? What are you proud of?

MR. SYDNOR: There are a number of products that are in use, primarily I would say Reg Guides that have been produced under the previous plans. There is a lot of research that is currently underway, some of which the committee is aware of and some maybe not. And we can about some future presentations that we can -- where we can change that to get you more involved in the current research.

But there is a lot of -- for instance, the interim staff guidances that were developed under the Digital I&C Steering Committee, a number of our research projects we're working in those areas. And what we did was tailor that research to support those ISGs. That's one example of something fairly recent.

There is also current work in progress. The committee heard about Mike Waterman's work in the diversity area, and we are trying to develop a new tool there and publish a NUREG that would support that tool.

So there is a number of examples of that.

MEMBER APOSTOLAKIS: You heard this committee, and you have read a few of our letters that keep coming back to the theme of failure modes. And do you think that five years from now when you come in with a fourth five-year plan you will be able to say, "Yes, we have made significant progress there"? Because right now it seems that we are not really there yet.

MR. SYDNOR: You'll see as I go through the new plan one of the major research areas is in that area. And it is geared toward trying to answer what have been what I call some of the tougher questions that have come out of those discussions. What are the fire modes of concern? You know, what is a software failure? For example, things like that. We have been following the committee's advice on PRA research, and things like that, and --

MEMBER APOSTOLAKIS: Are you -- I'm sorry. Go ahead. Keep going.

MR. SYDNOR: -- and your recommendations. There has been SRMs from the ACRS and from the Commission to investigate --

MEMBER APOSTOLAKIS: We don't issue SRMs.

MR. SYDNOR: -- and we are going to talk about those.

MEMBER APOSTOLAKIS: I know it's not relevant perhaps, but are you happy with the number of resources you have? I mean, in the agency you have enough people?

MR. SYDNOR: I won't say that resources haven't been an issue. They have been an issue for all digital I&C across the agency over the last two to three years. The agency has gone through a fairly large transition there and restaffing effort. Over the two-year or two-and-a-half-year period I have been in Research, we went from being about 50 percent staffed out to about 20 percent staffed, and then went through a whole restaffing effort.

As we are currently speaking, I am just about fully staffed. But a lot of those are new to the agency, and so there is, you know, a training timeline with a lot of those folks. Though right now staff is not an issue, but it certainly has been an issue in progressing some of the research and maintaining steady progress.

MEMBER APOSTOLAKIS: The problem is that there are no universities that produce graduates in this area. I don't know of any. I mean, computer science departments don't do things like that. They don't look for failures.

MEMBER BROWN: They don't do what?

MEMBER APOSTOLAKIS: They don't train students to look for failures, failure modes, what is wrong with this. It is always, you know, a new computer language or you have to learn that on the job, I think, unless your experience is different.

Okay. That was a parenthesis we just closed.

MR. SYDNOR: Before we leave this slide, I will just mention that, you know, although I -- the slide mentions that we have made significant research progress in a majority of the areas, and some of that has been continuing research that you mentioned, it is not like each five-year plan was executed closed, executed closed.

A lot of this research is -- takes years to work through, but there are some topics that were not addressed, and for a number of reasons they didn't reach a priority, a regulatory priority. It turns out that the research area is better addressed by the industry, things of that nature, or they haven't become a pressing issue for the agency.

And so I just mention those topics, because they are not going to be included in the new plan, even though they were in the past plans. And that has been reviewed, as I am going to cover in a minute, by the other offices. And they agree with that.

MEMBER ARMIJO: Could you define what COTS and THD, what those things mean?

MR. SYDNOR: Oh, I'm sorry. It's commercial off the shelf.

MEMBER ARMIJO: Commercial off the shelf, okay.

MR. SYDNOR: And, actually, the industry has done a lot of work there in addressing how you -- how an applicant needs to address that issue. And total harmonic distortion is -- we have retained one project that is looking at power supply effects on digital I&C, which we will talk about later. But none of these rose to the level of needing -- you know, reaching a priority where we initiated research, even though it was an idea in the old plant.

MEMBER APOSTOLAKIS: Let me -- I'm

curious. You have already approved some digital I&C, or NRR has, right? No? You have to come to the microphone. I'm sorry to do that to you.

MR. STATTEL: I am Richard Stattel from NRR.

MEMBER APOSTOLAKIS: Is that okay? Can you hear him? Yes, you are okay.

MR. STATTEL: Hello? Okay. That's good. Yes, I'm Richard Stattel from NRR. So you are asking about -- well, recently we approved the application for the Wolf Creek main steam isolation system, so that was a digital application. And we applied several of the principles that we received from the research projects.

MEMBER APOSTOLAKIS: I guess my question is: if I wanted to be a hostile reviewer here, which I don't want to be, you are telling me on the one hand that we don't understand the failure modes, we are still working on them; on the other hand, that you approved something. So did you approve it without understanding how it can fail? Is there a way around it?

MR. STATTEL: Well, we basically enveloped the process. So basically in the failure modes and effects analysis, that isn't a required document that we received from the applicants. Because software failures, for example, it's not easy to quantify or really determine the failure modes easily for those types of systems, the approach that is taken by industry, and that is presented to us, is basically to identify the effects of those faults, and address the effects of those faults without going into the specifics.

So, in other words, in terms of lines of code, we are not going to go down to the level of line 20 of this particular code fails in this particular manner. But we will address the effects where the code halts execution, or we come up with basically a subset of failures that would be paused by those software errors per se.

And that's the effect that we are currently -- that's the approach we are currently taking and that we are reviewing to those levels. But, of course, we have ongoing research projects that would take it to the next level, if need be.

MR. SANTOS: I just want to -- Dan Santos again -- to add that to deal with some of those uncertainties we also -- that's why we take into account and look at defense-in-depth strategy, diversity, redundancies, independent strategies, to help account for some of the uncertainties associated with our state of knowledge of failure modes.

MEMBER APOSTOLAKIS: Is this your --

MR. STATTEL: It receives an actual signal from the reactor protection system, and it operates the valves, the main steam and the feedwater isolation valves. That's basically the extent of that system.

MEMBER APOSTOLAKIS: They operate --

MR. STATTEL: It sends the control signals out to the field to operate those valves, so it has certain logic built into it. And because it is a digital implementation, we had a certain required diversity -- diverse actuation functionality requirements for that system.

MEMBER BROWN: Is it a software-based system or an FPGA?

MR. STATTEL: It's an FPGA-based system.

MEMBER BROWN: That's not a -- that's a hard-wired digital system. It's not a software-based system. So the answer to your question is no.

MR. STATTEL: Well, in actuality, there is software that is used in the development of that system.

MEMBER BROWN: But when you -- the chips themselves are fixed --

MR. STATTEL: That's correct.

MEMBER BROWN: -- logic, you don't have code within the chip. So it's not software-based.

MR. STATTEL: Right.

MEMBER BROWN: It's combinational logic burned into a chip. So it is not like the ESBWR protection or safeguards in the Oconee, etcetera, etcetera. So when I said no, and somebody else said no, the answer is no. This stuff is effectively analog.

MEMBER ARMIJO: It's a diamond chip.

MEMBER BROWN: Yes, it's analog combinational logic. You can do digital in a number of different ways. The issue on comp software failures is software-based systems, not FPGAs. However you develop the logic scheme, that's a different circumstance. That is often a design tool that you use. I'm just trying to clarify --

MR. STATTEL: The tools themselves can contain faults and errors.

MEMBER BROWN: No, that's -- I'm not arguing about that. Okay? The point is it's -- this hardware you put in is not software-based.

MR. STATTEL: That's correct, for that particular application. Now, we have also just drafted the safety evaluation for the Oconee application, which is software-based. And we have used a lot of the effort from Research to back up that, to perform that evaluation as well.

MEMBER BROWN: We haven't been asked to look at that again yet. All we've had is that one briefing.

MEMBER APOSTOLAKIS: Okay. Maybe we can -- thank you very much.

MEMBER BROWN: I know I made some comments which people weren't happy with, so --

MR. SYDNOR: I just wanted to spend --

MEMBER APOSTOLAKIS: You can always ask, Charlie.

MEMBER BROWN: Pardon?

MEMBER APOSTOLAKIS: You can always ask. Don't be shy.

MEMBER BROWN: I presumed it was coming to us, if they are going to do an upgrade. It's a complete reactor protection system upgrade.

MEMBER APOSTOLAKIS: Okay. Mr. Sydnor?

MR. SYDNOR: Okay. I just wanted to spend just a brief -- talking about the process we have gone through for the update, because it addresses one of the previous questions on, you know, why do we expect, you know, no more drastic changes to the plan other than what were presented to the subcommittee?

And we really started working on this update over a year ago, and we went through an extensive internal review process at the working level, and branch chief level, to -- with all of the offices -- NRR, NRO, NSIR, NMSS -- to receive comments and feedback on, you know, what are the viable -- what are the research topics they are still interested in? What are the ones we see that there is questions still to be answered? And where have we, in fact, received direction from the Commission or the EDO's office for specific efforts?

And so we have gone through that process. We did receive a lot of comments. The slide -- the overhead mentions a few of them, including supplying training when needed, and that is something that we can do on an individual project basis for the other offices, either formal or informal training. Leveraging existing information, and not duplicating efforts, those are your kind of typical comments.

A significant comment was to continue the digital I&C PRA work, both from the PRA groups and the user offices, and also from the Steering Committee. We have long-term interest in trying to solve that issue, and the ACRS has heard about the past work in that area.

A new issue that we received some input on -- and this is where we have some things in the new plan that weren't in the previous plans, because they weren't issues then, but now they are -- and one example is the use of automated tools in developing software and software engineering design. We'll talk about that a little bit.

And also, like we were discussing previously, improve the understanding of failure modes and effects on the systems, and really try to answer some basic questions there that have not been answered in the past.

And provide specific deliverables. Obviously, that goes to your earlier question about, you know, developing -- not just doing research for research's sake, but trying to provide useful products for the licensing offices.

MEMBER ARMIJO: On those useful deliverables, is there schedule requirements, dates at which these deliverables have to be ready? Is that part of the plan?

MR. SYDNOR: If there are specific dates that the user offices request, then the answer is yes.

Also, on a project basis, obviously we set up dates with the -- whoever we are contracting the research with, whether it is a lab -- university laboratory or a DOE lab, we set up dates and schedules with those. Obviously, when you are dealing with state-of-the-art research, achieving a -- you know, a true milestone schedule is always difficult, and there are issues.

We respond to changing priorities within the agency, changing direction. The Steering Committee gave us a lot of changes in direction over the last couple of years, and so we responded to those. So we respond to agency needs, and we don't let the schedule drive everything we do. But certainly we do try to adhere to schedules to, you know, produce our --

MEMBER APOSTOLAKIS: But the plan itself, I mean, has the projects at least -- deliverables explicitly -- must be a date --

MR. SYDNOR: Yes, that's correct.

MEMBER APOSTOLAKIS: -- with the understanding that, you know, that doesn't mean that all of the problems have been solved by that. But there is a deliverable at a certain date.

MR. SYDNOR: There is in the plan -- Dan is reminding me that in the plan we did include a high-level schedule. The level of detail we put into that schedule is a higher level than was in the '05 through '09 plan.

If you look at the current plan, there was a pretty significant level of detail for each of the research projects. But what happened, as soon as that plan was published, that schedule was immediately out of date. And so we are looking at other tools to -- for a lot of good reasons. We are looking at other tools on -- using some online tools to have current schedules available to the user offices, so they can look at our website and see whatever they need to see.

VICE CHAIRMAN ABDEL-KHALIK: On the understanding of the failure mode, is a major part of that compilation of data from other industries?

MR. SYDNOR: Yes, we'll talk about that when we get to that research stuff, if that's okay.

VICE CHAIRMAN ABDEL-KHALIK: Okay.

MR. SYDNOR: Because that is in the new plan. We'll address that specifically.

VICE CHAIRMAN ABDEL-KHALIK: All right.

MR. SYDNOR: So the updated research plan has five program areas, and you will see them in -- represented in this chart, and we will just -- our intent here today is at a high level to talk about each of the topic areas in those five program areas. And some of them bear more discussion than others, as you will see as we go through, because some of them are -- address these controversial topics, and some of them are just more continuation of things that we have done in the past, collaboration and things like that.

So the first program area is our biggest one, and the safety aspects of digital systems. It has seven topic areas, and we will go through each of those and give you a chance to ask questions on these.

The first one is a new idea that was generated from some in-house discussions, and really stems from the fact that we have done a lot of work looking at individual safety systems or looking at network or network security or safety system security. But we haven't really taken a step back and looked at, you know, how it all fits together.

So the idea on this one was -- and using in-house effort to develop a -- what we call a generic abstract model for plant-wide digital systems that is going to look at communication protocols and data protocols that have to occur across the whole plant in I&C systems.

And the idea is to gain a better understanding of what are going to be network-based challenges to reliability, redundancy, and independence among systems. And so we have not started this as a new idea. We haven't started this research yet. But as this was an idea that bubbled up from some of my senior engineers working in this area, and was accepted by the other office as a viable -- what we hope will be a viable tool.

MEMBER APOSTOLAKIS: I guess maybe we can have a little discussion on the words "generic abstract model." What exactly does that mean? I mean, it will be generic applicable to all reactors?

MR. SYDNOR: Generic to nuclear powerplants. A lot of the I&C systems that are common to -- and data information flow that is common -- you've got protection systems, actuation systems, control systems, you've got post-accident monitoring, you've got plant data networks. A lot of the structure is very common, and so we are looking at, do we really understand how that is all going to fit together in a digital and a highly integrated plant, and a network structure?

MEMBER APOSTOLAKIS: So the challenge is also generic? Reliability, redundancy, independence? I mean, I am just wondering how far you can push a generic model.

MR. SYDNOR: And I'm not sure we know the answer to that yet. You know, that we are going to explore this model, and when we discussed this in more detail at the subcommittee there was a lot of question. I mean, well, what is this model going to consist of?

We don't see it necessarily as a -- you know, a computer-based or, you know, a software model. It could be oversimplified, a block diagram model that captures all the requirements and needs, and, you know, how these various data needs, control needs, protection needs, how they all have to communicate and talk to each other.

VICE CHAIRMAN ABDEL-KHALIK: Can a future applicant use that as a DAC?

MR. SYDNOR: I'm not an expert on DAC, so I'm --

VICE CHAIRMAN ABDEL-KHALIK: But conceptually, I mean, is that what you are trying to do?

MR. SYDNOR: I think what we are trying to do --

MEMBER APOSTOLAKIS: They don't know.

MR. SYDNOR: -- is that we are trying to -- one thing we are trying to do is make sure that all of our regulatory guidance, which quite often is targeted at specific aspects, fits together and covers the whole picture.

MR. SANTOS: Maybe, NRR, you can help me out. But basically we are trying to provide some more guidance to the reviewer, more visual guidance to the reviewer of everything is fitting together, the regulatory requirements for these highly integrated networks.

Right now, they have to go through all of the documents and try to piece the picture in their minds, and then do the review. So we are trying to provide them a starting point, and then see how the application fits in.

MEMBER APOSTOLAKIS: So you are not -- I mean, the way you describe it it looks to me like it is more like a block diagram.

MR. SANTOS: Yes.

MEMBER APOSTOLAKIS: Have you thought of the possibility of using some of the methodologies that people have proposed to model these things -- battery nets, dynamic flow graph methods -- that go one or two steps beyond the block diagram, and they are trying to show relationships, and then you can use those models to actually produce something regarding interactions and failures? Is that part of the thinking here, or is this --

MR. SANTOS: That is part of the thinking. We would want to start small. This is an in-house effort, small effort.

MEMBER APOSTOLAKIS: It's in-house.

MR. SANTOS: It's in-house. It's small. As we start developing the first go-round, and based on the successes we have, we can then decide with user feedback how far, and that's definitely part of the consideration of --

MEMBER APOSTOLAKIS: Anyway, this -- the words "generic abstract model," and then understanding what is happening, they seem to be a little contradictory, but we will wait and see. The purpose of this review, by the way, is not to comment on individual projects. I mean, we are just talking here.

MR. SANTOS: Sure.

MEMBER APOSTOLAKIS: But you will -- the purpose of this is really to see whether you are covering the areas appropriately, or you have -- but a few comments -- I mean, the committee cannot resist making comments.

VICE CHAIRMAN ABDEL-KHALIK: Well, I see

everybody seems to sort of shrink at the idea of something like this being used as a DAC. What is -- conceptually, is there anything conceptually wrong with you developing a conceptual model that can serve as a guide for DAC development in this area?

MR. SYDNOR: I am just hesitant to answer that question. That wasn't -- we did not get that feedback from NRO that -- as one of the potential uses for this. I understand your point. If we extended this -- you know, if the first -- if our first development of this model is well met, I mean, or well received by the offices, then there is a potential to extend it into that use or others. We just haven't made that decision yet, and that wasn't the user request that we received.

MEMBER APOSTOLAKIS: Well, the communication is an issue, right, Charlie?

MEMBER BROWN: Communications is a big issue.

MEMBER APOSTOLAKIS: I am surprised you are silent.

MEMBER BROWN: Well, this is different communications. Here they are talking about networks, and it depends on how -- if somebody has decided they are going to take the reaction protection system, and make it an integral part of a network, which is a distributed network, we would be insane to do that. You wanted blunt words; you would be insane to couple all of that staff inside of a distributed network.

That's not the way the designs are going today. Right now there is a separate -- because you can't control it. Stuff is all over the place. Your independence, your redundancy is toast, because you've got too many communicating paths.

But at some point you are going -- now, if you are talking about once you leave and you've got a central control station, you are going to -- there is a number of the -- ESBWR as an example, they've got a distributed network, the way they move data and commands around to get them down to the plant systems, or whatever. That's the network aspect.

The other ones are dedicated systems, you know, train by train by train. And they output information, but they don't -- into the network, but they aren't -- but they act independently of the network.

MEMBER APOSTOLAKIS: Well, I think the message I'm getting from this is that before you gentlemen go too far into the research -- because, again, this is not -- the purpose of this meeting is not to go deeply into each of the projects. But before you invest too much time in this, maybe we can have a subcommittee meeting on specific projects, in which case comments of this nature would be very appropriate and relevant.

MEMBER BROWN: Well, you would like to see some framework that they -- what they've got -- this is a very abstract discussion right now, because they can't even explain the framework of what they are looking for.

MEMBER APOSTOLAKIS: They admit that this is an exploratory piece of research.

MEMBER BROWN: Correct.

MEMBER APOSTOLAKIS: I don't want to discourage that --

MEMBER BROWN: They also admit this is an abstract framework, and that they are not sure what the pieces are they are even dealing with.

MR. SYDNOR: We have not developed that framework yet. That is --

MEMBER BROWN: They just say "networks," there is networks there. How do they work within the framework of what we are doing? Oh, okay. Let's -- I don't disagree with thinking about it, because if you look at it, the new plants are obviously going to be using -- once you exit the explicit systems, you are going to have this distributed network, and it is going to be doing a lot of things. And you have got to have some idea what you are going to do it, how it is going to operate.

One of the concerns when we were up at the -- where is Otto? Where is Otto when I need him the most?

MEMBER APOSTOLAKIS: Oh, there he is.

MEMBER BROWN: The Westinghouse simulator setup, and they had -- you know, they showed us the central control, you know, how their central control was set up. They got the networks there.

When you send a signal from that, how does it get deterministically down to an actuator? If you want to tell the plant to scram, do you have a wired switch, or do you put something into the network that goes down and tells the protection system to tell the thing to scram? How do you want to do that?

MEMBER APOSTOLAKIS: Is that part of this network work?

MEMBER BROWN: Well, that's how the signal gets from there down to the -- if you want to manually do it. They don't know that.

MEMBER APOSTOLAKIS: But when we say

"generic abstract model of plant-wide digital systems" --

MEMBER BROWN: "Digital systems" is a very generic term, I mean, not to coin a phrase.

MR. SYDNOR: We intend to include, you know, data flow issues for protection systems, yes.

MEMBER APOSTOLAKIS: So I guess, again, to wrap this up, it seems to me that before you really jump into it too far we should have a meeting.

MR. SANTOS: We agree with that comment. That's why we are starting --

MEMBER APOSTOLAKIS: Okay. Safety assessment of tool automated processes.

MR. SYDNOR: This is another new project. And unlike the one we just discussed, this one was requested by the user offices. We had input from both NRR and NRO, primarily because they are in the process of doing this on a case-by-case basis based on a specific license application where vendors or utilities are using automated tools as part of their digital I&C software engineering process.

There is a couple of specific examples. When we were at the subcommittee meeting there was a representative from AREVA who mentioned that they have some topical reports that they have submitted for some of their tools.

And so what we are going to be doing here is trying to see if we have adequate guidance, and, if we don't, try to create that and try to leverage standards that may be already in use internationally or otherwise to try to improve our regulatory guidance for our staff reviewers in this area. What do we need to be looking at when we critique these tools?

The third topic -- or the third topic in this programmatic area is --

MEMBER BROWN: Let me make one comment on that, just to make sure -- and correct me if I'm wrong. Part of the discussion on that one was vendors that are designing a digital I&C -- software-based systems want to use automated tools to validate their software.

Different ways to do that, you can either do line-by-line physical data code inspections, walk it through, have teams, or you can set up a program that runs the programs that says, "Oh, yes, we are independent with this. All of our responses are right. We get the right answers on everything." They'd like to do that, and they all have their own little in-house -- I think Bill Kemper phrased it best -- their own home-grown tool, which they think is the cat's meow, to coin a 1920s phrase.

Right now there is no validation, there is no benchmarking on any of those. And if somebody wants to believe the results, they can. But I wouldn't.

MEMBER APOSTOLAKIS: The tools themselves.

MEMBER BROWN: The tools themselves, and say they are adequately validated. That is the question they are getting from folks like NRO and NRR is: how do we respond? Is there a way to determine or validate these tools for use in this? I mean, it's certainly nice if you can do that, because validating software is very, very intensive, whether it's due to injection of signals, or whether it's due to some other -- you know, whatever the methodology is they're using.

It's probably -- this one is probably -- you know, this one is a little mushy. This one is a little bit more hard, you know, right now type issue that people are going to have to be dealing with.

MEMBER APOSTOLAKIS: Because it's a user need.

MEMBER BROWN: Yes.

MEMBER APOSTOLAKIS: Every time you have a user need, I think there is --

MEMBER BROWN: Yes. So that's what that means.

MEMBER APOSTOLAKIS: Okay.

MR. SYDNOR: Okay. The third topic area in this area is -- really, this is -- we currently have research ongoing with the University of Virginia where the Electrical Engineering Department there has developed a technique for -- fault injection methodology for testing and looking at default tolerance of an integrated digital system.

And by "integrated" I mean their test method looks at the physical system with the software application running on the system, so it is looking at fault tolerance under operational-like conditions. And they have developed some methodology for challenging the systems, developing a fault injection profile, and then using the results of that to draw some conclusions about how fault tolerant the system is.

We foresee a number of potential uses for this. One would potentially be to use it as an independent verification of the system reliability. And, in fact, University of Virginia has used that for some industries. The railroad industry has asked them to test a number of their digital control systems using this methodology.

And so we are test running that. We have -- they have finished a body of work where they tested a mock-up of the AREVA Teleperm system, and that is the one -- and then, when we presented to the subcommittee, we had a request from the subcommittee to present the results of that. So we will be scheduling the University of Virginia to come up and talk to the subcommittee about that.

We are moving on to look at a second digital platform. And, again, the goal is not so much -- it is testing the platforms, and so we are learning a little bit about the platforms themselves, but it is not a full-scale mock-up. And so, really, the goal of this research is to develop the methodology. And it is very promising thus far, and we have done some internal presentations of that work to the user offices and gotten some good feedback on that. And so this research will be continuing on.

One aspect of it -- there was some early on potential user trying to estimate the reliability of the system to develop a number that we could use for the system in a PRA model. We are deemphasizing that aspect of it, and really focusing more on the, you know, viability of the method for an independent assessment.

MEMBER APOSTOLAKIS: Now, this last bullet I think is inconsistent with what is in the plan we have. This is a result --

MR. SYDNOR: Based on feedback from the subcommittee.

MEMBER APOSTOLAKIS: Okay. But we are reviewing what is written in the plan. Okay. Not --we are not reviewing the slides.

Second, there was a subcommittee meeting -- or full committee, I guess, I don't remember -- several years ago where the university presented their work. I thought we had written a letter, but we didn't. But I'm sure the record -- the transcript exists someplace. It would be useful to go over it, because there were a lot of questions about what this approach can or cannot do. It has been a few years now. I don't remember when it was.

And the title "Benchmark Reliability Data," are you really producing reliability data? I don't think so. I think -- I mean, the best you can do here with a faulty injection is to gain some confidence that certain faults will not lead to bad results. So it's a matter of increasing your confidence in the performance of the software.

And, of course, if you find the fault, you fix it. So I'm not sure you are producing benchmark reliability data. Maybe you need a better title.

MR. SANTOS: Yes.

MEMBER APOSTOLAKIS: But the reliability estimates, I mean, stay away from it. That's not the way to do it.

MEMBER BROWN: Again, you've got to bear in mind this is a -- one of those aspects where people would like to be able to take a simulation-type model and have it --

MEMBER APOSTOLAKIS: Yes.

MEMBER BROWN: -- again, automated fault process where you go through -- the problem with that is it's dependent upon the intelligence, the smarts, the creativity, whatever you want to call it, the innovative thought processes of those who put the faults in. And the possibility of what happens when people start relying on these, they start believing that once they finish that everything is okay. And that is -- that's a hard spot.

And the point I would make with this type of fault, I can see some utility in it, because of what is going on with some of these systems we are seeing come in, because they no longer -- they are not independent anymore effectively. They are communicating loop to loop, train to train, into the program loops. I have made that comment.

Oconee does it one way, ESBWR does it another way. If you are going to -- and that is allowed. If you look at the interim staff guidance and stuff, they are saying, "If you're not going to do this, then you've got to be able to tell us why it's okay to do this." You've -- it's very, very hard to know, then, all the combinations of stuff that could go wrong via those communication paths, which -- when they go from A to all the other divisions simultaneously.

So, I mean, there is -- if you could really say this works, that would be a confidence builder. The question is whether you -- once you have breached that armor, that barrier of communication from channel to channel, you are into the mode of you've got to have confidence. You've covered everything that could possibly go in there and cause all four to burp at the same time. That hasn't been demonstrated in any of the discussions we have had in any of the meetings.

MEMBER APOSTOLAKIS: And it cannot be demonstrated, in my view. I mean, just another way of building confidence I guess.

MR. SANTOs: I just want to add that we recognize that, and this methodology will be just another tool in our toolkit, not to be misused.

MEMBER APOSTOLAKIS: Another thing you have to be careful, because I remember we had a whole litany of industries that have used this approach. In fact, I had a meeting on safety culture earlier with the staff. One thing they had there is that you have to make sure that people working in the nuclear business appreciate that it is a unique business.

So I don't know whether the railroad business has an ACRS -- has the level of scrutiny that, you know, your methods have to go through. So to say that railroads use it doesn't really do much to me. It is nice that somebody is using it, but, I mean, if you told me that maybe airliners use it, you know, FAA and all that, that would be a little more serious.

But anyway, I think we have the right level of understanding, as long as we don't overestimate here the value of this.

MR. SYDNOR: And you are going to -- very soon, as soon as we can schedule it with the subcommittee, you will hear some actual test results --

MEMBER APOSTOLAKIS: Yes, yes.

MR. SYDNOR: -- on a current platform that is being licensed.

MEMBER APOSTOLAKIS: And what conclusions you reach from those.

MR. SYDNOR: Exactly.

MEMBER APOSTOLAKIS: That's the thrust of the comments that Mr. Brown --

MR. SYDNOR: We'll be looking for your feedback --

MEMBER APOSTOLAKIS: -- was making.

MR. SYDNOR: -- specific feedback on that, and you can ask the detailed questions like that.

MEMBER APOSTOLAKIS: It's okay to put a few faults and see what comes out, but the conclusion is --

MEMBER BROWN: Yes, that's -- if you haven't figured it out, I'm very nervous about the lack of -- you know, the compromise of independence on that, because that is the prime protection against common cause -- whether it's common cause hardware failures, or whether it's common mode software failures. Independence is your primary mode of protection, no matter what you do. And as soon as you start communicating, you have lost that.

So now you are saying: how do we compensate? Now you are looking for, how many antibiotics can I pump into each train to make sure it doesn't get infected? I like that analogy. I hope that's on the transcript, so I can remember it.

MEMBER APOSTOLAKIS: All right. So we move on to nice, Greek names now.

MR. SYDNOR: The next area was a topic that was in the previous plan, but was not started. But we have recently written a statement of work for this, and we are going to be proceeding. And this area is going to look at both classic diagnostics and prognosis, the use of software-based, you know, tools to predict failures in both the plant and equipment, but this -- our scope of this will also include looking internally at the digital system, too, what diagnostics and prognosis might be built into a system to look at trying to predict failures of the digital system itself.

And this does not include, for instance, online calibration of transmitters, because that work has already been completed under the old research plan. And there is a published NUREG series that talks about the viable methods for that and how we would license an online monitoring system at a nuclear powerplant.

So this is going to look at the remaining issues, and it is just starting.

MEMBER APOSTOLAKIS: The main focus of all of these projects -- actual systems or -- when we say "digital I&C," what do we mean?

MR. SYDNOR: Primarily safety systems.

MEMBER APOSTOLAKIS: "Safety" meaning --

MEMBER BROWN: Reactor protection and safeguard system --

MEMBER APOSTOLAKIS: Actuation, scram, start --

MEMBER BROWN: Start the pumps.

MEMBER APOSTOLAKIS: -- startup, close --

MEMBER BROWN: Close the valves.

MEMBER APOSTOLAKIS: -- that kind of thing.

MEMBER BROWN: Cause the gravity drain system to actuate, whatever.

MEMBER APOSTOLAKIS: They are simpler than feedback and control, right?

MEMBER BROWN: Oh, absolutely. They are once-through, so --

MEMBER APOSTOLAKIS: Okay. Maybe the

problem -- okay. Okay, good.

MR. SYDNOR: We also retained or actually added a new research activity to look at modeling of digital systems. This is computer-based modeling, and the idea to continue this was based on -- we actually did a predecessor research activity where we simulated a -- it was based on the Oconee STAR system, which is an integrated control system, you know, kind of a first-generation digital system.

And we did develop a working model that you could interface with the trade plant model. It was not really a viable model. It was slow and hard to use. But it did prove -- it was kind of a proof of concept, and so, because of the needs in other areas, maybe modeling of these systems for PRA, things like that, we decided to retain this as a research topic, and take a look at modeling again under the new plan.

And the next area is fairly obvious -- digital system PRA. There was -- again, feedback from the user offices was to continue research in this area. The committee is well aware, and the committee has reviewed in detail the work that was done under -- by Brookhaven on traditional modeling.

There is published work under a series of NUREGs for -- Ohio State work looking at dynamic methods, and there was some excellent feedback from the subcommittee last year on where we need to go with looking at PRA methods for digital systems, the primary feedback being, take a step back and make sure you have -- you can actually develop the inputs you need for these methods and models.

But we did retain the topic. The Steering Committee also asked us to retain that, because there is -- because of the NRC's policy on risk-informed regulation. We are still trying to solve this issue. We don't have the answers right now, and the work to date, which is fairly extensive work, the work to date has not -- has not given us a viable method yet.

But that really leads us into the next topic area, which is probably the biggest new area in the research plan, and we are calling it analytical assessment of digital I&C systems. And this has a lot of different -- several different subprojects in it, and several of them are geared toward directly answering feedback and suggestions that we have received via staff requirements, memorandums, which have been, you know, an outcome of previous ACRS reviews, and other efforts.

And inventory and classification -- we are looking at starting that effort to help bound what are the nature of digital systems that we really need to be concerned with, instead of being concerned with a broad universal structure of digital I&C. We can probably bound what we are really concerned with by focusing on what will actually be used in nuclear safety applications, and so we are going to be doing that.

We are going to be trying to solve the issue we were talking about earlier, what are the systematic failures that we really need to be concerned with on these systems? What are the software failures? Trying to define those issues, come to agreement on them, and then those would be -- if we can answer those, they will be the building blocks of answering some of these other questions on, can we -- to what extent, and can we, model digital systems for PRAs?

The other office has also asked us while we're doing this to focus on -- there is currently three pre-approved safety platforms -- Westinghouse Common Q, the AREVA Teleperm, and the Invensys TRICON -- and they are asking us to focus on those as we go through and look at failure modes and effects analysis on these systems, as one of the tools that we will be looking at on trying to develop, what are the failure modes we are concerned with with these systems?

MEMBER BROWN: Now, those are the platforms themselves. It's like the CPU units on their circuit card, whatever it is, with all of their other interface -- you've got to -- the platform point, you've got to understand, is -- if those are used independently in each division -- they are black boxes -- you want to make sure they are as reliable as possible.

But from a big picture standpoint, they are just a box, as long as you're not sending stuff from someplace else into, and you are not sending stuff someplace else back out to the other program loops. So, I mean, you can -- you can treat these almost like analog systems, if you maintain the total independence of that platform from communications with any other platforms. If you don't maintain that independence, then you've got another level of problem.

All I'm trying to do is I'm not saying yes, no, or whatever. I'm just saying to put that in perspective, when they talk about TRICON or what's -- MELTAC or -- and what?

MR. SANTOS: TSS?

MEMBER BROWN: I don't know, whatever

these things are -- the AREVA Teleperm -- that's all they are. If you look at an old analog system, you would see a box called "amplifier." Take the amp out and put CPU in, and that's what that is, as long as you didn't change any of the rest of it. It's a box. If it fails, it fails, that channel goes down.

So that's what -- but you want it to be reliable, and there is a lot of complexity in there. So you want to make sure the housekeeping stuff, and this and that, are all going to perform their functions. So that's kind of -- am I not phrasing that right, gentlemen, relative to what -- you are all trying to make sure those are reliable platforms.

MR. SANTOS: Yes.

MEMBER BROWN: Okay. Thank you. That was a good guess. I like that.

MEMBER STETKAR: Who is using TRICON?

MR. SANTOS: Diablo Canyon is planning --

MEMBER BROWN: Yes. Somebody has got three different platforms or --

MR. SANTOS: TRICON from Invensys is Diablo Canyon, AREVA Teleperm XS is Oconee.

MEMBER BROWN: Yes, I thought one of the projects we were looking at that -- was using three different platforms. They had TRICON, they had

MELTAC --

MEMBER STETKAR: MELTAC was APWR. TRICON was sort of a candidate for an ESBWR.

MEMBER BROWN: Yes, I might have them mixed up. I'm sorry. Is it -- that's irrelevant to this discussion. We can go on.

George, you can -- oh, I'm sorry. He's distracted right now.

MEMBER APOSTOLAKIS: Yes. Well --

MEMBER BROWN: You can go on, if you would so desire. I interrupted, so you can tell him to just keep going.

MR. SYDNOR: Okay. We are going to move on to the next major program area, which is security aspects of digital systems. And this area has three topics that we are -- actually, they are all underway, so these are all continuations from what is in the current plan. And in several of them, significant progress has been made, so we will be hopefully wrapping these up in the next year.

The first one is security of digital platforms, and in this one we have had -- we have Sandia National Laboratories helping us do cyber vulnerability assessments on these same platforms that I've mentioned. For the Westinghouse Common Q one, we just completed some work where a utility volunteered or donated their mock-up of the Common Q application for Sandia to come onsite and actually do some cyber vulnerability assessments. So we have some reports of that.

We have delivered those reports to the user offices, and those reports cover potential cyber vulnerabilities that were found by Sandia. Not only that, but they give mitigation suggestions for --

MEMBER APOSTOLAKIS: Now, we have a subcommittee scheduled on this cyber security issue soon, right? A lot of this stuff will be presented then, or this is just for the future?

MR. SYDNOR: We did discuss having these on the agenda, but that was such a full agenda, and there is so much detail in these that I am not sure we could, you know, everything else we needed to do that day. I know the Reg Guide is in that schedule also.

But we could schedule that. We have results on several platforms already, and we are getting ready to start the third platform.

MEMBER BROWN: I won't be here, George.

MEMBER APOSTOLAKIS: Huh?

MEMBER BROWN: I will not be here.

MEMBER APOSTOLAKIS: The 23rd?

MEMBER BROWN: Yes, I am still flying back.

MR. SYDNOR: Right now, the reports on these are considered OUO security-related, because they actually -- the reports have a significant detail on how Sandia modified code --

MEMBER APOSTOLAKIS: You are suggesting we schedule another subcommittee --

MR. SYDNOR: Potentially.

MEMBER APOSTOLAKIS: -- to talk about these things when Mr. Brown will be back, and we'll go to a secure room.

MR. SYDNOR: Right.

MR. SANTOS: And we will turn the air conditioner off.

MEMBER APOSTOLAKIS: How do you transcribe that?

(Laughter.)

MEMBER BROWN: Number 2 pencils and yellow legal pads.

MEMBER APOSTOLAKIS: Okay. Let's move on. We are running behind, and the chair will get upset.

MR. SYDNOR: The first topic, as I mentioned, is actually looking at vendor platforms. The second area is more of an investigation of best practices and standards that perhaps the nuclear utility needs to adapt -- I mean, nuclear industry needs to adapt.

So we have Sandia looking at wired networks, and Oak Ridge has been doing some -- a series of look-ahead work on wireless networks, you know, what limitations should be placed on those in a nuclear powerplant environment, both from just application of the network, but also this -- we are now having them look at what security mitigations would need to be in place, if in fact you are going to use a wireless network.

MEMBER BROWN: Why are you all doing that? I mean, why do we keep making it harder and harder? Is this a job security issue? I mean, why are we going to even consider having all of our data broadcast throughout the territory?

MR. SYDNOR: No. Right now, there is no plan or -- you know, I can't envision NRC improving --

MEMBER BROWN: I am just talking to you theoretically relative to a regulation regulator viewpoint of what you want people to do. I mean, this -- it just boggles my mind that we just -- you want to make it more and more complex, and make it more and more difficult to protect your data. I mean, here

I've got a vault full of -- a mine full of gold, and instead of having doors and locks and everything, I just have an open window, so people can just walk in, check out the gold, see whether they want any, and leave.

MR. SYDNOR: Are you talking about the -- just specifically, I thought you were just talking specifically the wireless. That was actually --

MEMBER BROWN: I'm not saying I like wired networks either, but at least they're more palatable than wireless --

MR. SYDNOR: In the current research plan as, you know, anticipatory research, you know, obviously the NRC is not doing research and development to try to sell the use of wireless networks in nuclear powerplants.

MEMBER BROWN: Well, I don't anticipate you are selling, but if somebody proposes it --

MR. SYDNOR: In fact --

MEMBER APOSTOLAKIS: Is anybody proposing it?

MR. SYDNOR: Not for safety systems. But, in fact, wireless networks are -- you know, wireless is used in nuclear powerplants for maintenance purposes and security operations, use in walkietalkies.

MR. SANTOS: At a minimum, we should do the anticipatory research, so when such an application comes we have the basis to tell them yes or no.

MEMBER ARMIJO: Skip the research and say no is --

(Laughter.)

MEMBER MAYNARD: Probably the research program would be very short on this.

MEMBER BROWN: I made that comment in the subcommittee meeting and got ignored.

MEMBER APOSTOLAKIS: I don't think the staff can issue a --

MEMBER BROWN: This is unusual.

MEMBER APOSTOLAKIS: -- while -- I mean, it's impossible unless they have damn good reasons, and I don't think they have them. So the fact that they will do some anticipatory research --

MEMBER BROWN: Well, no, they can do that. I'm just -- it's just -- I'm trying to send a message subtlely.

(Laughter.)

MR. SYDNOR: Received.

MEMBER APOSTOLAKIS: I take it you like the word.

(Laughter.)

MR. SYDNOR: Message received.

MEMBER APOSTOLAKIS: It was too subtle for us. Okay. Thank you.

Well, actually, that's good, though. It's important for you to get a sense of how members feel about certain things.

MEMBER APOSTOLAKIS: Where are you now, security assessment or --

MR. SYDNOR: The third topic area is a -- essentially, we have been revisiting some research that was done in the early 1980s, and there was a NUREG issued at that time that looked at potential EMP effects from, you know, high-level nuclear detonation on nuclear powerplants. And that old NUREG is out there, and the conclusions from that NUREG were that although the plants likely would shut down mainly because the grid is most likely going to shut down --

MEMBER APOSTOLAKIS: Let me understand this. How easy is it to get those EM/RF emitting weapons? I'll tell you why, because this is the practice of, you know, you figure out a threat, and then you assume it's there.

Now, you guys do something to make sure that the consequences are not severe. And that bothers me. I mean, that's not risk-informed at all. I mean, the practice of assuming some crazy idea and then forcing the licensee to do something about it, so --

MR. SYDNOR: But we haven't made --

MEMBER APOSTOLAKIS: -- how easy is it?

MR. SYDNOR: We have not made that decision yet. This is, again, anticipatory research.

MEMBER POWERS: It's very easy.

MEMBER APOSTOLAKIS: Very easy?

MEMBER POWERS: I mean, if you've got a nuclear device, it's going to give you an EM pulse.

MEMBER APOSTOLAKIS: Do you understand what my concern is? I mean, assuming no sort of hazards, and then saying, "Now you do something about it," I don't think that is a rational way of doing business.

MR. SYDNOR: What our new research is doing is revisiting -- a number of things have changed. Obviously, when the earlier study was done, analog systems, for control systems and safety systems, and safe shutdown systems, now we have digital systems, and so the new study is looking at the potential effects on digital systems. Are they different than what we assumed in the earlier study?

And also, we are looking at, you know, potential new threats, high radio frequency threats.

And the outcome of the research has some interesting results that we will -- you know, we will be presenting to management at the NRC to see if this is an area where we need to do something as far as, you know, is it a viable threat that we have to in fact regulate against.

So those decisions haven't been made. This is just research looking in the potential for effects on the plants themselves. And we are just about finished this research. Sandia has looked at both the new threat levels and things that could occur now that weren't even part of the earlier study, and so -- but we will be providing our recommendations there and findings to NRC management to make a determination of where this fits in regulatory space.

MEMBER BROWN: I was going to say, if you want to solve this problem, you go back to vacuum tubes and magnetic amplifiers and make -- they are resistant to EMP.

MEMBER SHACK: No, take away George's cell phone. That's --

(Laughter.)

MR. SYDNOR: Moving on, the next program

area is really supporting advanced nuclear reactors, and this is not new reactors, this is really looking at some of the advanced designs.

Primarily, the current new research efforts, which we have just initiated, are looking at NGNP, you know, high-temperature gas reactor, and some new aspects of that both in instrumentation and control, where it is -- really, the research is -- we are not going to be actually doing the R&D so much as following R&D efforts that being -- that have been done by other countries or being done by others, so that the NRC -- we can pull that knowledge in-house and be ready when and if we get a license application from -- for a DOE prototype or for one of the other advanced reactors.

So we have two research topics in that area.

The next program area is one that we have had -- we continue to have in each plant, and we are calling it knowledge management, and some things we do in this area, these are just broader -- not specific research areas, but just some broad things we do to stay in touch across the whole state of the art of digital I&C.

The first one we have had ongoing where we

-- every three to five years or two to three years we take a look at state-of-the-art and emerging technologies. Are there new things that are being proposed or unique to digital I&C that we need to in fact create a research topic, an anticipatory research topic to stay out in front of? And so that is something we do on a frequent basis.

Collaborative and cooperative research, we have a number of efforts ongoing here. We talked with the subcommittee about our newly-signed memorandum of understanding with EPRI to do some collaborative research with them in this area where it makes sense. We have had ongoing international collaborative efforts with OECD, NEA.

The COMPSIS is an operational experience-based effort that we are still participating in. The Halden Reactor project has a number of digital I&C research topics, and through our contributions of funding for Halden we are able to influence their research plan, and we have into to their research plan.

A new thing we are doing actually using our new senior technical advisors that we brought on board is trying to reach out to other -- work that is being done in other federal agencies.

One specific example that is mentioned is the networking and information technology research and development, and that is under the White House Office of Science and Technology, the National Coordinating Office, and they are looking at research on high confidence software and systems. And so certainly some of the research they are doing there may bear fruit and information that we would be interested in.

And so we have set up some collaborative efforts with them to stay in tune with what they are doing, and maybe even influence their research and development plans.

MEMBER ARMIJO: Do you have any kind of cooperation with NASA? It would seem that they have similar challenges with things like space stations, space shuttle, very complex systems. And these things are in service and they -- have they made any progress that the NRC could benefit from?

MR. SANTOS: The answer is, yes, we have also a memorandum of understanding with NASA, and we will also be participating in collaborations on digital I&C. We also make contact with the JPL to take a look at some of their data and collaborations, also attending their V&V processes, efforts, and centers, to try to learn from space shuttle, from the constellation program.

So they are being very collaborative. And we value that collaboration NASA, and we envision to continue.

MEMBER ARMIJO: Great. Thank you.

MR. SYDNOR: Also, in the area of knowledge management, we have ongoing efforts to -- where we participate in standards development, both IEEE standards and things like that. But we are really looking at a new effort here on trying harmonization with international standards, specifically IEC standards.

And so we are going to be kind of reinvigorating this area, again using our senior technical advisors where we have some outreach to try to harmonize IEEE standards with IEC standards. And that has obviously become a greater need through the new reactor program, where we are using a lot of international designs in those reactor designs.

The last -- not the last area, but organization of regulatory guidance. This was a request that we got from the user offices to add this to the research plan. And, really, what we are looking at is trying to improve the -- or come up with a tool that helps digital I&C license reviewers understand the very complex regulatory structure, regulatory guide structure that we have, where in a lot of cases things have been developed as individual entities, but understanding the whole big picture of how it all comes together again, and understanding all of the things you need to verify as you go through a license review.

So this is kind of a -- you might say developing an in-house tool, a request that we have had there.

And a final area in this -- or final topic in this area is operating experience analysis. And as part of the last Digital I&C Subcommittee meeting, there was actually I think about a day and a half of discussion in this area with EPRI and the NRC staff. And so we are going to be continuing to follow this effort.

There was an earlier question I think in this area. We have been for several years using Oak Ridge to try to go out and find data from non-nuclear industries and look at it and analyze it and see how we can apply it to the nuclear area.

Mixed results on that. Our latest attempt that they are still working -- and we hope to get a report probably within the next three to four months

-- is looking at -- we went out and actually purchased some of the failure databases that are available from other industries, and we wanted to help look at those.

And what do they tell us about failure modes? What are the failure modes that other industries have discovered and been concerned about? And can we learn from those?

And so we are still doing some of that work. We are obviously still interested in capturing operational experience on digital systems. We are really -- the industry is really just getting started on it. You may say 10 to 15 years they have been -- if you count the non-safety systems, they have been on a learning curve with operational experience.

But the safety systems and their learning curve there is really just beginning. And so we want to also use this effort to help us set up a structure where we may be able to capture that data for potential future use in PRA work and things like that.

So there are several different aspects of this. And, again, also we are participating in the international effort with COMPSIS to try to get some operational experience from the international plants for digital I&C events.

MEMBER APOSTOLAKIS: Is that ongoing now?

You have already -- is there an OECD or some organization, a group of people who do that?

MR. SYDNOR: Yes. COMPSIS is -- it's sponsored by OECD, NEA. There is about 12 countries that are still participating in it. The actual database is run by the Halden Reactor project. I am trying to reinvigorate it by putting more of our failure data into the system. But we have been told by the representatives of other countries at the Steering Committee meetings that they have -- their manpower limitations, that they have a number of events that they haven't entered into that database.

So the number of events there is very limited, it's very -- there are some interesting events in there. But can you draw conclusions from it? I mean, you heard the EPRI reports where they were looking at about 300 events, and even that data was limited when you actually got down to safety systems. This is even more limited currently.

MEMBER APOSTOLAKIS: Yes.

MR. SYDNOR: And whether it will be a viable entity four or five years from now I think remains to be seen. The other countries need to participate.

MEMBER BROWN: The root cause of the

information they get is a problem with making the information usable. If something happened, if you don't know the specifics of why, it is very difficult to do.

I ran a project like this where we took every incident report we had out of the naval nuclear stuff, and I came to the conclusion, which were all failures, probably only about 20 percent of the data is probably correct, where you actually get root cause information.

If you take it with that aspect and you just put it all in there with that idea, then you can kind of use it for trending-type information. But it's for specific stuff; that's much harder to do.

MR. SYDNOR: And that's the same lesson we learned looking at non-nuclear data, that we were able to get from other industries is that, actually, the nuclear industry is pretty good at root cause compared to other industry and documenting it through INPO database and things like that.

The last program area is really -- I could call it a catch-all. It is really a carryover from projects from the existing plan that were not started yet. Actually, in the first area, electromagnetic compatibility, actually a fair amount of work was done that looked at what testing and what requirements should be imposed on digital systems for EMI and RFI type limits.

And there is still some -- there is one specific test limits that the industry is asking us to go back and look at, because they believe that our test criteria are overly conservative. And there are some potentially -- this is actually an area where we are looking at some potential collaboration with EPRI to try to come to resolution of that one.

So that is not a major research effort so much as it is is just trying to resolve one issue that is still hanging on.

The second topic --

MEMBER BROWN: Before you leave that one, I had a question on it -- a comment on it. They think they are overly conservative, because they don't pass and they have got to go fix it. This is a standard industry-wide when it comes to testing for EMI.

It is difficult if you use the standards, but EMI can bullocks up your systems very easily. I had several instances where EMI actually caused multiple things to happen, neither of which we really wanted to happen. So, and we had passed -- we had actually passed the EMI tests that were -- the Navy

EMI tests, which are fairly rigorous.

So it's very unpredictable, but you want to test. So I'm a little skeptical about how far you back off or relax on this stuff. If you don't want to introduce --

MR. SYDNOR: The industry issue is not -- it's just one specific criteria out of probably thousands in there that --

MEMBER BROWN: I'm not objecting to looking at it. If something is truly -- you know, doesn't contribute, that's fine. But it's --

MR. SYDNOR: The limits that we are currently imposing through our Reg Guide exceed the industry standards, and those limits were based on some testing that was actually done in nuclear powerplants, and --

MEMBER BROWN: The industry standards were, or yours?

MR. SYDNOR: Pardon me?

MEMBER BROWN: Yours were based on testing in nuclear powerplants, or the industry's?

MR. SYDNOR: The Reg Guide standards. And the testing -- EPRI and the industry are questioning how that test data was interpreted. So we haven't agreed with that yet, but we are willing to look at it.

MEMBER BROWN: All right.

MR. SYDNOR: The next topic area is looking at basic operating systems that are used in digital CPUs. And so this one really -- it was an area that actually we were proposing to drop out of the new plan, but we had a request from one of the user offices to go back and look at that and maybe look at research there.

And the thing is, their issue is that when they review these designs that are submitted they are not sure they know all of the questions that -- the best questions they should be asking about how the basic operating system controls the digital platform. And do we have all of our -- adequate regulatory guidance and adequate knowledge for the staff to ask the right questions? And so they want us to explore that aspect of it.

And the final carryover topic, there was -- again, this was one where we are really looking at actual electrical power distribution effects on digital systems, and there has been plenty of evidence of -- through past blackouts and degraded grid issues to know that plants do see these events, although thank God they are not, you know, daily or annual events, but when they occur they are pretty severe.

And so do we understand how -- maybe we do understand how an individual digital system -- but, again, do we understand how a -- you know, power supply fluctuations across a network or a highly integrated design, what effect will that have? And so this is hoping to take a look at that.

So that is a high-level summary of all of the topic areas in the plan we are proposing. We made the plan publicly available. I think Dan already mentioned that we still have not received any significant public comments, and we really don't anticipate significant -- any more significant internal comments, because we had a -- you know, an extended, detailed review session down at the working level, with extensive comments from the user officers that we have replied to, and they have already seen our responses.

So our plan is -- incorporates some ACRS comments. We had some good comments from the subcommittee, which we will be incorporating in the plan. George mentioned a couple of those in the discussion today. And so we will be incorporating those, and then going into formal concurrence with the office directors.

And so our goal is to have the plan issued by the end of the year, end of the calendar year.

Dan, was there anything you wanted to mention about this MOU? We talked about it briefly.

MR. SANTOS: No. Unless the members have any questions.

MEMBER APOSTOLAKIS: Do we?

(No response.)

The members are happy.

MR. SYDNOR: So, in summary, although we might change the word, we are looking for --

MR. SANTOS: A Greek word.

MR. SYDNOR: -- ACRS agreement, approval, endorsement, that we have -- that the plan has the right topic levels, and that we haven't missed any major issues.

MEMBER APOSTOLAKIS: Yes.

MR. SYDNOR: Obviously, we will continue to work and present research results to --

MEMBER APOSTOLAKIS: So you are really looking forward to working with us.

(Laughter.)

MR. SYDNOR: Yes, we are.

MEMBER MAYNARD: I do have a couple of quick questions.

MEMBER APOSTOLAKIS: Sure, Otto.

MEMBER MAYNARD: One is, how much of this work do you anticipate being done in-house versus being outsourced to a lab or a university or whatever?

MR. SYDNOR: I would say the majority of our work -- if you ask me put a percent on that, I'll have to think on that.

MEMBER MAYNARD: Just rough idea.

MR. SYDNOR: The majority of it is outsourced to DOE labs.

MEMBER APOSTOLAKIS: Any other questions?

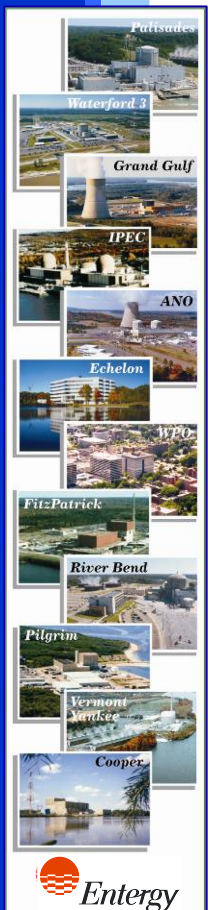
(No response.)

Okay. Thank you very much for the presentation. And back to you, Mr. Chairman. Wow, 10 minutes early.

CHAIRMAN BONACA: Let's take a break until five of 5:00.

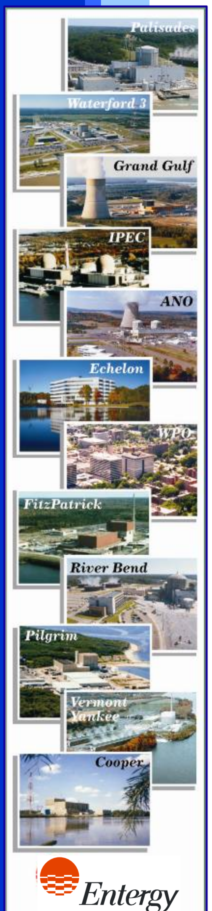
(Whereupon, at 4:50 p.m., the proceedings in the foregoing matter went off the record.)

Indian Point Energy Center



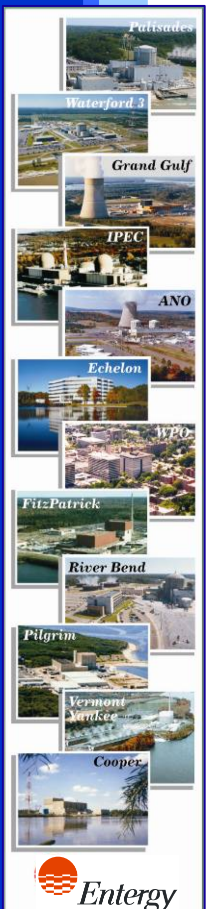
ACRS License Renewal Committee Meeting
September 10, 2009

Indian Point Energy Center Personnel in Attendance

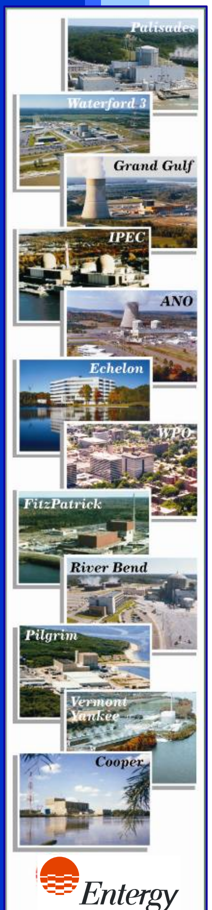


Joe Pollock	Vice President, Site – IP
Fred Dacimo	Vice President, License Renewal – IP
Pat Conroy	Director, Nuclear Safety Assurance - IP
Don Mayer	Director, Emergency Planning
Garry Young	Director, Business Development
Tom Orlando	Director, Engineering – IP
Bob Walpole	Manager, Licensing – IP
Mike Tesoriero	Manager, Programs & Components – IP
Tom McCaffrey	Manager, Design Engineering
John Curry	Project Manager, License Renewal – IP
Mike Stroud	Project Manager, License Renewal
Alan Cox	Technical Manager, License Renewal
Rich Drake	Supervisor, Civil / Structural Engineering
Nelson Azevedo	Supervisor, Code Programs

Background

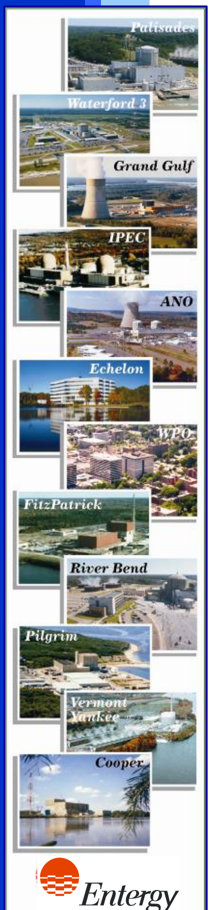

Palisades
Waterford 3
Grand Gulf
IPEC
ANO
Echelon
WPO
FitzPatrick
River Bend
Pilgrim
Vermont Yankee
Cooper
Entergy

ACRS Items of Interest



- Containment Penetration Cooling System
- Exterior Containment Concrete Monitoring
- IP2 Containment Liner
- IP2 Refueling Cavity Leakage
- IP2 Spent Fuel Pool Leak Plume

Containment Penetration Cooling System

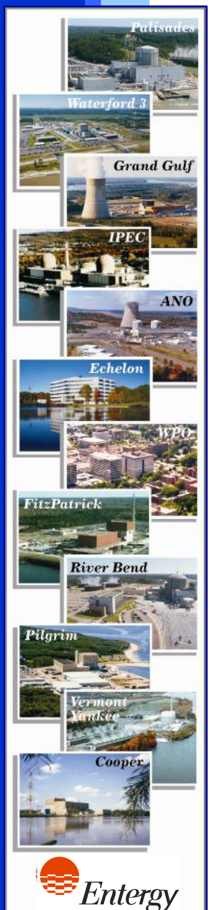


ACRS Questions

Did the analysis look at no flow, in other words, blockage of those cooling channel paths such that there was no convective heat transfer from the concrete?

If those cooling channels became plugged or fouled such that you had no air passage through there or substantially reduced air passage, regardless of the status of the blowers, would you still reach only a maximum of 200 degrees Fahrenheit?

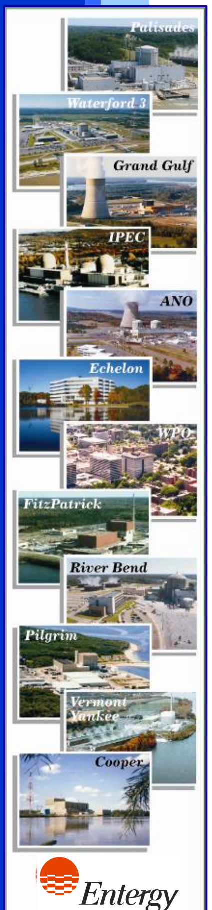
Containment Penetration Cooling System



Response

- Calculations were performed assuming no flow conditions which indicate temperature would exceed 200 degrees.

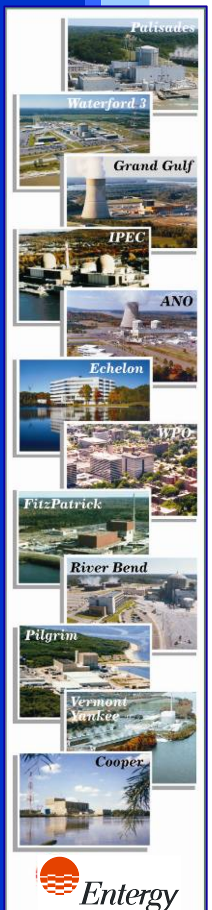
- Design simplicity and operating practices assure high system reliability.



Containment Penetration Cooling System

- Operators perform daily rounds.
- Operating procedures provide corrective actions based on instrument readings, including cleaning out penetrations, and replacing filters and silencers.
- Plant operating experience indicates that system is properly managed and is reliable.
- Concrete properties would not degrade below 300 degrees F.

Exterior Containment Concrete Monitoring

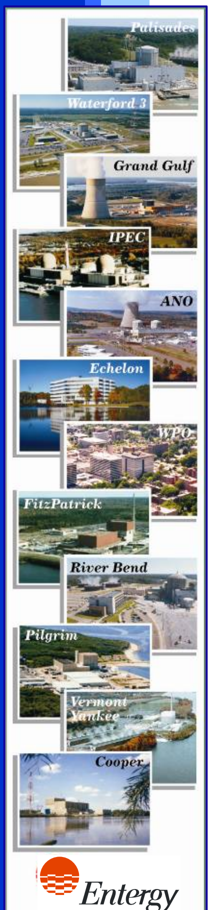


ACRS requested more information on IPEC containment concrete conditions.

Response:

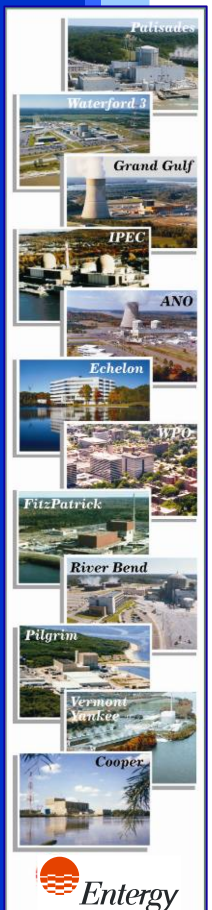
The IPEC concrete containments are monitored by the ISI IWL Program.

Exterior Containment Concrete Monitoring



- Isolated areas of surface degradation exist at some Cadweld rebar joints and scaffolding attachment points used during construction.
  - Documented in initial baseline inspections in 1995.
- Areas are monitored and have shown no structural impact to containment concrete.
- 41 locations at IP2 and 7 locations at IP3
- Locations are being coated.

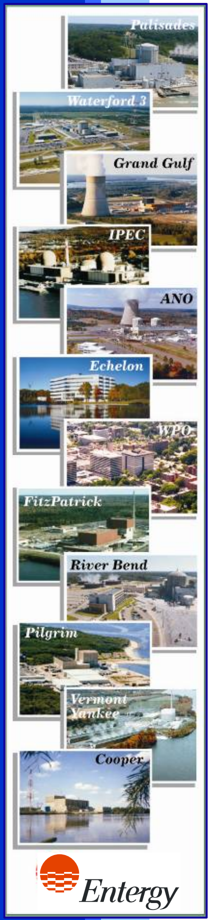
ILRT Results

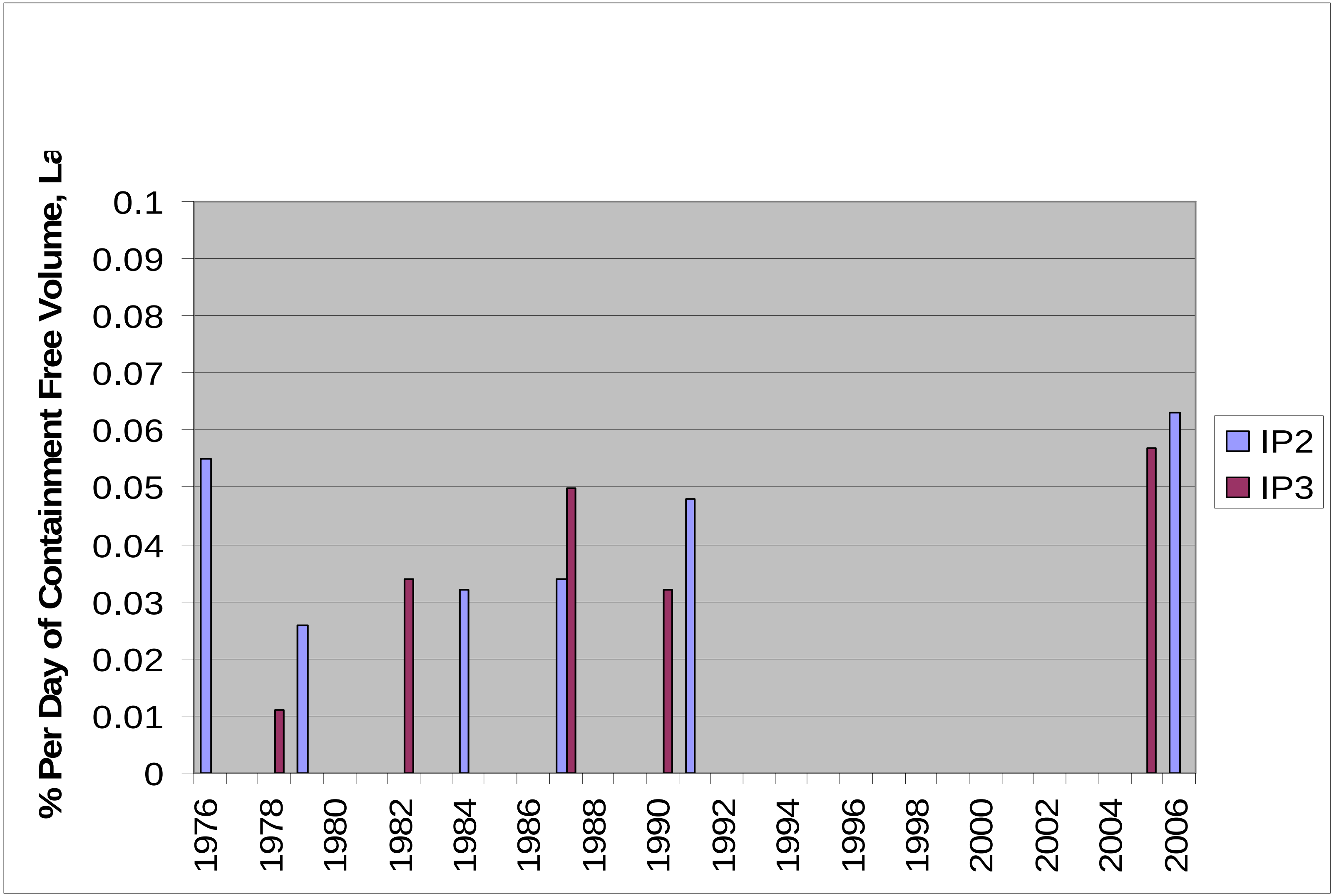


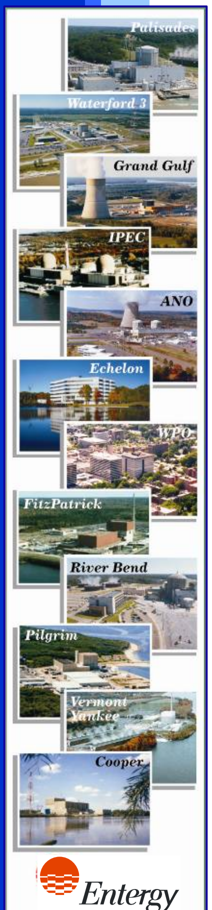
- Past ILRT results all below requirement of 0.075% of free volume per day.

- No unexplained changes in ILRT leak rates.

ILRT Results







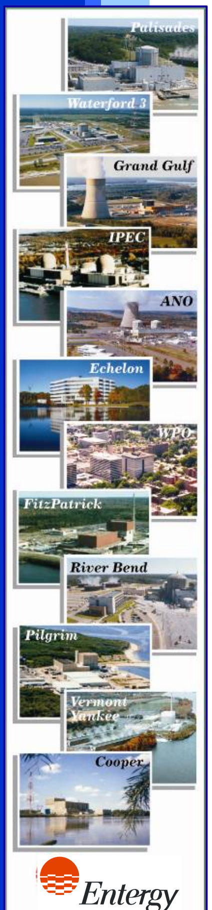
Exterior Containment Concrete Monitoring

Conclusion

The results of all ILRTs for both Units 2 and 3 have been satisfactory.

Visual inspections of the containment structures were performed with satisfactory results.

IP2 Containment Liner

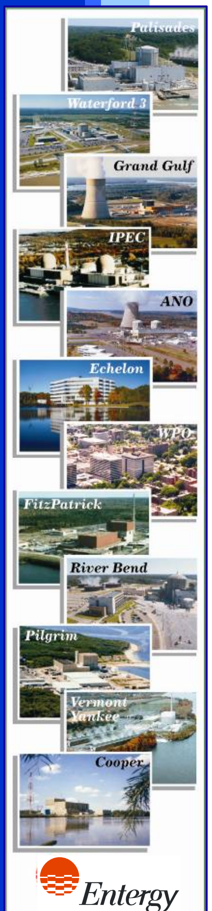


ACRS requested more information on IP2 containment liner deformation and concrete conditions.

Response:

A feedwater line leak in 1973 caused hot steam/water to impinge on the IP2 uninsulated portion of the containment liner causing a deformation of the liner in the vicinity of the piping (i.e., a bulge, approximately 5/8 inch and 2 feet wide running horizontally intermittently around containment for 60 feet).

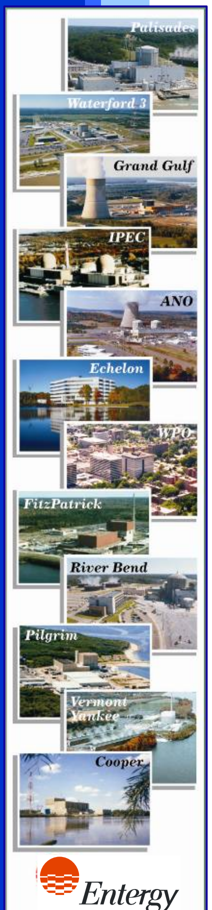
IP2 Containment Liner



- An evaluation of the steam/water mixture, that impinged on the liner, concluded that concrete temperature was below 300°F, the containment design temperature; therefore no damage to the concrete was expected.

- ILRTs and magnetic particle inspections of the liner and weld channel testing demonstrated liner integrity and that there was no loss or degradation of containment integrity.

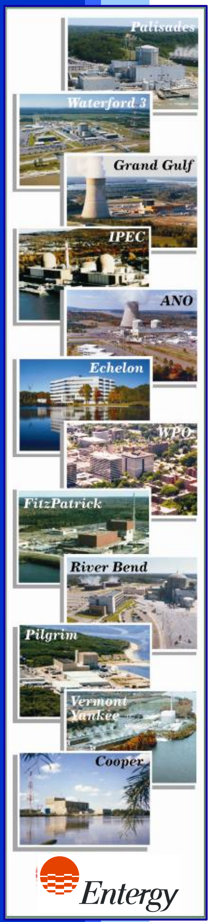
IP2 Containment Liner



- Ultrasonic inspection showed that 9 of 28 L-shaped studs in the bulged area were broken.

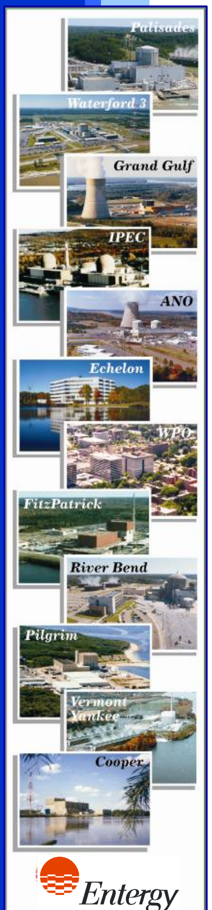
- These L-shaped studs are imbedded in the concrete and overlap rebar. Design of the ½ inch diameter studs is such that the stud would break well before containment concrete damage would occur.

IP2 Containment Liner



- Insulation was installed over the liner including the area of the bulge to preclude exposure again.
- An inspection of the bulged liner behind the insulation will be performed before the period of extended operation.

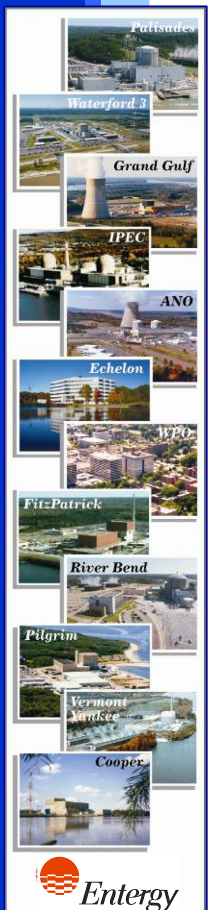
IP2 Containment Liner



Conclusion

- The 1973 feedwater line leak event did not adversely affect the containment liner and concrete condition.

IP2 Refueling Cavity Leakage



ACRS requested information about the safety significance of the leak and better figures to show the flow paths.

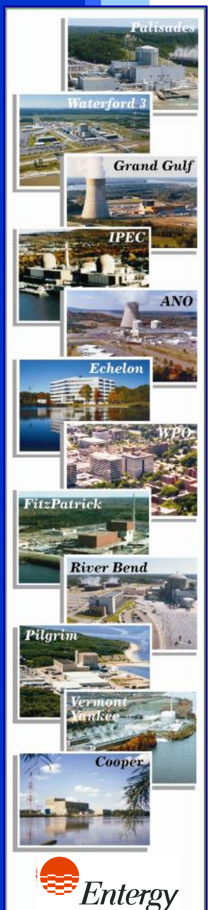
Response:

Refueling cavity leakage has no safety significance.

Leakage occurs only during approximately two-week period while the canal is filled during refueling outages once every two years.

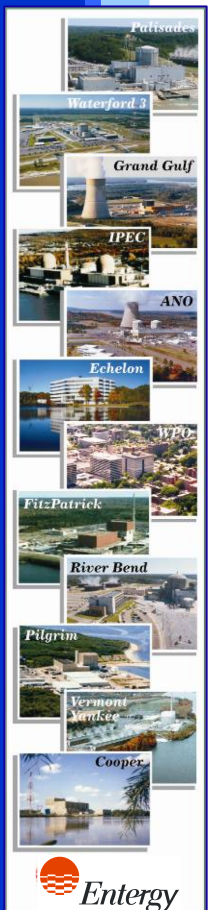
Industry experience, as confirmed by recent EPRI Report No. 1019168, supports the conclusion that degradation of the reinforcing steel and concrete is negligible.

IP2 Refueling Cavity Leakage



- Leak location
  - The refueling cavity begins to leak when the cavity has been filled to between 80’ and 85’.
  - Leakage occurs from three primary areas.
  - Leakage is collected in sump and pumped to liquid radwaste processing system

IP2 Refueling Cavity Leakage

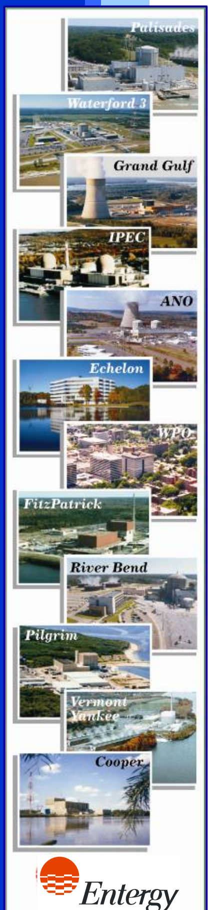


Inspections and Evaluations

- Evaluated on several occasions with the conclusion that leakage had negligible impact on structural integrity of the refueling cavity walls and adjoining structures.

- Previous inspections – included core samples removed from the refueling cavity wall in 1993.

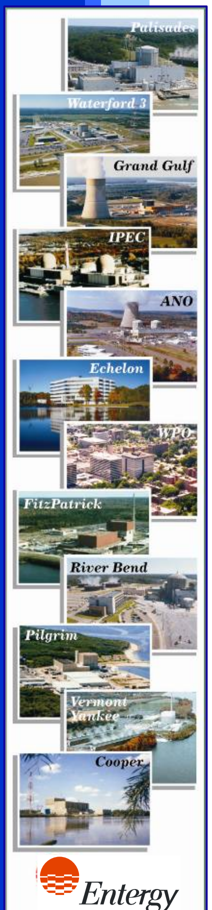
IP2 Refueling Cavity Leakage

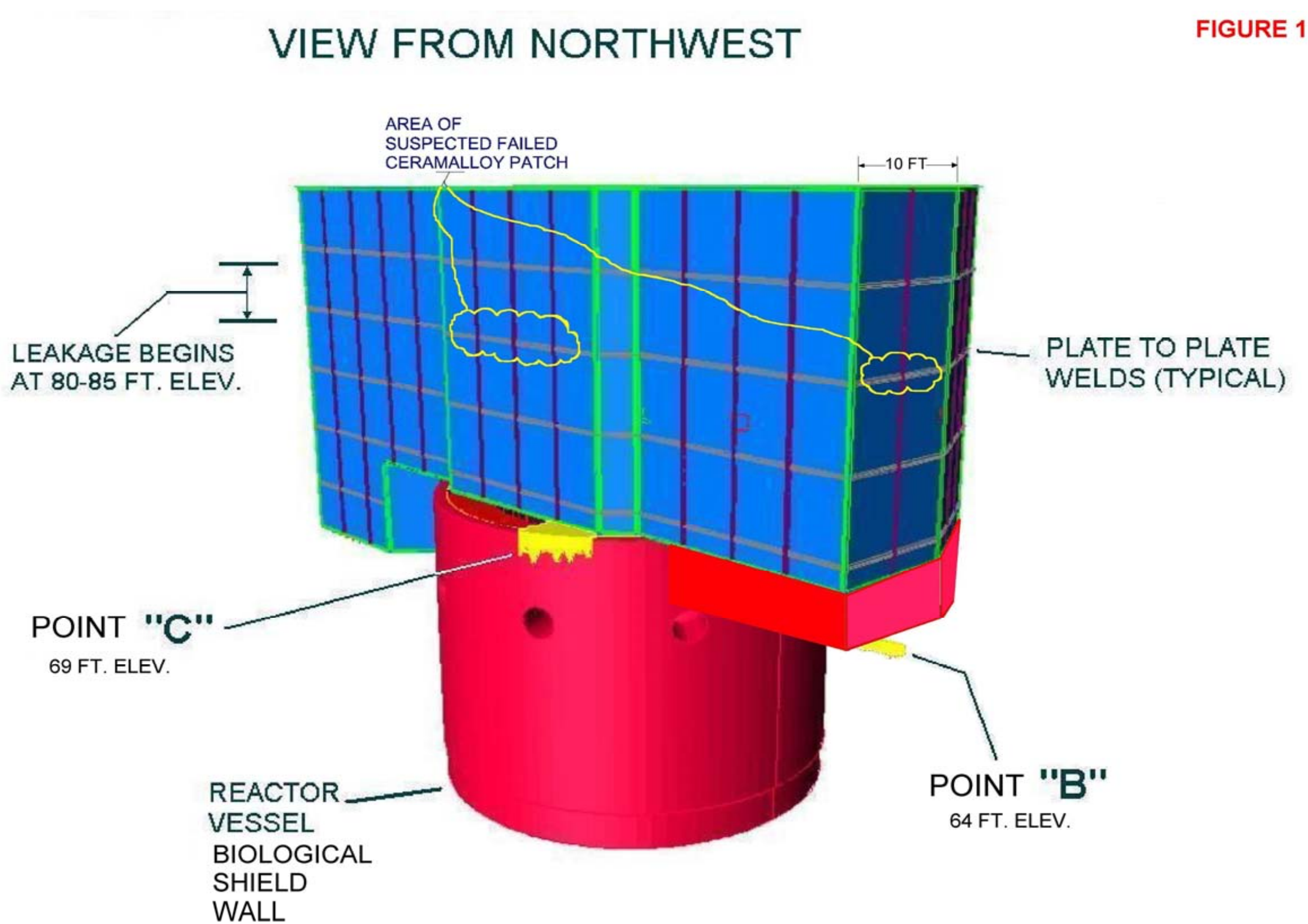


Future Plans

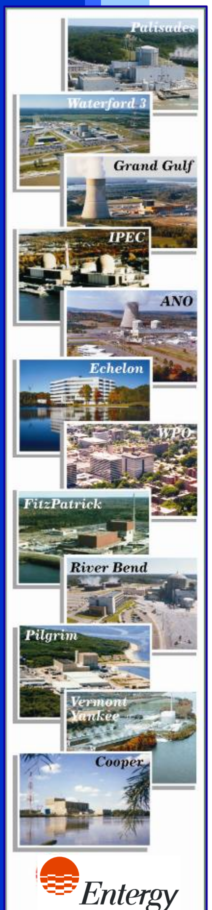
- Inspection prior to the period of extended operation will be performed to re-confirm no long term degradation (planned for 2010).
  - Rebar inspections including core bore samples
  - License renewal commitment
- Cavity liner repair activities planned for the subsequent refueling outages
- If a solution to the leakage is not achieved, IPEC will perform additional core samples and reinforcing steel inspections prior to the end of the first ten years of the PEO.

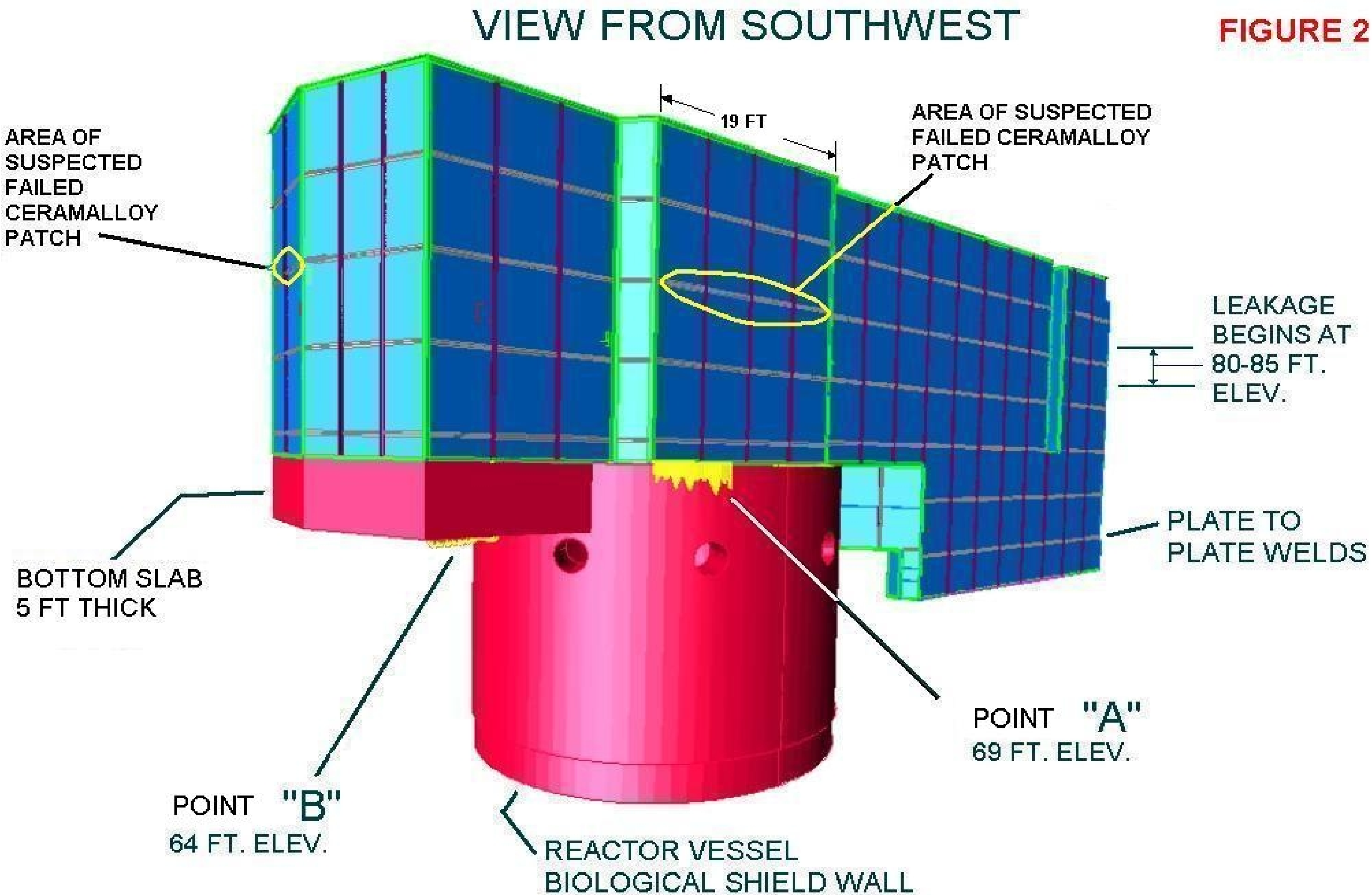
IP2 Refueling Cavity



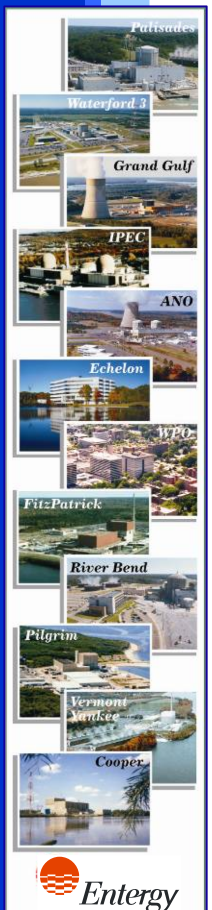


IP2 Refueling Cavity



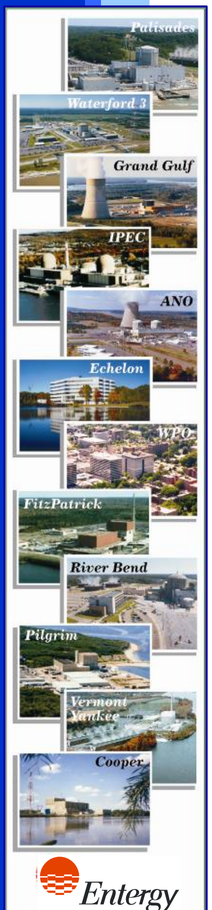


IP2 Spent Fuel Pool Leak Plume



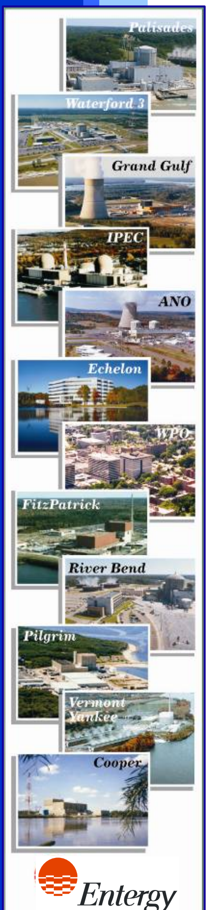
ACRS asked the applicant to bring more detailed hydrologic plume data for the IP2 spent fuel pool.

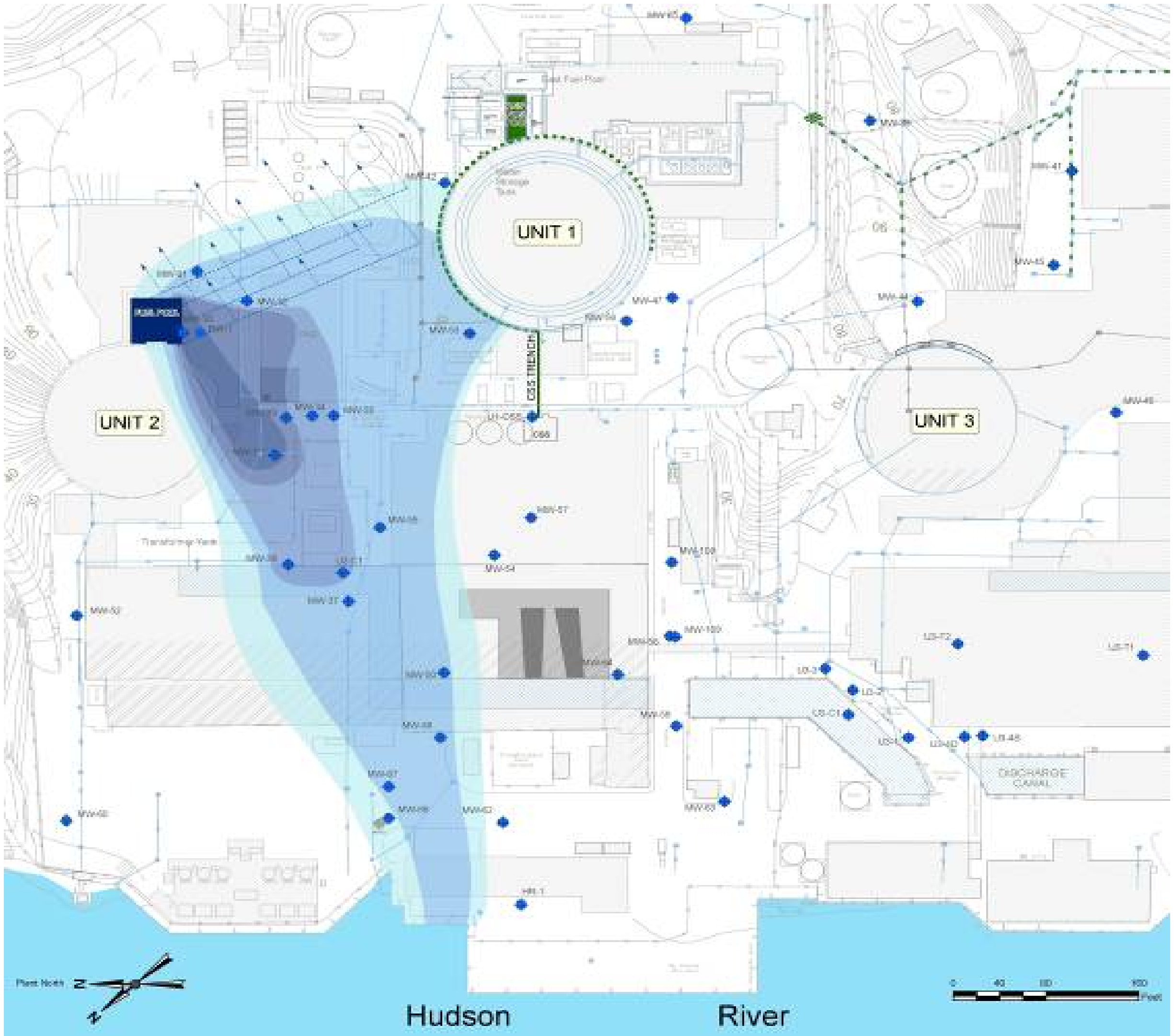
Plume Characteristics and Leak Behavior



- Site conceptual hydrology model is robust and extensively documented.
- Over 40 monitoring wells, most of which are multi-level and range up to ~300’ in depth
- Wells are configured with level transducers and sample ports for chemical/radiological sampling
- Plume characteristics and leak behavior understood in 3D space and time.
- Long-term monitoring program is institutionalized
  - Assess plume attenuation
  - Radiological dose assessment
  - Ongoing capability for detecting new leaks should they occur
  - No tritium found in offsite wells.

IP2 Spent Fuel Pool Leak





Unit 2 Source Map

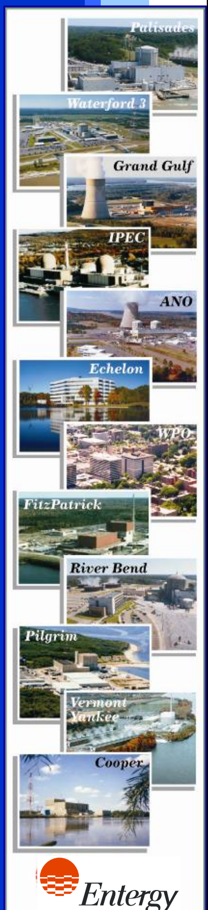
GW flow is west to river

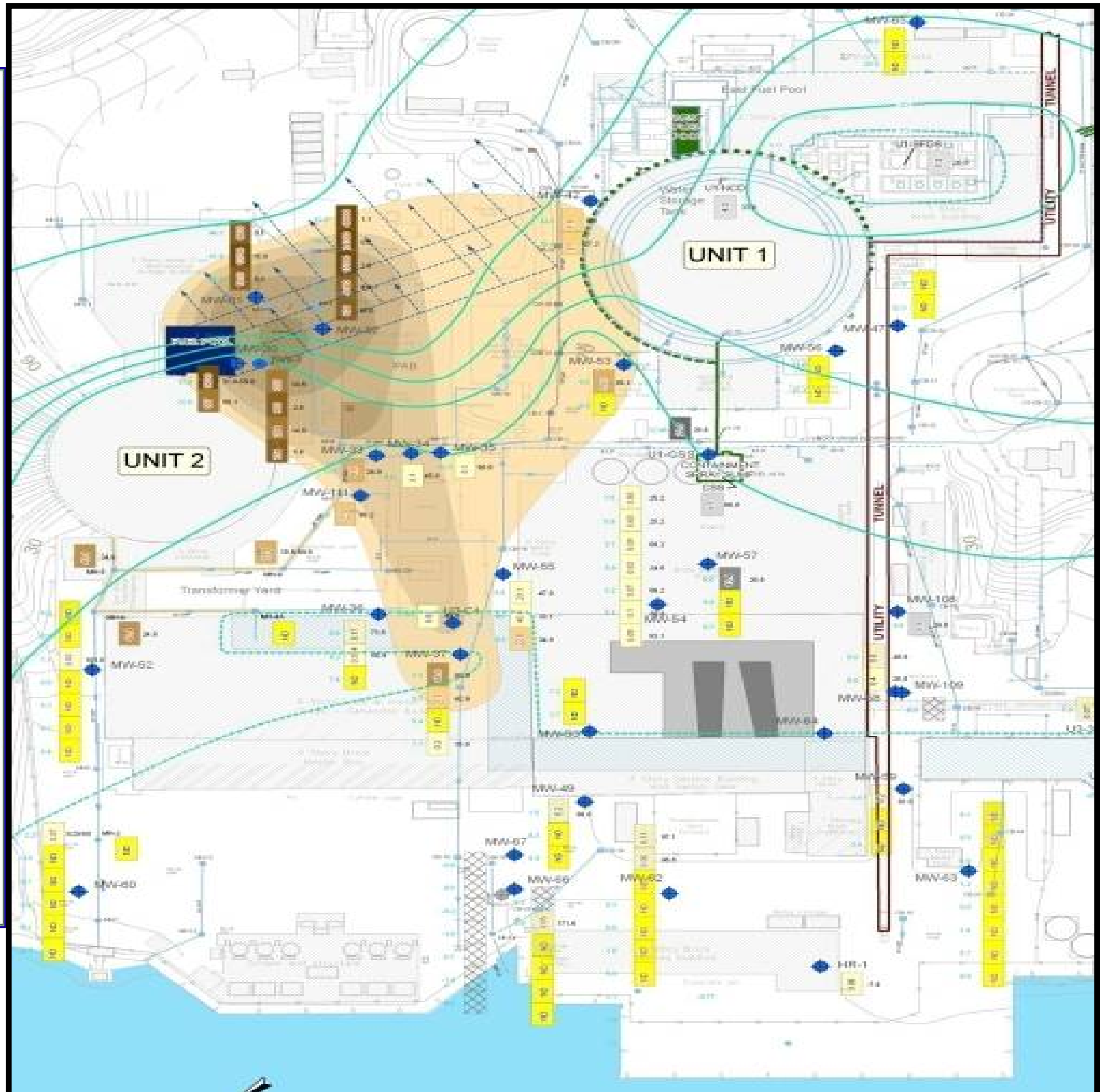
Wells provide “sentinel” and broad base monitoring

Detection capability of leak near pool confirmed via dye testing

[Tritium Plume]

IP2 Spent Fuel Pool Leak





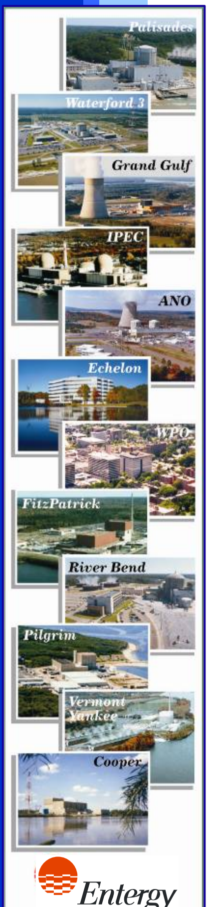
Tracer Test

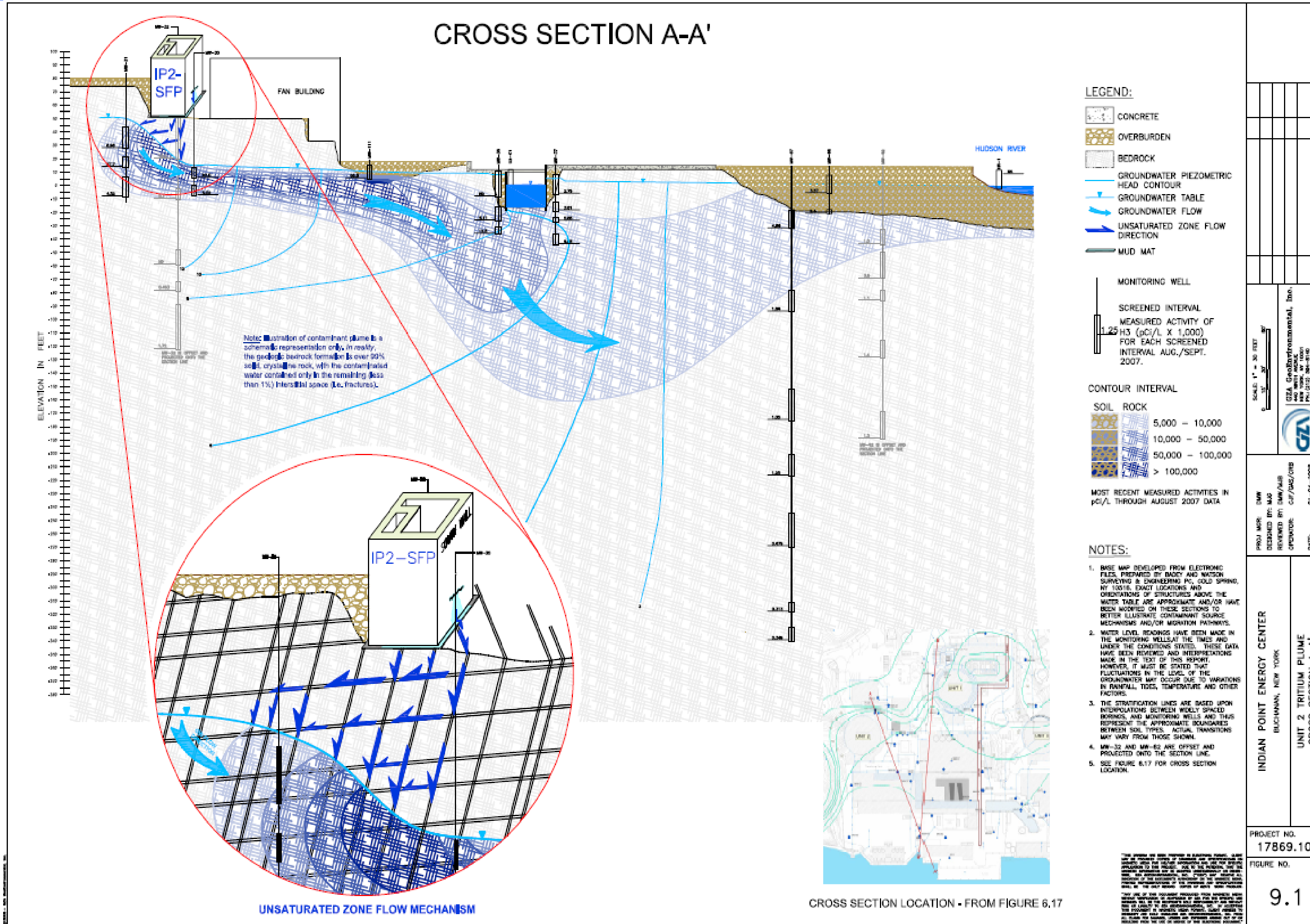
Multi month test adds confirmatory data to conceptual model

Supports retention mechanism at Unit 2 pool

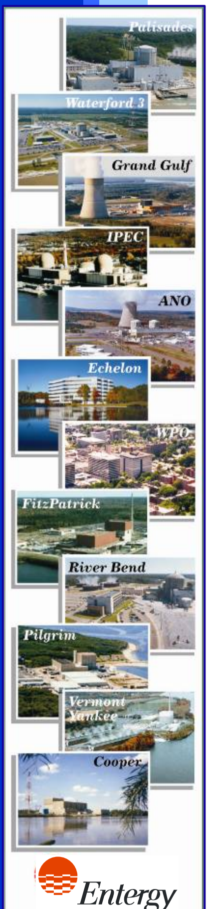
Connectivity between Units 2 and 1 observed

IP2 Spent Fuel Pool Leak





Comments and Questions



UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Advisory Committee on Reactor Safeguards

Indian Point Nuclear Generating Unit Nos. 2 and 3 Safety Evaluation Report

September 10, 2009

Kimberly Green, Project Manager
Office of Nuclear Reactor Regulation

Overview

- NRC Staff Review
- License Renewal Inspections
- Items of Interest

NRC Staff Review

- LRA submitted by letter dated April 23, 2007
- 121 RAIs
- 5 Audits
  - 272 audit questions
- 4 Inspections
  - Inspection Report issued August 1, 2008
- Safety Evaluation Report with Open Items issued January 15, 2009
  - 20 open items

NRC Staff Review (cont.)

- Applicant submitted additional information by letters dated 1/27/09, 5/1/09, and 6/12/09 to address open items
- Staff closed all 20 open items
- SER issued on August 11, 2009
- Staff determined that the requirements of 10 CFR 54.29(a) have been met

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Protecting People and the Environment

License Renewal Inspections

Glenn Meyer

Region I Inspection Team Leader

License Renewal Inspections

- 7 Aging Management Program concerns addressed
- Containment exterior addressed by Commitment 37
- Follow up on IP2 SBO diesel, electrical cable vault, and IP2 containment liner
- Scoping of nonsafety-related equipment is adequate

ACRS Items of Interest

- Buried Piping and Tanks Inspection Program
- Metal Fatigue
- Flow-Accelerated Corrosion (FAC)
- Upper-Shelf Energy (USE) Criteria

Buried Piping and Tanks Inspection Program

- Buried Piping and Tanks Inspection Program is a new program
- Program is consistent with the GALL AMP XI.M34, Buried Piping and Tanks Inspection
- GALL Report recommends:
  - one inspection prior to entering period of extended operation (PEO) and one during first 10 years of PEO
  - plant-specific operating experience be further evaluated for PEO
- Recent operating experience (OE) in February 2009 — IP2 condensate return line leak
- Amended program to incorporate recent OE

Amended Buried Piping and Tanks Inspection Program

- Applicant will perform 51 inspections prior to entering PEO
- Committed to periodic inspections using inspection methods with demonstrated effectiveness during PEO
- Number and inspection frequency based on:
  - Results of the planned inspections prior to the PEO
  - Other applicable industry OE
  - Plant-specific OE
  - Classification of piping/tanks and corrosion factors
- Staff concluded amended program adequate to manage aging effects

Metal Fatigue

- Applicant projected 60-year environmentally adjusted fatigue CUFs for NUREG/CR-6260 locations, except 2 locations (IP2) and 3 locations (IP3)
- Committed to manage aging for all NUREG/CR-6260 locations in accordance with 10 CFR 54.21(c)(1)(iii)

Metal Fatigue (cont.)

- Fatigue Monitoring Program
  - Consistent with GALL AMP X.M1, Metal Fatigue of Reactor Coolant Pressure Boundary
    - Incorporates environmental fatigue effects
    - Monitors the number of critical thermal and pressure transients
    - Maintains cumulative usage factor (CUF) below the design limit of 1.0
    - Periodic CUF updates
    - Action limit - triggers corrective actions
    - Corrective actions – repair, replacement or refined analyses
- Staff concluded applicant’s program is adequate

Flow-Accelerated Corrosion Operating Experience

- In instances where minimum measured wall thickness was near or below minimum acceptable wall thickness:
  - Replaced affected piping sections
  - Expanded inspections
  - Included results in program

Flow-Accelerated Corrosion

- Consistent with GALL AMP XI.M17, Flow-Accelerated Corrosion, with one exception
  - Use EPRI NSAC-202L-R3 in lieu of NSAC-202L-R2
- All other program elements are consistent with GALL Report AMP
  - Updated inputs to the IP2 and IP3 Flow-Accelerated Corrosion Programs to include power uprate operating parameter changes
  - Identified piping systems and components that are currently most susceptible to loss of materials by FAC
  - Corrective actions include reevaluation, repair, or replacement
- Staff concluded applicant's program is adequate

Upper-Shelf Energy Criteria

- 10 CFR Part 50, Appendix G
  - Reactor vessel must maintain Charpy upper-shelf energy (USE) of no less than 50 ft-lb unless 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
- Appendix K of ASME Code Section XI and ASME Code Case N-512 provide criteria for reactor vessels with Charpy USE values less than 50 ft-lb

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Upper-Shelf Energy Criteria (cont.)

- Draft Guide DG-1023 and Regulatory Guide (RG) 1.161 provide NRC guidance in performing the ASME Code equivalent margins USE analyses
- RG 1.99, Revision 2 provides NRC guidance for determining the impact of neutron irradiation on Charpy USE

Upper-Shelf Energy Criteria (cont.)

- Applicant has projected the Charpy USE at the end of the period of extended operation in accordance with RG 1.99, Revision 2:
  - IP2: 48.3 ft-lb
  - IP3: 49.8 ft-lb
- Applicant submitted equivalent margins analysis
- WCAP-13587, Revision 1 demonstrates that 4-loop plants can meet ASME Code requirements at 43 ft-lb
- Applicant demonstrated that the analyses in WCAP-13587, Revision 1 are applicable to IP2 and IP3

Upper-Shelf Energy Criteria (cont.)

- Staff determined IP2 and IP3 reactor vessels will satisfy the Charpy USE requirements of 10 CFR Part 50, Appendix G at the end of the PEO
  – Analyses in WCAP-13587, Revision 1 are applicable to IP2 and IP3
  – Staff approved WCAP-13587, Rev. 1 in April 1994
  – Projected Charpy USE values are greater than minimum allowables determined in WCAP-13587, Revision 1

Back Up Slides

Auxiliary Feedwater Pump Room Fire Event

- Auxiliary feedwater (AFW) Pump Room Fire Event at IP2
  - Does not have automatic suppression
  - Relies on main feedwater (MFW) to feed steam generators (SGs)
- AFW Pump Room Fire Event at IP3
  - Has automatic suppression
  - Does not rely on MFW to feed SGs
- Staff agrees that AFW fire event at IP3 does not require additional components be included in scope for license renewal

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IP2 Refueling Cavity Leakage

- Leakage originally documented in 1993
- Currently no indications of degradation based on bore samples and subsequent visual inspections
- Applicant committed to take bore samples during 2010 outage
- Applicant plans to fix leak by 2014 outage
- If fix is unsuccessful, bore samples will be taken and analyzed for structural integrity
- Staff concluded applicant's approach is adequate for managing aging effects in refueling cavity concrete

IP2 Spent Fuel Pool Leakage

- Originally observed and repaired in 1992
- “Wetting” observed in 2005
- In 2007, applicant inspected and tested accessible areas of the pool liner and believes it eliminated all known leakage sources
- Applicant stated there is currently no evidence of leakage
- In addition to inspections under the Structures Monitoring Program, applicant committed to quarterly samples of groundwater for indications of leakage
- Applicant concluded the structure has significant margin
- Staff concluded applicant’s approach is adequate for managing effects of aging for SFP structure

Containment Concrete Degradation

- Spalls first documented in 2000 IWL inspection
- 2005 IWL inspection found little or no change
- 2009 follow-up inspections also found little or no change
- Based on OE and commitment to include enhanced visual inspections, IWL inspection frequency is adequate
- Applicant concluded the structure has significant margin
- Staff concluded applicant’s approach is adequate for managing aging effects of containment structures

Concrete Aging

- Staff confirmed durability of IP2 and IP3 concrete
- IWL and Structure Monitoring Programs will monitor concrete during PEO
- Staff concluded there is reasonable assurance that aging will be adequately managed

Cooling of Concrete Surrounding Penetrations

- The LRA was unclear on the temperatures surrounding hot penetrations
- Applicant explained that it maintains temperature below 200ºF
- Via OE review, applicant confirmed the temperature remained below the limit

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IP2 Water Hammer Event

- Feedwater line rupture occurred in 1973 which damaged the liner
- No indications of concrete damage from exterior IWL inspections
- Successful integrated leak rate tests since incident
- Current OE does not indicate concrete damage behind liner that would affect containment structural integrity
- Applicant committed to remove insulation and inspect an area of liner affected by the 1973 event
- If the one-time liner inspection indicates degradation, applicant will review issue

13 Open Items Needed Clarification

- OI 2.3A.3.11-1: AMR of yard hose houses and chamber housings
- OI 2.3.4.2-1: Scoping of main feedwater isolation valves
- OI 2.5-1: SBO scoping boundary
- OI 3.0.3.2.7-1: Fire penetration seals
- OI 3.0.3.3.3-1: Acceptance criteria for visual examinations
- OI 3.0.3.3.4-1: Inspection methods for lubrite sliding supports
- OI 3.0.3.3.4-2: Corrective actions for ISI
- OI 3.0.3.3.7-1: Periodic Surveillance and Preventive Maintenance Program
- OI 3.1.2-1: Nickel alloy components
- OI 3.1.2.2.7-1: Inspection of CASS
- OI 3.3-1: Clarification of material, environment, and aging effect for titanium components
- OI 3.5-3: Aging management of concrete surrounding B1 supports
- OI 4.3-1: Cycle counting

7 Open Items Needed Further Evaluation

- OI 2.3.4.5-1: AMR results of systems needed during AFW pump room fire event
- OI 3.0.3.2.15-1: IP2 reactor refueling cavity leakage
- OI 3.0.3.2.15-2: IP2 spent fuel pool leak
- OI 3.0.3.3.2-1: Exterior containment concrete degradation
- OI 3.4-1: AMR results for components needed during a fire in IP2 auxiliary feedwater pump room
- OI 3.5-1: Water-cement ratio for concrete
- OI 3.5-2: Reduction of strength and modulus of concrete due to elevated temperatures


Three Mile Island
Generating Station - Unit 1
License Renewal Application
ACRS Presentation
September 10, 2009.

INTRODUCTIONS

– Mike Gallagher	VP, Exelon License Renewal
– Dave Atherholt	TMI-1 Regulatory Assurance Manager
– Al Fulvio	Manager, License Renewal
– Pat Bennett	TMI-1 Engineering Manager
– Chris Wilson	Licensing Lead

AGENDA

• Introductions	Mike Gallagher
• Site Description	Dave Atherholt
• ACRS Subcommittee Follow-up Item	Al Fulvio
– Operating Experience Review	
• Gall Consistency and Commitments	Al Fulvio
• Containment	Pat Bennett
• Medium Voltage Cables	Dave Atherholt
• Current Industry Issues	Al Fulvio
– SBO, Boral, Fatigue	
• Questions?	Mike Gallagher

SITE DESCRIPTION

TMI-1 is a Babcock and Wilcox (B&W) Pressurized Water Reactor located on Three Mile Island, which is situated in the Susquehanna River

➢ Commercial Ops	09/74
➢ TMI-2 Accident	03/79
➢ TMI-1 stays shutdown	03/79
➢ TMI-1 Restart	10/85
➢ 1.3 percent power uprate to 2568 MWt	07/88
➢ Sale of TMI-1 from GPU to AmerGen	12/99
➢ Turbine Rotor replacements	11/01
➢ Main and Aux Transformers replacement	11/01
➢ New Reactor Head	11/03
➢ LRA Submitted	01/08
➢ Transfer license from AmerGen to Exelon	01/09
➢ Scheduled installation of new S/Gs (1R18)	Fall 2009
➢ Two consecutive breaker to breaker runs	2001-2005
➢ Unit Capability Factor (2007 & 2008 average)	95.28%
➢ Current License Expires	04/19/14

ACRS SUBCOMMITTEE FOLLOW-UP ITEM:
OPERATING EXPERIENCE REVIEW

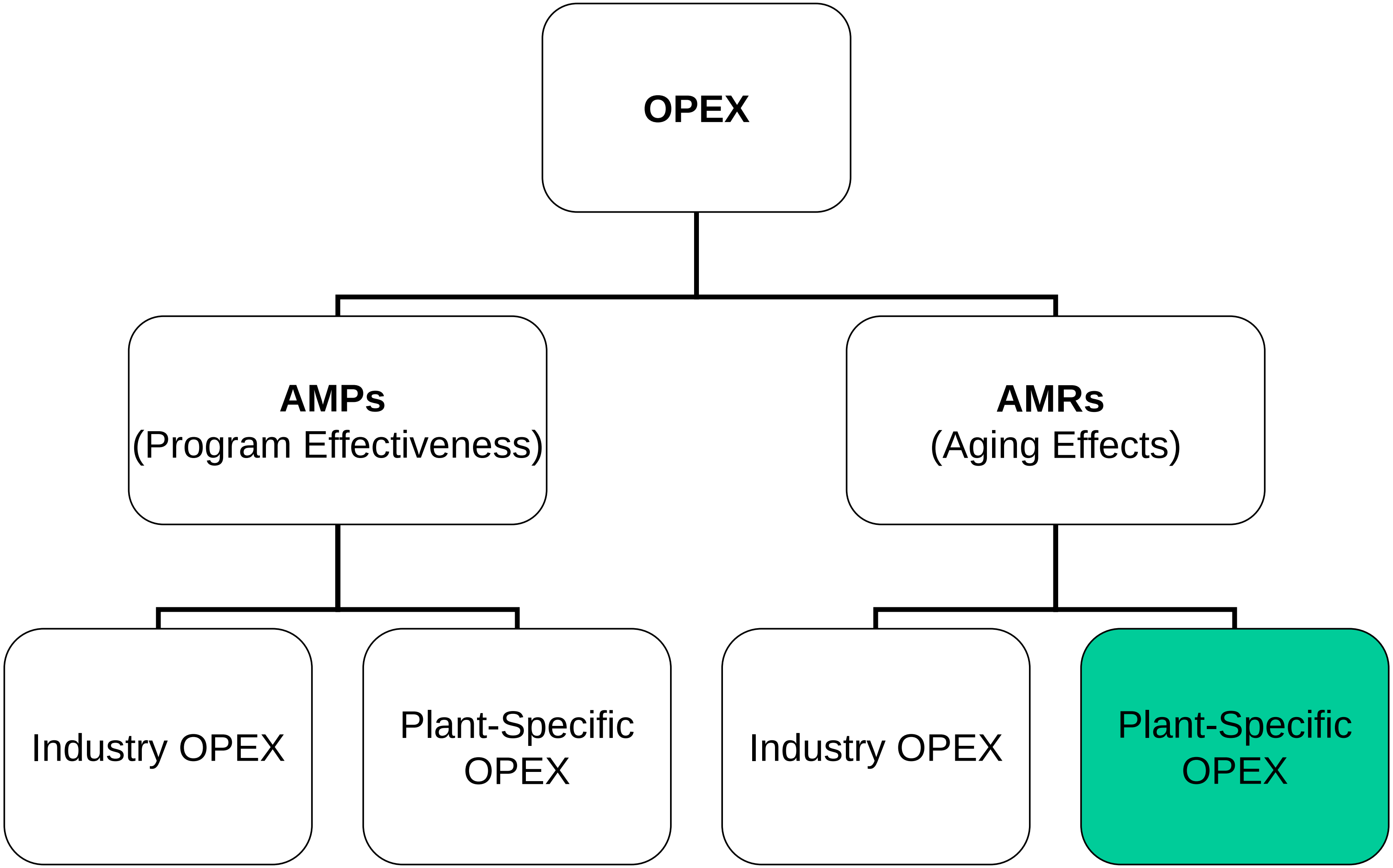
OPERATING EXPERIENCE REVIEW

Issue:

NEI 95-10 recommends a plant specific operating experience review for aging effects requiring management.

TMI-1 credited the EPRI Mechanical Tools for a part of the Mechanical Systems Operating Experience Review for aging effects requiring management.

OPERATING EXPERIENCE REVIEW (OPEX)



OPEX REVIEW FOR LICENSE RENEWAL APPLICATION

AMR
(Aging Effects)

Industry OPEX

Plant-Specific
OPEX

GALL,NRC and INPO

5 years of Industry
OPEX Reviewed

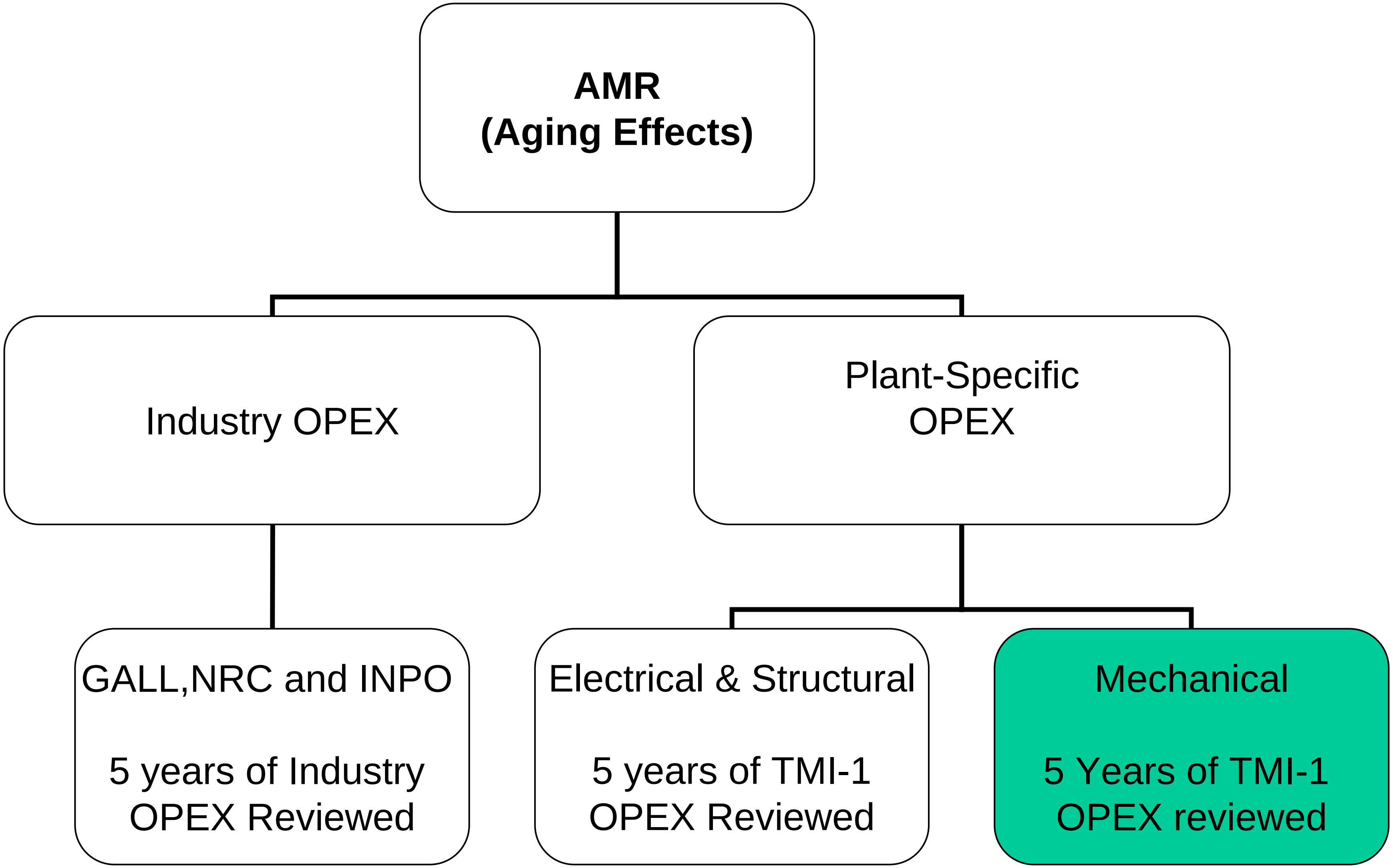
Electrical & Structural

5 years of TMI-1
OPEX Reviewed

Mechanical

EPRI Tools 3 years
TMI-1 Specific 2 Years

OPEX REVIEW VALIDATION MAY 2009



OPEX REVIEW SUMMARY AND CONCLUSION

- EPRI Mechanical Tools were credited for 3 years of Operating Experience for plant specific aging effects requiring management.
- In order to validate the original review, a TMI-1 plant specific Operating Experience review was recently conducted for the 3 year period that the EPRI Mechanical Tools were credited
  - No new aging effects were identified
- Conclusion: The results of the Operating Experience review performed during the Application development were validated.

GALL CONSISTENCY AND COMMITMENTS

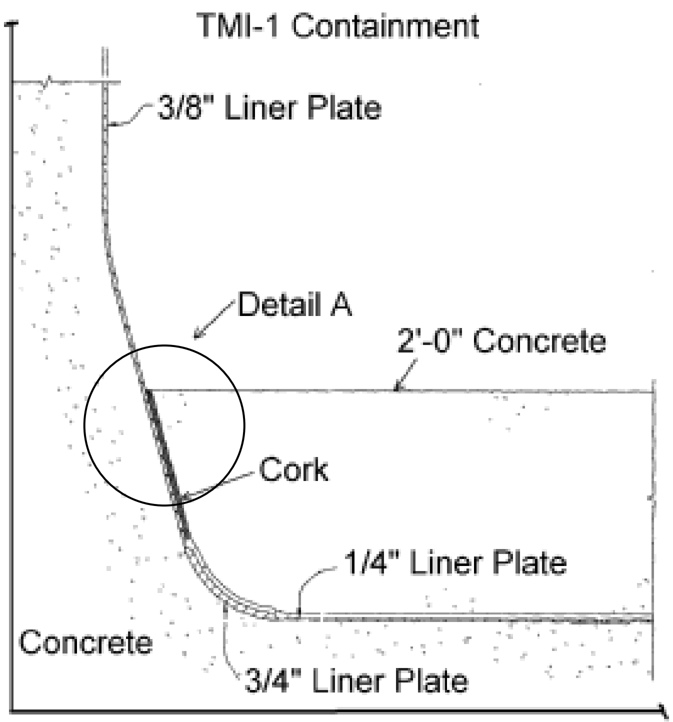
GALL CONSISTENCY AND COMMITMENTS

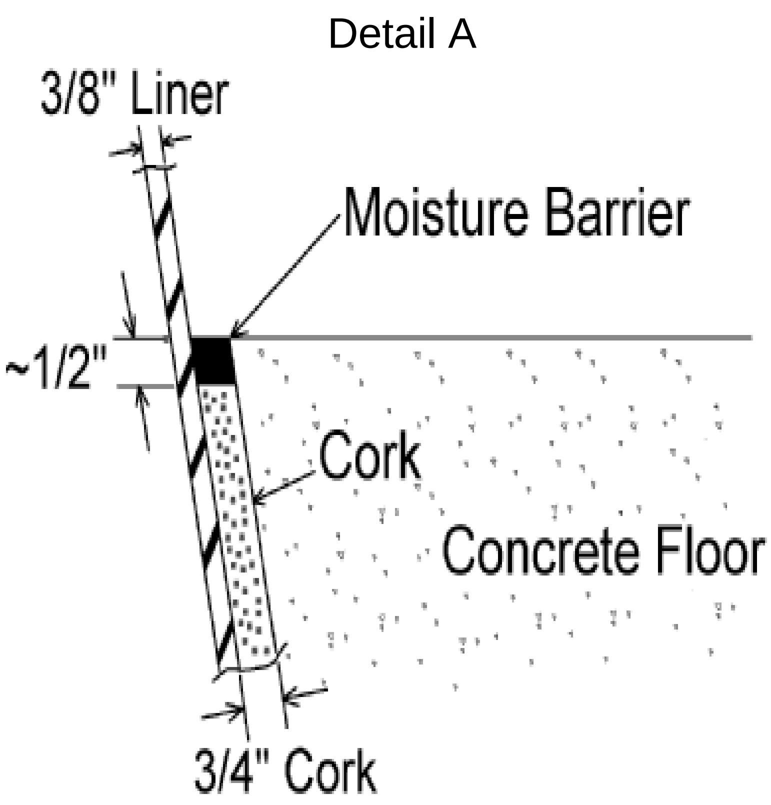
- Total Aging Management Programs – 38
  - Consistent with GALL – 24
  - Exceptions to GALL – 14
- Total of 43 License Renewal Commitments
  - 38 Aging Management Programs
  - PWR Vessel Internals
  - Install new Steam Generators prior to PEO
  - Submit new Pressure-Temperature limit curves to the NRC prior to exceeding 29 EFPY and prior to PEO
  - Weld repair the Reactor Building liner prior to the PEO
  - Boral Test Coupon Surveillance for the fuel storage racks will continue through the PEO

CONTAINMENT

CONTAINMENT

ISSUE: Past leakage and a degraded moisture barrier resulted in corrosion behind and just above the moisture barrier.

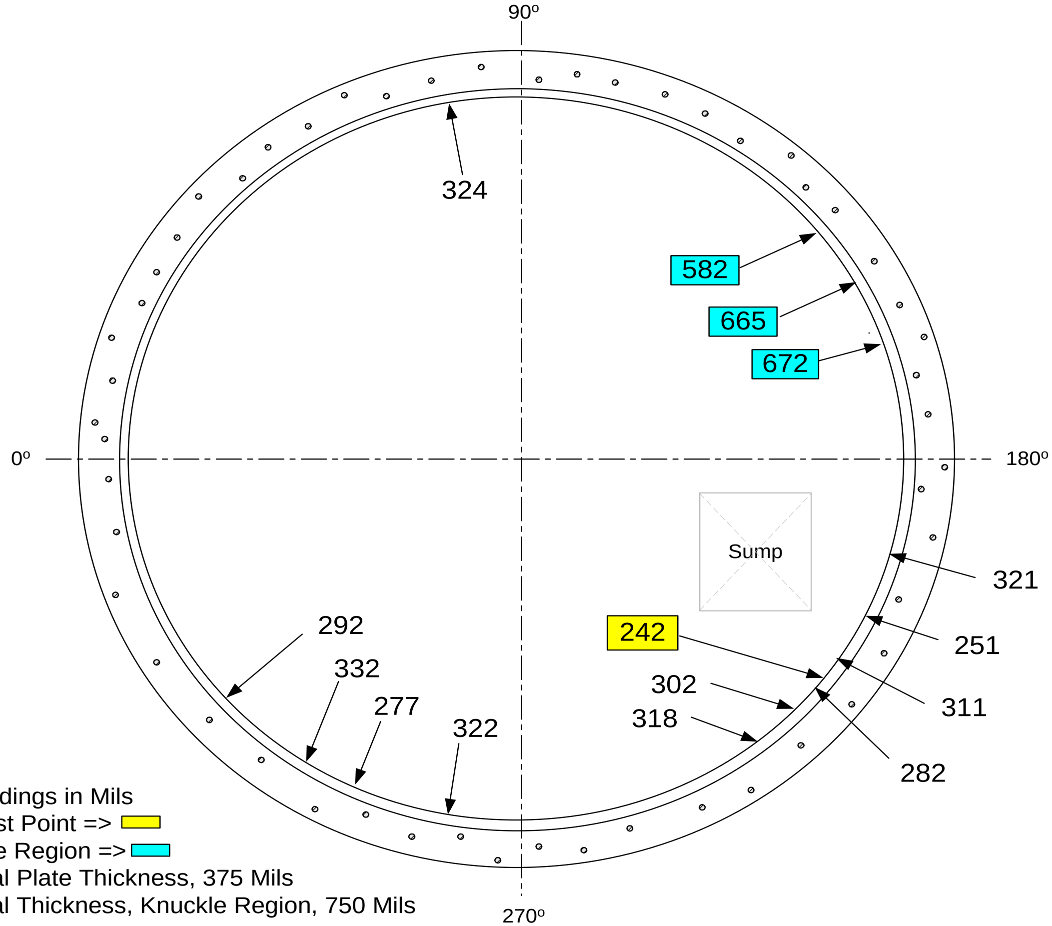




Containment

Areas of Corrosion at Moisture Barrier to Liner interface

Plant North



Legend:
All Readings in Mils
Thinnest Point =>
Knuckle Region =>
Nominal Plate Thickness, 375 Mils
Nominal Thickness, Knuckle Region, 750 Mils

CONTAINMENT

- Identified
  - Corrosion identified in 1990s and monitored and inspected per IWE Program
- Cause
  - Borated water leakage and degraded moisture barrier
- Mitigation
  - Corrected leaks and established Boric Acid Corrosion Control program
  - Inspected entire perimeter in Fall 2007
  - Measured thickness of corroded areas. Liner meets design requirements.
  - Removed old moisture barrier in 2007, cleaned, re-coated, and installed new improved moisture barrier
  - Inspect 100% of the moisture barrier every Refueling outage starting 2009
- Repair Plan
  - Weld repair prior to PEO (scheduled Fall 2009 with the Integrated Leak Rate Test)

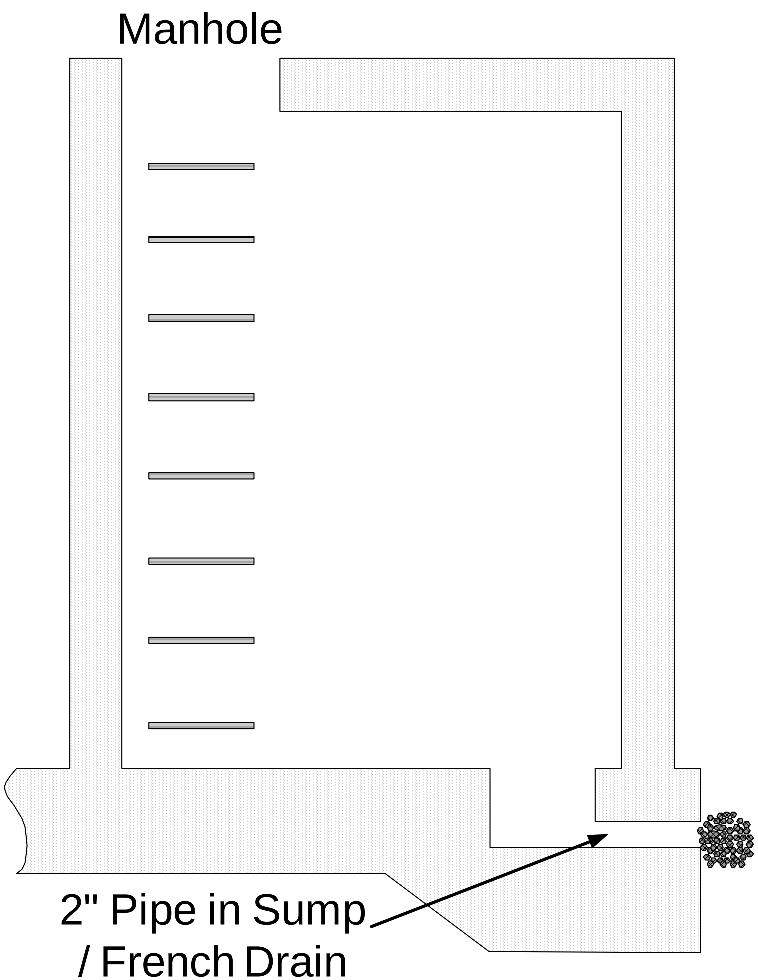
MEDIUM VOLTAGE CABLES

MEDIUM VOLTAGE CABLES

ISSUE

- Periodic TMI-1 cable vault inspection results identified some cable vaults with repeat occurrences of rainwater accumulation and cable submergence
- 37 total TMI-1 cable vaults
- 8 cable vaults in scope for License Renewal Inaccessible Medium Voltage Cable aging management program
- There have been no failures of Medium Voltage Cables at TMI-1

MEDIUM VOLTAGE CABLES



Typical Cable Vault

- Typical depth 8 to 15 feet
- Bottom of Cable Vault located 5 to 15 feet above water table
- Compartmentalized
- French drain
- Cables at varying elevations reflecting terrain & cable routes

MEDIUM VOLTAGE CABLES

<u>ACTIONS</u>

- Implement semi-annual inspection
- Implement cable vault improvement initiative, including:
  - Prevent rainwater intrusion
    - Install lid gaskets
    - Improve grading/surrounding environment to prevent run-off into vaults
  - Restore/maintain French drains & drains between vaults
- Adjust frequency of inspection based on inspection results following remediation
- Perform Cable Tests prior to PEO and every 10 years per GALL

<u>CONCLUSION</u>

- This new Program will keep the medium voltage cables dry or infrequently submerged to effectively manage aging.

CURRENT INDUSTRY ISSUES

CURRENT INDUSTRY ISSUES

- Station Blackout
  - TMI-1 LRA boundary for SBO recovery path includes the switchyard circuit breakers
- Boral
  - The TMI-1 Boral coupon surveillance program will continue throughout the period of extended operation
- Fatigue
  - Environmentally-Assisted Fatigue has been satisfactorily evaluated
  - No simplified analysis methods were used

QUESTIONS?

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Advisory Committee on Reactor Safeguards (ACRS)
Three Mile Island Nuclear Station, Unit - 1 (TMI-1)

Safety Evaluation Report (SER)

September 10, 2009

Jay E. Robinson, Project Manager
Office of Nuclear Reactor Regulation

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Introduction

- Review
- License Renewal Inspections/Operating Experience Review
- Section 2: Scoping and Screening Review
- Section 3: Aging Management Program and Review Results
- Section 4: Time-Limited Aging Analyses (TLAAs)
- Conclusion

Review

- Application Submitted January, 2008
- Staff Conducted Scoping Screening Audit, AMP Audit, and Regional Inspection
- Additional Components Brought into Scope
- 123 RAIs issued
- 43 Commitments
- SER with Open Items issued March, 2009
  - No Open Items (OIs)
  - One Confirmatory Item
    - Dissolved Oxygen

License Renewal Inspection Operating Experience

- Operating Experience Review
  - Applicant credited EPRI Tools in the mechanical system operating experience review for aging effects requiring management
  - Different from approach described in NEI 95-10
  - Applicant subsequently conducted a plant specific operating experience review for the period EPRI Tools were previously credited
  - No new aging effects were identified
  - Confirmed by staff during inspection on July 7th
  - Additional inspection report issued
  - SER to be updated accordingly

License Renewal Inspection Conclusion

- Inspection Conclusions
  - Scoping of non-safety SSCs and aging management programs are acceptable
  - Inspection results support a conclusion of reasonable assurance that aging effects will be managed and intended functions will be maintained

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 Systems
- Section 2.4 – Scoping and Screening Results: Structures
- Section 2.5 – Scoping and Screening Results: Electrical Systems/Commodity Groups
- Section 2.6 – Conclusion for Scoping and Screening

Section 2: Structures and Components Subject to Aging Management Review

- Section 2.3 – Scoping and Screening Results: Mechanical Systems
  - The staff identified nine systems that required the applicant to revise their application to add additional components into scope
    - Examples of component types omitted included: Fuel tank for the standby diesel engine for the emergency diesel generator air start system air compressor, lube oil lines, and intake bar racks, which were subsequently added to scope and subject to an AMR
- Section 2.4 – Scoping and Screening Results: Structures
  - The staff identified one component that required the applicant to revise their application to add the component into scope

- Section 2.6 – Conclusion for Scoping and Screening
  - Based on its review of the LRA, the onsite audit results, and additional information submitted as the result of RAIs, the staff concluded that:
    - The applicant's scoping and screening methodology meets the requirements of 10 CFR 54.4 and 54.21(a)(1), and
    - The applicant adequately identified those SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a), and adequately identified those SCs subject to an AMR in accordance with 10 CFR 54.21(a)(1)

Section 3: Aging Management Review Results

- Section 3.0 – Aging Management Programs
- Section 3.1 – Reactor Coolant System
- 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 Commodity Group

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Section 3: Aging Management Review Results

- Section 3.0.3 – Aging Management Programs (AMPs)
  - 38 – AMPs
    - 7 New Programs
    - 31 Existing Programs
  - 21 consistent with GALL Report
    - 9 with enhancements
    - 1 plant specific
  - 11 with exceptions
  - 6 with both enhancements and exceptions

Section 3: Aging Management Review Results

- Groundwater
  - Non-aggressive for steel embedded in concrete
  - Sampling every 5 years during the period of extended operation
- Reactor Building Liner
  - Corrosion due to moisture intrusion through moisture barrier
  - Current function maintained through engineering evaluation
  - Applicant committed to restore liner to its nominal plate thickness by weld repair prior to PEO

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Section 3: Aging Management Review Results

- **Inaccessible Medium Voltage Cables**
  - Some inaccessible medium-voltage cables in some manholes experienced water submergence for more than a few days
  - Staff found cables submerged under water in two manholes during audit
  - Applicant will adjust frequency of inspections based on inspection results
  - Water in manholes is also a generic, current operating plant issue that is being addressed in accordance with the requirements of 10 CFR Part 50
- **Reduction of Neutron-Absorbing Capacity**
  - Water Chemistry Program & Boral Surveillance Program
  - Commitment to continue Boral test coupon surveillance through period of extended operation
- **Conclusion**

Section 4: Time-Limited Aging Analysis

- 4.1 Introduction
- 4.2 Neutron Embrittlement of the Reactor Vessel and Internals
- 4.3 Metal Fatigue of Piping and Components
- 4.4 Leak-Before-Break Analysis of Primary System Piping
- 4.5 Fuel Transfer Tube Bellows Design Cycles
- 4.6 Crane Load Cycle Limits
- 4.7 Loss of Prestress in Concrete Containment Tendons
- 4.8 Environmental Qualification of Electrical Equipment

Section 4: Time-Limited Aging Analysis

- Section 4.3.2 – Evaluation of Reactor Water Environmental Effects on Fatigue Life of Piping and Components, GSI-190
  - Confirmatory Item 4.3.2-1
    - Fen values calculated based on assumed DO (dissolved oxygen) concentration data lower than 0.05 ppm
    - Staff questioned whether 0.05 ppm DO was bounding
    - Applicant indicated that 0.05 ppm was bounding since TMI-1 historically maintained its DO levels at less than 0.005 ppm, and administrative controls are in place to maintain it at or below this level
    - Applicant submitted additional information and confirmed DO history since plant began operation. Staff found the information acceptable, closed out item, and revised SER

Section 4: Time-Limited Aging Analysis

- Section 4.9 – Conclusion
  - Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that the applicant provided an adequate list of TLAAs, per 10 CFR 54.3 and that the:
    - TLAAs will remain valid for the period of extended operation, per 10 CFR 54.21(c)(1)(i)
    - TLAAs have been projected to the end of the period of extended operation, per 10 CFR 54.21(c)(1)(ii)
    - Aging effects will be managed for the period of extended operation, per 10 CFR 54.21(c)(1)(iii)

Conclusion

- The staff has concluded there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB and that the requirements of 10 CFR 54.29(a) have been met.

Daniel Frumkin

Fire Protection Branch

Division of Risk Assessment

Office of Nuclear Reactor Regulation

DG-1214, Fire Protection for Nuclear Power Plants

ACRS

September 10, 2009

Topics

- Background
- Changes in Draft Guide
- Public comments
- Public comments not incorporated
  - Clearing of Hot Shorts within 20 Minutes for Components Important to Safe Shutdown
  - Appendix E of NEI 00-01 – Operator Manual Actions
  - Concurrent Hot Shorts in Separate Cables for Components Important to Safe Shutdown
- Path forward

Background (1)

- Proposed resolution to multiple spurious actuations in SECY 06-0196, "Issuance of Generic Letter 2006-xx, "Post-Fire Safe-Shutdown Circuits Analysis Spurious Actuations"
- SRM/SECY 06-0196:
  - "The present draft of the proposed Generic Letter does not contain the necessary specificity for a licensee to understand what process will be sufficient to meet the analysis needs and information demands of the draft Generic Letter"
  - "The staff should <u>examine licensee analysis methods</u> in this area, including those using system or functional scenario development approaches, and using the <u>normal public regulatory process</u> to <u>enable stakeholder engagement</u>, <u>develop or endorse guidelines</u> that provide a <u>clearly defined method of compliance</u> for licensees who do not choose to utilize the risk-informed approach contained in 10 CFR 50.48(c)." Emphasis Added

Background (2)

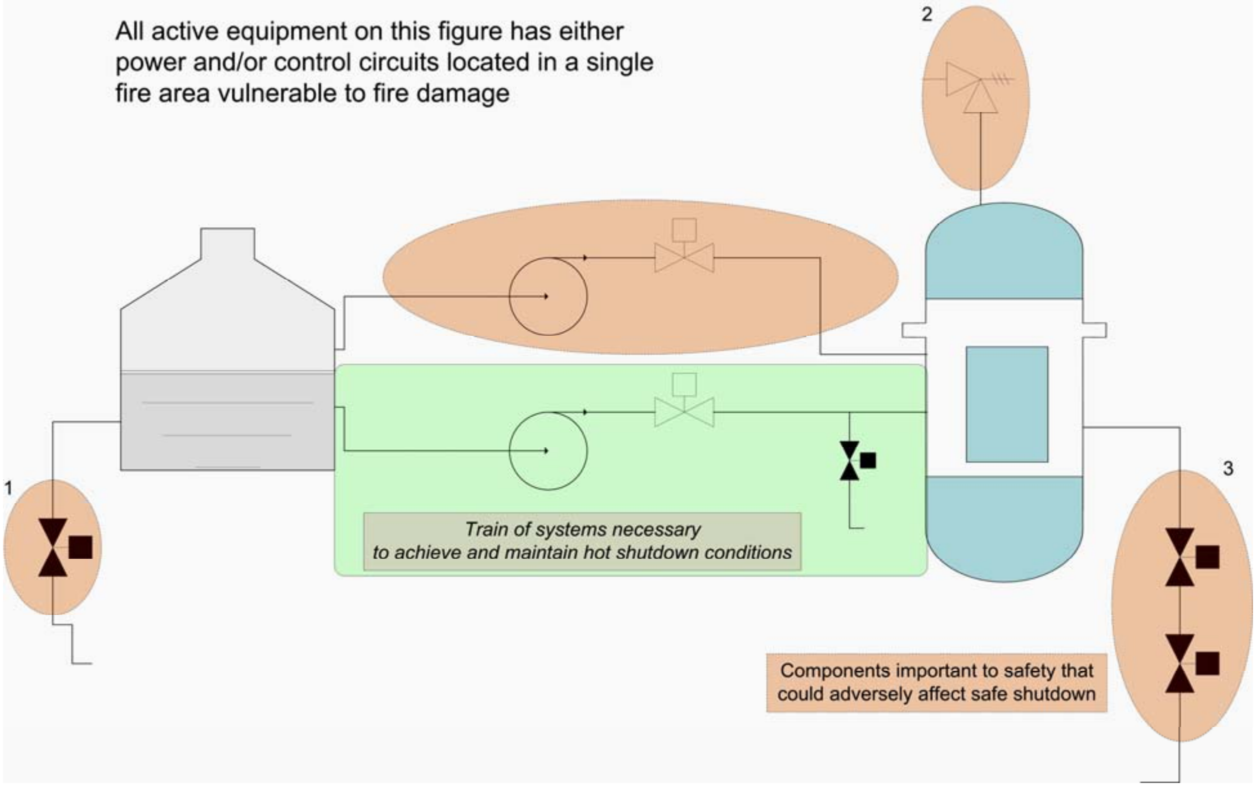
- Rule Language – 10 CFR 50, Appendix R, III.G.1
  - "where cables or equipment . . . of redundant trains of systems necessary to achieve and maintain hot shutdown conditions are located within the same fire area . . ., one of the following means of ensuring that one of the redundant trains is free of fire damage shall be provided:"
    - 3 hour fire barrier
    - 20' and suppression and detection
    - 1 hour barrier and suppression and detection
- To summarize – only equipment necessary to achieve and maintain hot shutdown conditions is required to have III.G.2 protection provided

Background (3)

- Two categories of equipment were identified in SECY 08-0093:
  - Safe Shutdown Success Path
    - Also “Green Box” or “Components Required for Hot Shutdown”
  - Components Important to Safe Shutdown
    - Also “Orange Box”
- Although both require protection – only Safe Shutdown Success Path Components require Appendix R, III.G.2 protection

Background (4)

- SECY 08-0093, “Resolution of Issues Related to Fire-Induced Circuit Failures.”



Changes in Draft Guide

- The NRC initiated changes relate to Regulatory Position C.5 of the Guide. These changes include discussions of:
  - Safe shutdown success path components and components important to safety
  - Use of manual actions and fire modeling for assessing components important to safe shutdown
  - Examples of the safe shutdown success path components and important to safe shutdown components

Public Comments (1)

- Three industry stakeholders provided comments
  - Nuclear Energy Institute, on behalf of their members (83 Comments)
  - Dominion (3 comments)
  - Florida Power and Light (11 comments)
- Industry stakeholders commented that NEI 00-01, Revision 2 should be reference in the guide – this comment was consistent with Commission direction and was done except as explained below

Public Comments (2)

Total Comments	97
Comments Incorporated	53
Comments Incorporated in Part	11
Comments Not Incorporated – Discussed on following pages	21
Duplicate Comments	9
Observations – with no recommended changes	3

Public Comments Not Incorporated

- The main reason for non-acceptance of comments were along these themes:
  - The guide does not supersede a plants approved fire protection program – so no change was needed
  - Guidance is located elsewhere in the guide
  - There are means available to deviate from the regulatory guide
- Specific comments are discussed on the following slides

Clearing of Hot Shorts within 20 Minutes for Components Important to Safe Shutdown

- Two hot shorts of the body of testing of direct current (DC) circuits in ~32 tests didn't clear. This is not sufficient in the staff's opinion to justify setting a deterministic limit for DC circuit hot shorts to clear in 20 minutes.
- NEI's September 8, 2009, proposal agrees with the NRC staff position that DC circuits can't be assumed to clear in 20 minutes.
- The NRC staff and industry positions are the same with respect to DC circuit faults clearing

Appendix E of NEI 00-01 – Operator Manual Actions

- NEI 00-01 Appendix E lacks a clear discussion on reliability of manual actions
- Discussion with industry stakeholders indicate that for some scenarios the Appendix E timeline may be non-conservative, but in other scenarios it may be appropriate.
- The NRC staff position is that Appendix E, is not sufficient to address all plant response scenarios
- Implementing guidance on manual actions isn't necessary to bring circuit failure issues to closure

Concurrent Hot Shorts in Separate Cables for Components Important to Safe Shutdown (1)

- NEI 00-01, Rev. 2 proposed that only one cable be considered to have hot shorts for non-latching, non-locking circuits, and that concurrent multiple faults in separate cables need not be considered
- NRC staff express concerns with proposal this during the ACRS Subcommittee meeting
- NEI proposed in their September 8, 2009 letter to assume two separate cables experience concurrent hot shorts for non-latching, non-locking circuits

Concurrent Hot Shorts in Separate Cables for Components Important to Safe Shutdown (2)

- NRC has considered NEI's September 8, 2009, letter, and the DRA staff position regarding concurrent faults in non-latching and non-locking circuits of equipment important to safe shutdown is:
  - Licensees should consider concurrent fire-induced circuit failures in two separate cables, where defense-in-depth features are present.
  - For high low pressure interfaces, licensees should consider concurrent fire-induced circuit failures in three cables, where defense-in-depth features are present.
  - For multi-conductor cables, all circuit faults that could occur within the cable should be assumed to occur.

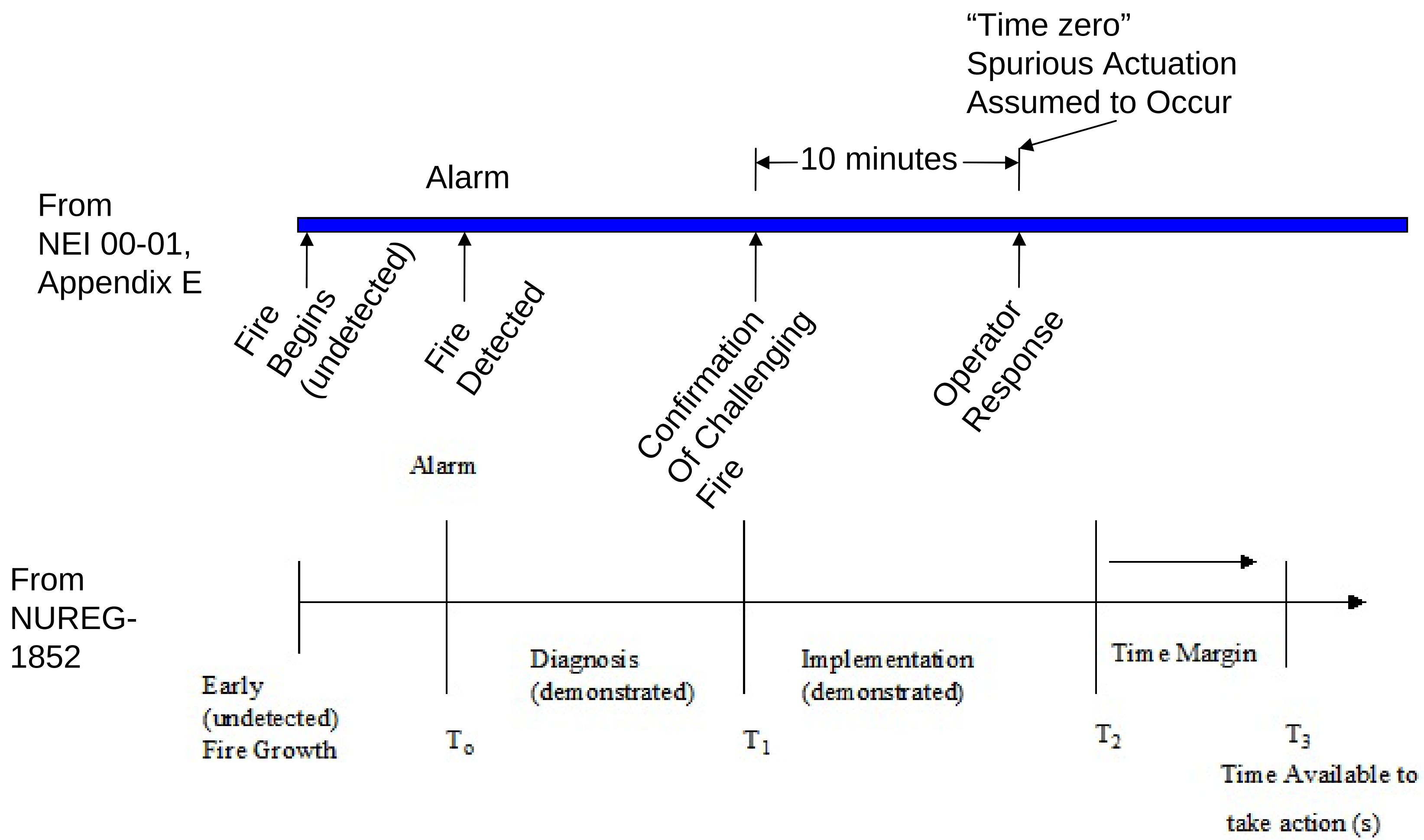
Path Forward (1)

- The NRC staff view is that there is sufficient guidance or alternatives available for licensees to complete fire induced circuit analyses
- The NRC staff has come to resolution with industry stakeholders on two of the issues identified. As more test data is available, the NRC staff will consider that information.
- NRC staff will continue to work with industry regarding refining the implementing guidance for operator manual actions, but this refinement is not necessary to fulfill the Commissions direction regarding a clearly defined method of compliance

Path Forward (2)

- Issuance of the Final Regulatory Guide 1.189 is planned for the fourth quarter of 2009
- Issuance of R.G. 1.189, will start the “clock” on Enforcement Guidance Memorandum (EGM) 09-002:
  - Licensees will have six months to identify noncompliances
  - And an additional 30 months to resolve those noncompliances
- The NRC will revise its inspection manual to assure that licensees are appropriately implementing the clarification described in RG 1.189

BACKUP SLIDE
Appendix E of NEI 00-01 – NUREG-1852



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NRC DIGITAL SYSTEM RESEARCH PLAN FY 2010 THROUGH FY 2014

Advisory Committee on Reactor Safeguards
September 10, 2009

Russell Sydnor
Daniel Santos
Division of Engineering
Office of Nuclear Regulatory Research
(301-251-7405, russell.sydnor@nrc.gov)
(301-251-7664, daniel.santos@nrc.gov)

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Purpose and Objectives

- **To obtain a letter of endorsement from the ACRS for the FY10-FY14 Digital System Research Plan**
- **To discuss and obtain insights from ACRS members on the strategic direction of Digital System regulatory research and improving the research plan**
- **Help answer the question: Are we missing something?**

Digital System Research Plan FY05 - FY09

- **Status as of 8/09: 7 research programs made up of 29 research projects and tasks**
  - **In 21 of 29 areas - significant research progress**
- **FY05 – FY09 Projects that were not started and not selected for FY10 – FY14 scope**
  - **COTS Digital Systems**
  - **THD effects on DI&C**
  - **Radiation Hardened ICs**
  - **Smart Transmitters**
  - **Advanced NPP Digital Risk**

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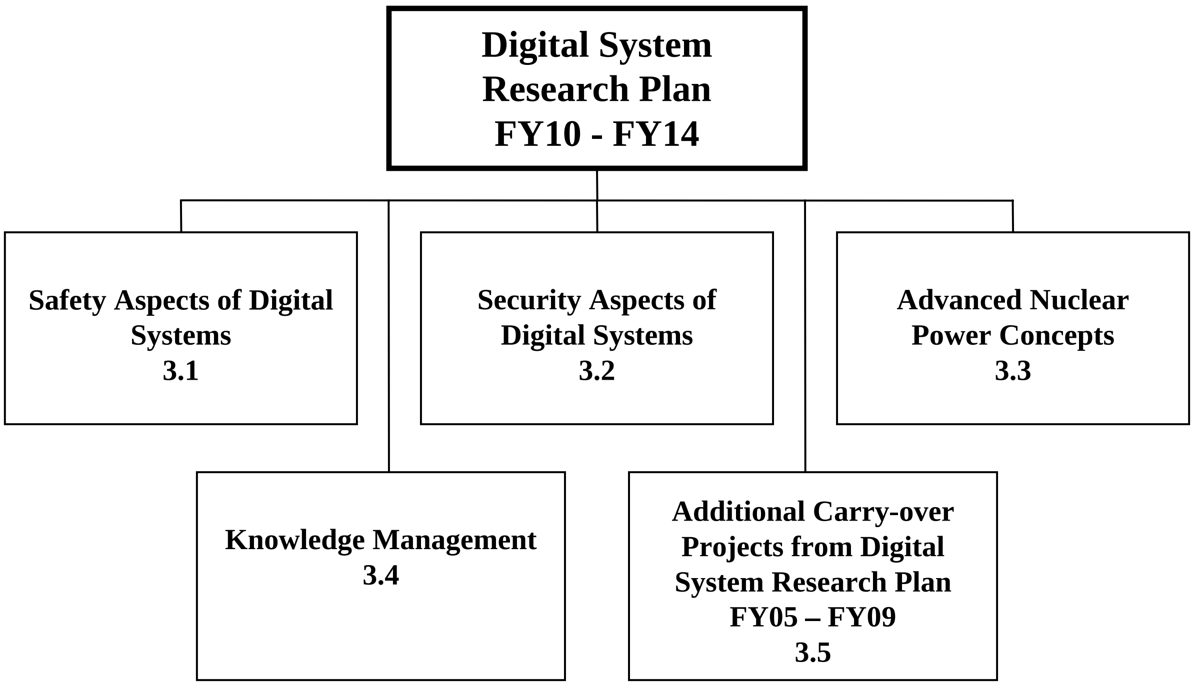
Digital System Research Plan FY10- FY14

- **Collaborative efforts with supported Offices (NRR, NRO, NMSS, NSIR)**
- **Comments, needs, and priorities of the various offices have been incorporated. Comments included**
  - **Include NRC training courses as an optional task for each research project statement of work**
  - **Avoid duplicate efforts, leverage information readily available in the public literature, and encourage industry to take the lead on research topics more applicable to industry (e.g., sustainability and obsolescence management)**

Digital System Research Plan FY10- FY14

- **Comments included, cont.**
  - Continue digital I&C PRA work
  - Evaluate the capabilities and limitations of automated tools used in various life-cycle activities
  - Improve understanding of digital technology failure modes and effects and their analyzes
  - Provide specific deliverables
    - Staff guidance, acceptance criteria, tools and methods, review procedures, training curricula

Research Programs



Safety Aspects of Digital Systems

- **Communications Among Plant-wide systems**
  - In-house effort to develop a generic abstract model of plant-wide digital systems
  - Gain a better understanding of network-based challenges to reliability, redundancy, and independence among systems

- **Safety Assessment of Tool Automated Processes**
  - Develop acceptance criteria regarding the use of tool-assisted or tool-automated engineering activities
  - Effort will leverage existing guidance from other industries

Safety Aspects of Digital Systems

- **Development of Benchmark Reliability Data**
  - Ongoing research implementing UVA fault injection method
  - Develop a testing method to potentially complement regulatory reviews
  - De-emphasizing the estimation of digital system reliability for use in PRA models

- **Diagnostics and Prognostics**
  - Assess the safety impact of these systems and techniques and their impact on equipment operability

Safety Aspects of Digital Systems

- **Integrated Plant & DI&C System Modeling**
  - Develop a simulation-based model of DI&C systems coupled to other plant models and tools
  - Assist reviewers in the validation and characterization of DI&C on reactor safety

- **Digital System PRA**
  - Development of PRA methods, tools, and guidance, if practical, to support:
    - Nuclear plant licensing decisions using information on the risks of digital systems
    - Including models of digital systems into nuclear plant PRAs

Safety Aspects of Digital Systems

- **Analytical Assessment of DI&C Systems**
  - Develop an inventory, classification, and characterization of DI&C systems for use in nuclear safety applications
  - Identification of credible systematic failure and fault modes typical of software-intensive DI&C systems
  - Initial focus is an analysis of 3 pre-approved platforms in highly integrated environment
  - Gain a better understanding of DI&C failure modes and of the feasibility of applying failure analysis in risk quantification

Security Aspects of Digital Systems

- **Security of Digital Platforms**
  - Ongoing project by Sandia National Laboratories
  - Conducting cyber-vulnerability assessments on NRC approved digital platforms
  - Investigate the appropriate elimination and mitigation of potential security hazards

- **Network Security**
  - Ongoing projects by Sandia and Oak Ridge National Labs
  - Develop regulatory guidance discussing wireless and wired network security vulnerabilities and mitigation strategies

Security Aspects of Digital Systems

- **Security Assessments of EM/RF Vulnerabilities**
  - **Ongoing project by Sandia National Laboratories**
  - **Studies in the early ’80s**
  - **The Commission has not specifically identified EM/RF emitting weapons as a credible threat to nuclear stations, however, some limited anticipatory research is considered prudent**
  - **Support a new regulatory position on EM and RF**
  - **Recommendations for potential mitigations, as appropriate**

Advanced Nuclear Power Concepts

- **Advanced Instrumentation**
  - Anticipatory research to analyze the requirements and potential safety issues involved with instrumentation of advanced reactors
  - Different transducers may require different approaches for accuracy assessments and compensation methods

- **Advanced Controls**
  - Anticipatory and exploratory research for increased used of automation, integration, and advanced control algorithms in safety systems

Knowledge Management

- **Survey of Emerging Technologies**
  - **Ongoing and periodic series of reports on emerging capabilities that have potential applicability for safety systems**

- **Collaborative and Cooperative Research**
  - **Other Federal agencies (e.g., NITRD program)**
  - **EPRI MOU**
  - **International collaboration (e.g., COMPSIS database, Halden)**

Knowledge Management

- **Standards Development, Regulatory Guidance, and Review Guidance**
  - Ongoing effort to understand, evaluate, and participate in national and international standards
  - Work will leverage on-going efforts such as the MDEP program and IAEA working groups

- **Organization of Regulatory Guidance Knowledge**
  - Large number of NRC documents and industry standards
  - Develop aids and tools to improve regulatory reviews

Knowledge Management

- **Operating Experience Analysis**
  - **Continue efforts to evaluate the OpE with digital systems in the nuclear industry and other industries to gain insights regarding potential failure modes**
  - **Data from operational experience obtained and analyzed to date have been found to be inadequate and not statistically significant**
  - **In the short term, document insights gained from OpE data reviews. In the longer term, develop a digital component failure parameter database to support PRA research**

Additional Carry-over projects

- **Electromagnetic Compatibility**
  - Industry claims that certain test limits are overly conservative
  - Interact with EPRI via the MOU and update the guidance in Reg Guide 1.180, if necessary

- **Operating Systems**
  - Evaluation criteria for operating systems likely to be used in NPPs
  - Will leverage existing research from other sectors

Additional Carry-over projects

- **Electrical Power Distribution System Interactions with Nuclear Facilities**
  - **Project stems from the 2003 power blackout in the northeast**
  - **Need to address degraded power grid effects and power fluctuations (e.g., overvoltage spikes) on digital components**
  - **Dependencies on power supplies across distributed networks are not well understood**

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Schedule

- The draft plan was made publicly available on July 29th, 2009 and is on NRC's ADAMS under accession number ML082470725
- As of September 2, 2009, the staff had not received any public comments
- Public and stakeholder commenting period until September 20th, 2009
- Plan is to go into formal NRC concurrence (office director concurrence) following incorporation and resolution of all ACRS and public comments

Schedule, cont

- The staff aims to have the research plan published by the end of calendar year 2009
- Working under a MOU between EPRI and RES, the parties intend to use the research plan to help identify areas for potential collaborative research

Summary

- The staff requests that the ACRS endorse the plan and continue to provide inputs on how to improve the research plan
- RES is looking forward to working closely with the ACRS as the research is implemented

Acronyms

- ACRS – Advisory Committee on Reactor Safeguards
- COTS – Commercial Off-The-Shelf
- DI&C – Digital Instrumentation and Controls
- EM- Electromagnetic
- EM/RF – Electromagnetic/Radio Frequency
- EPRI – Electric Power Research Institute
- FPGA – Field Programmable Gate Array
- FY – Fiscal Year
- HF- Human Factors
- I&C – Instrumentation and Controls
- IAEA – International Atomic Energy Agency
- MDEP - Multinational Design Evaluation Programme
- MOU – Memorandum of Understanding

Acronyms, cont

- NITRD - Networking and Information Technology Research and Development
- NMSS – Office of Nuclear Material Safety and Safeguards
- NRC- Nuclear Regulatory Commission
- NRO – Office of New Reactors
- NRR- Office of Reactor Regulation
- NSIR – Office of Nuclear Security and Incident Response
- OpE – Operational Experience
- PRA - Probabilistic risk assessment
- R&D – Research and Development
- THD – Total Harmonic Distortion
- UVA - University of Virginia