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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

PLANT OPERATIONS AND FIRE PROTECTION SUBCOMMITTEE

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TUESDAY

JANUARY 13, 2015

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ROCKVILLE, MARYLAND

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

COMMITTEE MEMBERS:

HAROLD B. RAY, Subcommittee Chairman

RONALD G. BALLINGER, Member

DENNIS C. BLEY, Member

CHARLES H. BROWN, JR. Member

PETER C. RICCARDELLA, Member

MICHAEL T. RYAN, Member

STEPHEN P. SCHULTZ, Member

GORDON R. SKILLMAN, Member

DESIGNATED FEDERAL OFFICIAL:

GIRIJA S. SHUKLA

ALSO PRESENT:

GORDON ARENT, TVA

MICHAEL BOTTORFF, TVA

WILLIAM D. CROUCH, TVA

TREVOR CROPP, BWSC

JEANNE DION, NRR

MICHELE EVANS, NRR

DANIEL FRUMKIN, NRR

BOB HAAG, RII

JAMES HARVEY, TVA

STEVEN HILMES, TVA

FRANK KOONTZ, TVA

DENNIS LUNDY, TVA

TIM LUPOLD, NRR

GARY MAULDIN, TVA

CHARLES MOULTON, NRR

JUSTIN POOLE, NRR

DAVID RAHN, NRR

KEN SEE, NRO

PAUL SIMMONS, TVA

KEVIN WALSH, TVA

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P R O C E E D I N G S

(8:31 a.m.)

CHAIRMAN RAY: The meeting will now come to order. This is a meeting of the Advisory Committee on Reactor Safeguards, Subcommittee on Plant Operations and Fire Protection. I'm Harold Ray, Chairman of the Subcommittee.

Subcommittee members in attendance are Steve Schultz, Dick Skillman, Dennis Bley, Michael Ryan, and Ron Ballinger. We expect to be joined also by Charles Brown and Pete Riccardella.

Girija Shukla of the ACR staff is the Designated Federal Official for this meeting. This meeting will be open to public attendance.

We anticipate this is the final subcommittee on the Watts Bar Nuclear Plan Unit 2 operative license. Watts Bar Nuclear Unit 2 is the second unit of a dual-unit plant in compliance with 10 CFR Part 50, as such, its licensing basis is the same as the current licensing basis of Watts Bar Nuclear Unit 1. However, Watts Bar is unique with respect to the interval between completion and startup of Unit 1 and the completion and startup of Unit 2. And also Unit

2 is unique with regard to having suspended its construction for more than a decade.

In this meeting, we will hear presentations from the NRC staff and the applicant, Tennessee Valley Authority, regarding the status of construction, inspection, and licensing activities related to Watts Bar Unit 2.

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

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

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

And then also a transcript of the meeting is being kept and will be made available as stated in the *Federal Register* notice. Therefore, we request the participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee. The participants should first identify themselves and speak with sufficient clarity and volume so that they may be readily heard.

A telephone bridge line has also been established for this meeting. To preclude interruption of the meeting, the phone will be placed on listen-in mode during the presentations and committee discussions.

Please silence your cell phones during the meeting. We will now proceed and I will call on Michelle for any comments that you may have before Justin begins.

MS. EVANS: Okay, thank you. Good morning. I'm Michele Evans. I am the Director of the Operating -- I'm sorry -- I'm the Director of the Operating Reactor Licensing in Office of the Nuclear Reactor Regulations. So, after three years, I still can't get that title right.

We appreciate the opportunity to brief you today on the details of our review on the Watts Bar Unit 2 Operating License Application. We last met with this subcommittee in June of 2013, with the full ACRS Committee in November of 2013. At that time, the ACRS issued an interim letter which indicated the ACRS review had not identified any issue which ACRS did not expect could be satisfactorily resolved prior to the currently scheduled operating license issuance and it also identified specific items for future review. The intent of our presentation today is to address those items.

Today, the NRC staff will present to you results of our very thorough safety and technical review of the licensee's application. It should be noted that it has been about 18 months since our last detailed presentation to this subcommittee. Significant staff effort has occurred over that time period to conduct our review of numerous licensing items, in addition to those items which we will be discussing with the subcommittee today.

During the course of our review, the staff had frequent communications with the licensee and conducted several on-site audits and numerous conference calls to discuss various aspects of the application. The thoroughness of the review is supported by the fact that we have had routine weekly public meetings with the licensee at which technical concerns were identified, discussed, and resolved. One of the more challenge review areas that you will hear about today is a hydrology review.

Provided we adequately address these items today, we do expect that this subcommittee meeting and presentation of the full committee meeting in February would be our last planned meetings with ACRS on the review of the Watts Bar 2 Operating License Application.

Our licensing review is nearing completion, with only a few open items remaining. Focus of the NRC efforts have continued to shift more to the areas of inspection and testing, which Region II will be discussing in more detail later today.

There is some progress that has been made to date in the licensee's schedule going forward. We are expecting to be able to put forth the Commission vote paper for the operating license this spring. This would support the licensee's current schedule for fuel load.

We would like to thank the ACRS staff who assisted us with preparations for this meeting today and we appreciate the ACRS's willingness to be flexible with normal timelines for receiving information, as we attempted to close out the specific items in which the ACRS has interest.

At this point, I would like to turn over the discussion to our NRR Project Manager, Justin Poole, who will provide an overview of the agenda for the day.

CHAIRMAN RAY: Justin, before you begin,

let me ask Michele to approve something.

In talking about hydrology, we are talking about licensing basis, design basis --

MS. EVANS: Licensing basis.

CHAIRMAN RAY: -- not beyond design basis.

MS. EVANS: Right.

CHAIRMAN RAY: That is important because both issues are in discussion in the Agency these days and we tend to, or at least I intend to not keep that line as clear as I need to. So, I wanted to make that a point on the record here.

If we talk about things that are a part of Fukushima, such as mitigation or beyond design basis and so on, we need to be very clear that we have now gone beyond our OL review and we are discussing something that is in addition to that.

Okay, Justin.

MR. POOLE: Thank you. Thank you, Michele.

The agenda for today's meeting can be seen here on slide 2. TVA will start with an overview of the project status, followed by discussion of those items that were identified in the ACRS interim letter from November 2013, as they are listed there.

Following that, the NRC will make its

presentation on construction status and then the status of the licensing review. This will be followed by our discussion of the staff's review of those items identified by the ACRS and the interim letter from November 2013.

CHAIRMAN RAY: Okay. And I will say that Member Brown will not want to have the cyber discussion or the Eagle 21 discussion until he is able to be with us.

MR. POOLE: Okay, and we can be flexible and move around the portions of the presentation.

And then finally, a summary of the remaining milestones for the project.

So, unless there is any other questions, I will turn it over to TVA to start their presentation.

CHAIRMAN RAY: Any questions from the members? Thank you.

MR. SIMMONS: Good morning. Let me first start by taking an opportunity to express my appreciation for us at TVA Watts Bar to be able to come and present. I would like to start with introductions for the team. I will start with Gordon.

MR. ARENT: I'm Gordon Arent. I'm the Licensing Director for Watts Bar.

MR. WALSH: Kevin Walsh. I'm the Site

Vice President at Watts Bar.

MR. SIMMONS: Paul Simmons. I'm the Vice President for Unit 2 at Watts Bar Startup.

MR. MAULDIN: I'm Gary Mauldin. I'm the Vice President of Nuclear Projects.

MR. SIMMONS: Okay, thank you.

So, if we go to page two of the presentation, our agenda here will cover an overview of where our Watts Bar 2 project is, along with requested topics that will include hydrology, the sand baskets in our final FSAR on our dam permutations; fire protection, specifically around operator manual actions and feasibility; Eagle 21, our two-way communications testing of thermal conductivity degradation, general design criteria 5 and containment recirculation sump will be the topics that we will be prepared to discuss in today's meeting. Slide 3.

Overview of the Watts Bar Unit 2 Project. Our guiding principles are safe and high quality execution of the work. To date, we have executed approximately 31 million man hours' worth of work without a loss time accident and we completed 98 percent of our work on the quality control acceptance rate, which we continue to focus on that for improvement.

We are committed to our design basis

fidelity with Watts Bar Unit 1. That ensures a common design basis between the two operating plants, improvements for how we maintain the plant, and improvements in the area of human performance and how we train our technicians to maintain the plant and more specifically, how we train our operators in training for the safe operation of the plant is benefited by that.

And then last is our systems, structures and components that have been rebuilt, refurbished or replaced. And some examples of those but not inclusive of everything, on the reactor coolant primary side of the plant, we have replaced our reactor coolant pumps; we have refurbished our reactor coolant pump motors; we have replaced safety injection high point vent valves for the consideration of ALARA and dose considerations for our employees in making sure that when those activities have to be done they are being done as low as reasonably achievable.

In our engineering safeguards, we have refurbished our residual heat removal pumps; we have replaced the heat exchangers associated with that system; we have replaced all eight of the safety-related essential wall cooling water pumps, which provide the water from the Tennessee River to our plant, in order to make sure that we are maintaining sufficient cooling for those components that are important for the safe operation of our plant.

Yes, sir?

CHAIRMAN RAY: When you said you replaced the reactor coolant pumps, were you talking about the pressure boundaries that are part of the reactor coolant lube or just the internals or what are we talking about?

MR. SIMMONS: This would have been the internals for the pump, sir.

CHAIRMAN RAY: Thank you.

MR. SIMMONS: Digital upgrades have been done on the secondary side of our plant that are identical to Unit 1, so that we have consistent operation between Unit 1 and Unit 2, specifically in the area of feed water controls for our main feed pumps and feed water reg valves.

And then on the secondary side, we have replaced our moisture separator re-heaters, which ensure that we have a high quality of steam that goes to our turbine. And we have replaced all of the low turbine turbines and we have refurbished the generator for improved margin.

These are just a few of the examples of the things that we have done in this area to ensure that Unit 2 is like Unit 1.

MEMBER SKILLMAN: Paul, please say more about reactor cooling pump internals replacement. Did you change the buckets the size of the rotating assemblies, the volumetric flow?

MR. SIMMONS: No, sir, I did not.

MEMBER SKILLMAN: So, you are where you were before you changed the pump internals in terms of your design flow rate?

MR. SIMMONS: That is correct, sir.

MEMBER SKILLMAN: Thank you.

MEMBER SCHULTZ: Paul, you have mentioned a number of things where you have made changes to provide conformance with Unit 1. What are the differences that remain? Have you got a listing of those and the priorities that would let us know where there might be things that are significant in difference or do you have a list of things that are yet to be done?

MR. SIMMONS: The things that we haven't completed, Mr. Schultz, will be completed as a part of the construction project. A couple of things that are different but they are different because we have upgraded are in the area of our in-core temperature monitoring system. That is a new system that we have installed. Again, the information and the data that our operators received and are utilized in their diagnostics is consistent between Unit 1 and Unit 2. It is just an upgraded system. That is one example of one where we are different.

The other one that is different is associated with -- our rod control system is different in terms of the output. Again, an upgrade in that system but it provides the same information that our operators would use on Unit 1 for diagnosis and knowing where the control rods are but it is an upgraded system.

So, that is a couple of things that are different but we have no intentions on not completing the work set forth for construction so that when we complete it and turn it over to the operating plant, we will have a plant that is like in design and like for our operators and how they operate.

MEMBER SCHULTZ: Thank you.

MR. SIMMONS: Yes, sir.

CHAIRMAN RAY: Do you know if any of these things would have entailed a 50.59 evaluation, had you had an operating license for Unit 2 when you made them? It is a question that may have been --

MR. SIMMONS: I don't know the answer to

that, sir. We can get that information.

CHAIRMAN RAY: It is not essential. I just wondered if you were aware of that.

MR. SIMMONS: No, I don't know the specifics of that. I would be guessing if I offered you an answer and I am not going to do that.

CHAIRMAN RAY: Okay.

MEMBER SKILLMAN: Paul, I would like to ask about the over three million safe working hours. How does that number compare with your data from Sequoyah and from Browns Ferry?

MR. SIMMONS: The 31 million man hours --

MEMBER SKILLMAN: Thirty-one million. Excuse me.

MR. SIMMONS: Yes, sir, the 31 million man hours. I don't know that it would be fair to compare those numbers because of the number of construction workers that we have on the Watts Bar Project, sir, as compared to Sequoyah and Browns Ferry, which are operating plants without the construction mode.

I would say that we are proud of what we have accomplished with our trilateral team that we have, which is comprised of senior sponsorship. I sit on that, along with all of the representatives from the different union organizations that we employ at the

Watts Bar. It is an active organization that spends anywhere from an hour and a half to two hours on a monthly basis looking at trends, looking at issues, taking feedback from the craft through their supervision on things that need to be done to improve the overall safety for this plant.

And while I have been at Watts Bar just for a short period of time, I have been very impressed with that meeting and the engagement that we have with the members of the union organizations that are supporting the safe construction of Unit 2.

MEMBER SKILLMAN: Thank you.

MR. SIMMONS: Okay, moving on in the presentation on page four, you will see the project update. We have completed our primary cold hydrostatic test. I do want to just take a moment to -- that is on the reactor coolant primary side. The significance for me, as a former licensed SRO is that is the second barrier for fission products. So, it was important that we were able to demonstrate that ability for our reactor coolant system to maintain the required pressure. It was a very complicated test that was oversaw by our senior license, who you will hear from later today on other topics but it was executed very well by the station, without any issues. It involved us filling and venting the reactor coolant system and then running all of the reactor coolant pumps to perform sweep events; and then systematically stepping through incremental pressure increases to different plateaus to assess the condition of the piping and the components, to ensure that we met all the ASME code requirements for leakage on that.

And we did achieved a final pressure of 3144 psig for the ASME code test. It was successful. We met our acceptance criteria and we had no issues during the performance of that complex test for the cold hydrostatic.

We have also completed the hydrostatic testing for the steam generators and for the secondary side of the plant and that was equally a challenging test for some terms of the complexity, the amount of piping that was involved that we filled and then warmed with our building heat system, and then systematically stepped through pressure plateaus to ensure that we did not have any leakage that would compromise that system and met the ASME code requirements for that test as well.

So, I am particularly proud of the station and how that was accomplished in a safe manner without any impact or potential impact to the safe operation of Unit 1.

Right now we have forecast loading ice on Unit 2 for February of this year, and we are forecasting our hot functional testing March of this year, and fuel load June of this summer.

On page 5 of the presentation you will see the current status of our licensing status. A final environmental statement has been completed. Our safety evaluation is near completion. There is no Watts Bar Unit 2 specific contention remaining open and we are currently in development of a substantially complete letter enclosure of the remaining licensing measures.

If there is no questions for me at this time, I am going to turn it over to Kevin Walsh.

MR. WALSH: Thanks, Paul. I am Kevin Walsh. I am the Site Vice president at Watts Bar. Talking about the transition to a two-unit site, as a part of the drive in that transition, we have put in place an operating organization that has taken responsibility to safely and efficiently operate two units at Watts Bar.

We have developed and are executing transition plans for each of our departments that go into everything from worker qualifications procedures, surveillances, plant maintenance, training, and monitoring. And we review the performance within those areas every week as a team.

We have established the necessary organization and the processes to ensure safe and reliable operation through structured oversight and through leadership engagement.

Part of that engagement is in Unit 1 managers take shared ownership of the critical milestones on Unit 2. This approach is designed to ensure that we have proper coordination and communication as we progress towards dual-unit operation.

An example of that and Paul described the conduct of the cold hydrostatic testing on the reactor coolant system, the Unit 1 senior license holder provided oversight and guidance to the testing organization during that to ensure high quality execution of that testing.

We have ensured the staffing is at the appropriate level to support a two-unit operation. Today we sit above the staffing level for TVA's standard organization for a two-unit site. In the near future, we will implement a rapid response team to support fuel load and initial operations and we have planned to remain above the standard organizational staffing post-commercial operation. So, at which point we determine it will slowly transition down to a steady state, a two-unit step.

Training has been provided to site personnel in preparation for doing an operation. Our license operator training has been completed and all the testing has been completed as far as license exams and dual-unit licenses have been formally requested.

And to mention TVA corporate, the organization has been providing governance and oversight through structured oversight plans for each of the major functional areas. We have periodic executive review meetings to discuss status and we have also had several status meetings with independent organizations, such as the Nuclear Safety Review Board and the TVA Board of Directors Nuclear Oversight Committee.

Our current plans to conduct the NRC operational readiness assessment are well underway. And in summary, the site is prepared to operate two units safely and reliably, while improving standards each and every day.

And I will turn the presentation over to Gary Mauldin.

CHAIRMAN RAY: In a second. Are there any question?

MEMBER SCHULTZ: With regard to the overstaffing that you now have, what areas is that concentrated in? Are there any areas where that is concentrated or is it across the board, in terms of overstaffing?

MR. WALSH: Yes, sir.

MEMBER SCHULTZ: And can you give me just a sense of -- give us a sense of what is the magnitude of overstaffing at this point?

MR. WALSH: Yes, sir. We are overstaffed in operations and in engineering, primarily to support the engineering rapid response and the turnover activities that are occurring in the plant, the same basic reasons for operations, mostly in the non-licensed operator ranks is where the overstaff is.

MEMBER SCHULTZ: And when you say you are going to carry that forward into operations for some period of time, is that all of it? All of the overstaffing is going to be carried forward? Because you have got a lot of activity ongoing with startup and other related activities over the next several months.

MR. WALSH: Yes, sir, it will be condition-based, as far as allowing staffing levels to get on the trajectory to meet a normal steady state staffing. So clearly, as the unit performs better, we will make a decision based on conditions to possibly ramp back staffing in certain areas. But right now the expectation is that we are fully ready. We have folks that are dedicated to support Unit 2 needs. And as we assure ourselves that we are getting very solid, reliable, safe plant operations, then we will systematically lower that staffing in a very deliberate way.

MEMBER SCHULTZ: When you say the training is complete, is that -- I presume that is beyond operator training. You are talking about the organization in terms of training or engineering, maintenance, operations as well, at this point?

MR. WALSH: Yes, sir.

MEMBER SCHULTZ: It is all done, all completed?

MR. WALSH: Yes, sir.

MEMBER SCHULTZ: Thank you.

CHAIRMAN RAY: When we met a very long time ago now at the site and looked at the schedule for this point in time, it was -- I will put it this way, Unit 2 testing was a real challenge to Unit 1 and there were some concerns expressed at that time but that was way in advance. There has been so many changes now, I have no reason to think that the sequences and the timing that we were looking at then are relevant now.

That now having been said, what is the major impact on Unit 1 of the Unit 2 startup testing program?

MR. WALSH: Sir, the major impact of the Unit 2 on Unit 1 right now is really, I will call it, exercising the organizational muscle to be able to safely manage two units. Through the system turnovers, we are getting the integration of the system engineers, for example, or the operators that are taking ownership of each of the systems and really applying the same basic longstanding principles, monitoring, plan maintenance, as we would had Unit 2 been there all along.

CHAIRMAN RAY: But I am thinking more of testing of shared systems in which Unit 1, because of it being at power, might be affected by the testing of a shared system that is ongoing in Unit 2.

MR. SIMMONS: So, Mr. Ray, let me talk for Mr. Walsh here on this.

So, the testing that you are concerned about that I have reviewed that has the potential for impacting the operating unit is in the engineering safeguards, the Division 1 and Division 2 testing. And that testing is scheduled after we complete our hot functional testing.

We have assembled at this station a team that consists of both currently licensed senior reactor operators, previous licensed senior reactor operators that were involved at Watts Bar during the initial ESF, engineered safeguards testing that was conducted on Unit 1. Was have that expertise. We have captured the lessons learned that we took from the performance of that test back when Unit 1 was first licensed and have factored that into the plans, the schedule, and the risk reviews that are being performed and will continue to be performed up to the point in time where we execute that test to be able to demonstrate for Unit 2 that we meet the requirements for those systems that are common and they are specifically in the area of common bottled power. Our systems that share those components are the once diesel generators, are essential to our cooling water components. Those are the systems that will be affected by that ESF testing that we will be doing after we complete the hot functional testing.

CHAIRMAN RAY: Well, I know we had some debate about what mode Unit 1 should be in and refueling outage schedules and so on relative to completion on

Unit 2. Like I said, that was a long time ago and schedules are very different today, I am sure, than they were then. But that is the area that was of concern at that time was that maybe we ought to wait until you are in a refueling outage to do some of this work on Unit 2 that could possibly affect Unit 1. You are telling me that has been looked at now much more thoroughly, I think.

MR. SIMMONS: Yes, sir and that is one of the major milestone meetings that I participate in with both the construction side and the operating plant side. As Kevin mentioned, the operating plant's ownership for that, Mitch Taggart, is the Work Control Manager for the station. Mitch is a former licensed SRO shift manager at the Sequoyah Nuclear Station and he has had extensive experience in the area of ESF testing in his previous role. So, he is that sponsorship. That coupled with the other expertise that we have from Watts Bar both currently licensed and previously licensed is how we are working through to make sure that the testing can be done in a way that does not impact the safe operation of the unit.

And obviously, if we see something that causes us to have to reevaluate that, we will, because we are not going to do anything in terms of testing that would jeopardize Unit 1.

CHAIRMAN RAY: Well, project schedules are a big source of pressure. We will ask the staff about their view of this as well. I wanted to get your comments. Thank you.

MR. SIMMONS: Yes, sir. If there are no further questions, we will proceed.

MR. MAULDIN: Are there any other questions before I proceed?

So, my name is Gary Mauldin. I am the Vice President of Nuclear Projects. I am here today to discuss what we refer to as hydrology, which is primarily probably maximum flood, PMF mitigation for Watts Bar site.

So, on slide 8, I would like to just briefly go over the current status. First I would say we have rated our hydrologic analysis of PMF to use the industry-accepted HEC-RAS model that was developed by the U.S. Army Corps of Engineers and recognized by the NRC and the Fukushima guys.

CHAIRMAN RAY: Spell out that acronym for the record, will you, just to -- the model name that you gave us?

MR. MAULDIN: It is, I believe it is in our first bullet. Hydrologic Engineering Centers River

Analysis System.

CHAIRMAN RAY: I found it, thank you.

MR. MAULDIN: Thank you. I thought it was in our slide. I'm so used to calling it HEC-RAS. Sorry.

And then so the dams we credited in our PMF simulations have been confirmed to be stable using current industry guidelines. Or we have physically modified those dams to make ensure they meet current stability guidelines.

The stability modifications to the dams are underway and are scheduled to be complete by fuel load of Watts Bar Unit 2.

MEMBER RICCARDELLA: Excuse me. I thought I read that one of the dams, the work was postponed until 2017.

MR. MAULDIN: There is a section -- that is correct. There is a section of Fort Loudoun Dam that continues to have the HESCO barriers. The work associated with that can't be done due to some highway construction that is going on.

So, we will leave those HESCO barriers in place. We will do the maintenance on them to ensure they can fulfill their function and then we will replace them with the current modification when we can have access to that site.

MEMBER RICCARDELLA: I understand. Thank you.

CHAIRMAN RAY: Now all of this, of course, is on the record as far as Unit 2 goes but it would be done for Unit 1 as well.

MR. MAULDIN: Yes, of course. Flooding is a site-wide activity. So, everything I am talking about will apply to Watts Bar 1 and Watts Bar 2.

CHAIRMAN RAY: Is there a question?

MEMBER BROWN: Yes, I had a question. In the paper that was handed out in one of the letters, you talk about these HESCO barriers, they have like a five-year lifetime. And I think I read in there, there was a plan to do something -- I don't know when you installed them, I missed that as I was doing that.

So, does their lifetime expire before you get to this 2017 period to complete the other modifications?

MR. MAULDIN: So, to be clear with regard to the HESCO barriers, they will all be removed. There are thousands of feet of HESCO barriers. They will all be removed except for the 1900 feet at Four Loudoun. The 1900 feet at Fort Loudoun have had the maintenance performed to replace the components that can wear, which is basically the outside of them.

So, yes, sir, we have done that maintenance to ensure that the lifespan will exceed the 2017 time frame.

CHAIRMAN RAY: All right, thank you.

MR. MAULDIN: The structure systems and components required for flood mode at Watts Bar has been protected from flooding or designed for submergence. Our PMF scenarios have been the subject of an numerous meetings with the NRC and numerous webinars. And we have also had two on-site audits. There are currently no open technical issues.

MEMBER SKILLMAN: Gary, let me ask one or two questions on the hydrology. I reviewed this very thoroughly.

This is the NRC's SER. The licensee performed evaluations for five separate scenarios for simultaneous seismic failures; failure at Fontana and Tellico, simultaneously an OBE coincident with half PMF. There are five of these scenarios and they appear to be permutations and combinations. They are not all the same. Some are PMF. Some are OBE. Some are SSE.

What is the basis for selecting that set of scenarios that provides the greatest WSE, water surface elevation for Watts Bar 1 and 2? What is the basis for that?

MR. MAULDIN: What we tried to do was pick the scenarios that would give the worst case. And of course we moved the event, the seismic event around where it fails different dams at different times.

MEMBER SKILLMAN: Different levels.

MR. MAULDIN: And based on having run those scenarios plus what we have done in the past, we have a lot of information from what we have done in the past, the scenario that we chose was the worst case elevation.

Did I answer your question? I mean, I can give you a lot more detail on that.

MEMBER SKILLMAN: You have the punch line, it was the worst case elevation. How thoroughly was that reviewed by the NRC? Maybe I should ask them that. I would be curious the extent to which you feel as though they really ground it down and looked at it.

MR. MAULDIN: I would answer that, too, was we had extensive conversations with them about it. So, I am sure that they understand what we did and why we did it. We also had an independent review done of this.

MEMBER SKILLMAN: Okay, let me ask one or two more questions.

There were changes in the safety factors. It went from 1.0 to 1.52, then 1.52 down to 1.22. Why was that changing?

MR. MAULDIN: These really changed -- the factor of safety for that particular structure was 1.52, originally.

When we submitted the 2012 LAR, we changed our approach to try to clarify what we were doing with factors of safety. We changed it to say the factors of safety would be greater than 1.0. That became a point of confusion. And I think your question indicates that our interaction with the staff clearly indicated that that was a point of confusion.

So, basically, all we did was go back to where we were and say it is 1.52. We didn't ever intend to imply that that factor of safety had changed.

MEMBER SKILLMAN: Okay, one or two more.

It appears to be a minor item but it says TVA no longer assigns a specific time frame for a particular season. For example, the time frame of October 1 to April 15 used to be winter season. TVA now refers to the winter or summer season without referring to a specific time frame. What is that all about?

MR. MAULDIN: In regard to --

MEMBER SKILLMAN: It is they hydraulic basis for the warning system. I don't understand why there is, so far into this licensing activity, a question about what is the summer season and what is the winter season for monitoring, I guess water pumps.

MR. MAULDIN: I'm not sure that I can answer the detailed technical part of that.

CHAIRMAN RAY: It is for selecting the scenarios, the flooding scenarios is what it is for.

MR. MAULDIN: Yes, I have kind of lost context of it.

CHAIRMAN RAY: But the dates that define summer and winter simply, according to what we were given, have been removed and there is more flexibility in doing that.

MR. MAULDIN: I think I do remember that.

CHAIRMAN RAY: Asking why did you do that, I assume it is for more than just Watts Bar 2. It is something that generally applies to the river system.

MEMBER SKILLMAN: Yes, it seems to be the river system.

CHAIRMAN RAY: Yes.

MR. MAULDIN: And that would be correct. Now, again, I can't answer the details behind that. I do know that it was put in there for the purpose of flexibility. I can probably -- I have got some folks here that probably could dig into that a little bit deeper if you would like to.

MEMBER SKILLMAN: To me it is not a particularly important technical question. It is not a safety question. To me, it is admin. I am satisfied. It just seemed to be curious why this rose to an SCRO.

MR. MAULDIN: Okay. In that case, I will be glad to get back with you a little later today.

MEMBER BALLINGER: I have a question. I think we are going to spend a fair amount of time on hydrology.

CHAIRMAN RAY: Okay.

MEMBER BALLINGER: Some of the numbers that are quoted are up to three significant figures, at least. And I am curious as to what is -- and these are complex modeling scenarios you have to deal with. What is the uncertainty on these numbers? I mean if it is 729.0, it is okay; if it is 729.1, it is not okay, so to speak. But does the 0.1 mean anything?

MR. MAULDIN: I think, in my opinion, it is an indication of the degree of accuracy in the model.

MEMBER BALLINGER: That is my question. What is the degree of accuracy in the model?

MR. MAULDIN: And we are comfortable going to the tenth of a foot in the model. There is substantial conservatism in the model. And really, that has been our standard that we have used pretty much throughout.

MEMBER BALLINGER: Well, the Corps of Engineers and the other people that are involved in this, they are modeling to that accuracy as well.

MR. MAULDIN: I wouldn't want to speak for Corps of Engineers. I will say that when we have done our expert reviews of this outside the agency, as well as the consultants that provided for us, this is consistent with the way we have always done that. It is not unusual to be at a tenth of a foot.

MEMBER BALLINGER: Okay. Is there is some document somewhere that says the accuracy of our model is or the uncertainty of our model is and this is the basis upon which that uncertainty estimate is made?

Because there is a lot of history going on here back to like the '50s.

MR. MAULDIN: Yes, I am not aware of a plus or minus certain percentage of accuracy. I will say that we have built substantial conservatism into the model we are using.

So, if the question is around how certain we are that this accurately models or conservatively models the flood elevation that we would get during a PMF event, we are very confident that we will, that we have met that.

MEMBER BALLINGER: Okay, but there is no document that you know of where that assessment has been done, so that you can make that statement?

MR. MAULDIN: I'm not aware of any, no.

MEMBER BALLINGER: Yes, I know, I don't want to get into the precision versus accuracy thing.

MEMBER RYAN: Well, that is what you are talking about.

MEMBER BALLINGER: That is what we are talking about.

MEMBER SCHULTZ: Gary, you brought up the independent review. And since you have, could you describe that in some more details? It was called or at least what was the scope of the independent review and how would you characterize that as providing the additional confidence you were looking for?

MR. MAULDIN: What we did was we hired a consulting firm that is an expert in running the HEC-RAS model. So, they have done the bulk of the modeling work. They then brought in, I believe the individual's name was Lin, Dr. Lin, to do an independent evaluation. He has done a very detailed evaluation, written a report. I am familiar with the report. I have not talked to him personally but we did have some of the folks here that have. And if you would like for them to speak, they can.

But he looked at the details of our model inputs, the outputs, obviously the assumptions that we made. He has also worked with the U.S. Army Corps of Engineers to ensure that we are consistent with industry practice because that is the key point for us. So, those were the key elements that he has looked at. If you want more detail, we have got some folks that can go into that detail.

MEMBER SCHULTZ: That's fine for me. Thank you.

MR. MAULDIN: I would like to move on to slide 9, if everybody is ready to move. This just provides the lay of the land at Watts Bar site. Notice the nuclear power plant in the lower center with the plant grade elevation annotated. Just upstream of Watts Bar Nuclear Plant is Watts Bar Dam in the upper right-hand corner. Watts Bar Dam was built in '42, 1942. It is 112 feet tall. It has got a five-unit powerhouse and a 60 by 360 foot lot.

Where you see the word embankment there, that is where the bulk of the HESCO barriers were installed at Watts Bar. I know we talked about that. We did that as a compensatory measure in the 2009 time frame. Those HESCO barriers at Watts Bar are now all removed.

I would note a couple of elevations. If you compare the winter pool there in the tail water to the plant grade elevation, there is about 46 feet of elevation difference. And if you look at the historical storms we referenced in the lower left-hand portion, you will also see that those are well below plant grade.

MEMBER SCHULTZ: Gary is there a way to take those historical storms and compare them, the storms and the characteristics of them to the assumptions that were used in the PMF analysis?

MR. MAULDIN: Actually, the way we do the hydraulic analysis is we do pick a couple of the large storms and those are the basis. So, we have got the actual data from those storms and we compare that to what the model tells us and that is how we determined that the model is calibrated. And that was done and was also looked at by the staff to ensure that it was done correctly.

So, what you described is exactly the way the process works.

MEMBER SCHULTZ: An element of calibration. And then you described that you, the team that did the evaluation, have imparted then additional conservative input assumptions to the model. You feel very comfortable that those input assumptions are providing conservatism in the evaluation.

MR. MAULDIN: That is correct. And I will go over some of the details a little bit later.

MEMBER SCHULTZ: But when you say you use these as benchmarks in the evaluation to demonstrate conservatism or to set up some sort of, I hate to use the term, but best estimate comparison, how would you characterize it?

MR. MAULDIN: Calibration. I would characterize it as calibration.

So, we know what rainfall, streamflow, et cetera, was during these storm events. We can then model that same event in the model and we can see what we get out. If it is close to the same, then we say the model is calibrated. It is really just that simple.

MEMBER BLEY: Well, let me push you a little on this because I am a little confused now. So, when you do that, if the water level calculations that you come out with match pretty well with the flooding that occurred when you are calibrated, but you are not conservative, matching the previous storm and coming out about where you said where the water would be.

MR. MAULDIN: Okay, I think that is a good question.

MEMBER BLEY: Yes, so which is it, conservative or is it trying to hit the mark?

MR. MAULDIN: It is two different scenarios. So, the conservatism -- when we get a little bit later in here, I will talk about how we modeled some of the dams for stability.

MEMBER BLEY: Okay.

MR. MAULDIN: And let me just go ahead and say, answer this question. When we modeled some of those dams, we did not want to credit for stability. We basically filled the -- so, a completely different scenario than the storm scenario.

MEMBER BLEY: Okay.

MR. MAULDIN: So, we run the storm scenario and we get the same numbers.

MEMBER BLEY: And you calibrated the model.

MR. MAULDIN: Right.

MEMBER BLEY: If it rains, I get rain in the storm, we get the right answer.

MR. MAULDIN: Now, we have got a whole new scenario --

MEMBER BLEY: Okay.

MR. MAULDIN: -- where we are going to start to credit different dams in different ways and we did that scenario in a very conservative fashion. And I will go through the details of that in just a couple of slides, --

MEMBER BLEY: Okay.

MR. MAULDIN: -- if that answers your question now or I can do it now.

MEMBER BLEY: No, that's good.

MR. MAULDIN: Okay.

MEMBER BLEY: That's good.

MR. MAULDIN: Very good. Okay, let's move on. I don't want to completely take up all the time.

This next diagram is just a schematic of the Tennessee River System. It has to get us all grounded on --

MEMBER SCHULTZ: I'm sorry, Gary, I have one question. Somewhere I went to reservoir levels and they are fairly narrow in range. So, you are able to maintain that and this is representative of a spectrum of historical data? In other words, in dry years you still have the water level in the summertime within this range, roughly? Many sites don't have that luxury. I mean a dry year and their reservoir is in difficulty but you don't have that on the river?

MR. MAULDIN: The short answer is yes, we can maintain that. And the reason for that is we are immediately downstream, a mile downstream of a dam. So, as we regulate with that dam, we regulate within reservoir operating guides. And for our river forecasting center as these guides and they ensure that we stay within these ranges.

So, as a matter of fact, yes, we can maintain that.

MEMBER SCHULTZ: Representative of Watts Bar operations?

MR. MAULDIN: Very much.

MEMBER SCHULTZ: Good, thank you.

MEMBER BLEY: As a toast to other parts of the country where the Corps controls the water shed, in Tennessee you guys actually control the water shed. You control the dam. You see the releases and all of that.

MR. MAULDIN: That is correct.

MEMBER BLEY: Okay.

MR. MAULDIN: So, let's move on to slide 11.

We will actually get into the discussion of the flooding scenario. I just want to provide a short background. Most of you are probably familiar with it.

But specifically, we found some issues with the TVA developed hydraulic model that we call SOCH that were discovered during the Bellefonte permitting process and subsequent QA verification of that database. Also, I would say SOCH, because it is a TVA-specific software model, is not an industry-recognized tool.

Also as time has elapsed, the reservoir operating parameters, which I just discussed a second ago, those changed over time. Therefore, some of the underlying assumptions that were previously made were no longer valid. And we also had challenges to dam stability and that was based on the fact that all of that relying on the original documentation for the calculations for those dams and, obviously, the original design that was done in the '40s is not reflective of current industry standards. Next slide, please.

As the result of that, to address those questions in 2012, we submitted an LAR to address most of the issues for Watts Bar Unit 1. So, the TVA SOCH model that I mentioned earlier was revised to correct all of the incorrect inputs and a new PMF level was established, which was 739.2 feet. Part of the basis for this LAR was continue to use the HESCO barriers. We also upgraded the stability of two dams, Cherokee and Douglas and made in-plant modifications to ensure the structure, systems, and components were protected or designed to be submerged.

And we reworked our seismic dam failure scenarios, which we have talked about just a few minutes ago. That yielded a water elevation of 731.2. So, clearly, our seismic case is quite a bit less than our probable maximum flood case.

Warning times were looked at and confirmed --

CHAIRMAN RAY: Is the seismic case at PMF or half PMF?

MR. MAULDIN: There are two seismic cases we look at. One is our operating base earthquake, combined with a half PMF. The other is the safe shutdown earthquake with a 25-year flood. Those are the two seismic scenarios.

Then in April of 2014 we had an NRC audit and during that audit, the NRC challenged dam stability assumptions which, again, were based on the original dam design.

Next slide, please.

So, from that challenge, we have decided that we would move to a PMF scenario better grounded in current industry standards. So, here is what we did with our new model and this is really the key to this conversation. We made two significant changes to the way we were approaching this. One is for our PMF modeling, we moved away from the TVA SOCH model to use the HEC-RAS, too, because it reflects current industry guidelines.

The second major change we made was to move to current industry standards for dam stability review and analysis. Those standards were developed by TVA's river operations group. TVA river operations is the dam authority for the TVA dams. We have, within TVA, adopted the federal guidelines for dam safety. So, they are our dam authority. We turned to them to get these guidelines. I will say that the guidelines that they use are based on FERC and U.S. Army Corps of Engineers information as well.

So, we made those two substantial changes.

And what we did after making those changes is we reran the hydraulic model to get new PMF levels behind all of the dams. So, once we had the new PMF levels, we were able to analyze the stability of those dams. Those dams that we could confirm stable, we credited in the model. There some dams that we felt like we could modify in a fairly expeditious time frame, in order to make them stable using the new criteria and we created this model.

There were some additional dams that we did not believe that we could confirm as stable and we postulated failure for those dams in the model.

And back to the previous question regarding margins, the way we failed those dams is we didn't fail them as normal dam failures. We completely filled the reservoir behind the dam. We then instantaneously and completely postulated failure of that dam. In other words, we, in essence, vaporized that dam out of the river system and moved that wall of water down.

So, that is the way we handled this. We then proceeded forward to design modifications for five additional dams. I think I mentioned that we did have to modify some additional dams. There were substantial modifications that I will discuss later.

So, we designed those modifications. We ran the model with all of the above and we came up with a critical flood elevation of 738.9. We have chosen to retain our licensing basis flood level at 739.2, based on the previous OAR that we submitted in 2012.

CHAIRMAN RAY: That is the quiet surface, still water surface.

MR. MAULDIN: Which we did look at when we run on up -- that is all part of our analysis.

And just a note. We did not revise the seismic portion from the 2012 submittal. Next slide, please.

MEMBER SCHULTZ: Gary, just curiosity. Why did you choose to retain what you had calculated in the past? Why not just update it to the new four significant figures that you have determined here?

MR. MAULDIN: The seismic portion of it?

MEMBER SCHULTZ: No, no, just in terms of the number. You are very close to what you had gotten before but you have got a new methodology. But let's just say it was a new LOCA methodology, which you have also got and you have get a new value, you would update your PCT. Since you have got a new evaluation, new methodology, different answer. Only slightly different but why didn't you go ahead and update to that new value so you had correspondence between the calculated value and the methodology?

MR. MAULDIN: We wanted margin, number one. Not much analytical margin. I believe there is real margin but not a lot of analytical margin.

And the second reason is we had already modified the plant and the dams to support the -- we had already modified the plant to support the 739.2 elevation. So, we just decided to keep it. It really wasn't a highly complex thing.

MEMBER SCHULTZ: So, it corresponds then to physical modifications that have been done that you could tie into that number. So, you would like to retain that rather than -- that relationship rather than -- you feel that is more important than retaining a relationship between the methodology and the calculated value. You have got three pieces and you can tie them together.

MR. MAULDIN: Yes, I'm not sure that I would even go that far. I think the truth of the matter is we were sitting around as a leadership team and said let's just leave it where it is. There is no need to change it. We don't need to change it. We don't want to change it. We are going to leave it the way it is.

MEMBER RICCARDELLA: Even though you

could tolerate something, you would rather have it higher.

MR. MAULDIN: That would be correct.

MEMBER RICCARDELLA: Okay.

MEMBER SCHULTZ: Thank you.

MR. MAULDIN: So, I am now on slide 14. I just want to say that this slide we believe our new approach to both Watts Bar 1 and Watts Bar 2 is acceptable and well-documented. And we are confident in that conclusion because HEC-RAS is the industry standard. Our dam stability has been evaluated with current industry guidelines. And actually our regulatory operations, our Dam Authority performed our stability calculations within their purview.

We made conservative assumptions regarding postulated failures. We have done extensive modifications at five dams and I emphasize that to say we are not relying on a lead analysis to make this okay. We are spending a lot of money and a lot of time and a lot of effort to physically modify these structures so that they will meet all of our requirements.

And then we made modifications at the plant proper.

MEMBER BLEY: Before you go ahead, I want to venture into the area Harold warned us about in the beginning. I think I understand what you have done and why you have done it, and that that is associated with licensing basis.

Now, concern over the last few years about floods being on that amount, kind of two related questions about that. Well, three.

One, is there any paleoflooding information available that you folks have looked at that imply there have ever been, historically, higher floods?

Two, I suspect, because of the way you have got the river dammed up, the water is a lot higher now than it ever was before. Is that true?

And three, given your control of all the dams, if you should get storms that sort of thing that would lead to much more water than was calculated in this calculation, do you have the ability to run water off more quickly, such that you could control those kind of events, thinking beyond what you have done here?

MR. MAULDIN: Gee, there are several questions there. Let me first address the regulation of the river.

Actually the regulation via the system of dams that we have on the Tennessee River very much helps to modulate water levels to a very high degree. So, we are able to move water from protected areas to areas that could be susceptible to flooding a lot more effectively.

So, and then obviously the dam, the system of dams started in the '30s so, we have extensive data. Very extensive data. TVA probably has at least as good a data as anybody in the country. So, we have got a very good history since the river system was regulated of all the storms.

Now, our design basis storm, as far as other information was actually provided to us by the weather service. They are the ones that run the worst possible precipitation, the PMP and they are the ones that give us the storm.

MEMBER BLEY: But they don't associate really a probability with those.

MR. MAULDIN: It is, by definition, not probability.

MEMBER BLEY: Right.

MR. MAULDIN: It is, by definition, the worst. So, if you look at, for example, our thousand-year flood. I mean we can compute based on the data that we have our thousand-year flood. The thousand-year flood does not even get on Watts Bar sites.

MEMBER BLEY: Okay.

MR. MAULDIN: The PMF flood does not get on Watts Bar site. It remains dry during both of those events.

Now, once you get to one the Fukushima scenario, I will say that --

MEMBER BLEY: Think more the Missouri River.

MR. MAULDIN: But I think -- okay. So, our ability to control the river, I have kind of talked about that. I have talked about realistic floods, what we see there.

The dam stability question is sort of the last one that I will address and beyond design-basis scenario. And so to the degree that we were aware and to the degree that we were capable, as we had done these modifications I just mentioned, we tried to incorporate the Fukushima guidelines in that so we have a more robust structure than we would normally have.

MEMBER RICCARDELLA: So, do you think this work would meet the near-term task force 2.1 requirements to reevaluate your seismic and flooding hazard or will you have to redo this again to meet that?

MR. MAULDIN: To the degree -- as I said, to the degree that we can, we have. So, for example, there is a 10,000 return period for seismic and Fukushima guidelines. So, we tried to use that when we modified Cherokee and Douglas.

MEMBER RICCARDELLA: Okay. The new CEUS --

MR. MAULDIN: Yes, sir.

MEMBER RICCARDELLA: -- seismic hazard has been included in these?

MR. MAULDIN: It has been -- it is not necessarily all included in these calculations but when we did the modifications, to the degree we could -- so, specifically for Cherokee and Douglas, when those dams were done, the post-tensioning we did considered those loads, so that we will be able to credit those dams when we get into doing the hazard analysis.

Now, we will need to do, we suspect, additional work done. We haven't completed the hazard analysis yet. I think it is to be completed in mid-March. But based on what we see now, we should be able to credit some of the dams that we did the work on.

MEMBER RICCARDELLA: Has your design-basis spectrum increased significantly as a result of the CEUS work?

MR. MAULDIN: No. The way that whole

system operated was it was moved into the beyond design basis basis as far as the 2.1.

MEMBER RICCARDELLA: I mean just technically, did the seismic ground motions increase significantly?

MR. MAULDIN: The CEUS ground motions do increase. I can't remember by exactly how much.

MEMBER BALLINGER: But the seismic scenario has produced flood levels that were below by ten feet, it looks like or something like that.

MR. MAULDIN: Seven feet.

MEMBER BALLINGER: Seven feet.

MR. MAULDIN: Seven or eight feet, yes.

MEMBER BALLINGER: The probable maximum flood levels. In other words, the seismic events that resulted in dam failures, the water levels for those were below other analyzed situations. And is that also true for 2.1?

MR. MAULDIN: No, 2.1 is a different better volume scenario. So, there is not an apples to apples comparison between PMF and the flooding that we get from the 2.1 analysis.

We also have to assume different combinations. So, it is quite a different analysis.

MEMBER BALLINGER: And that analysis will be done in March.

MR. MAULDIN: That is correct. I have got on slide 15, if we can move to slide 15, just some of the modifications that we made to the dams. I won't go through all of this. I will say that we are quite proud of the work that we have done and we have done a lot of work in a short period of time. And I have got then, following on, several photographs that I have provided of some of the work, just to give you an idea of the breadth and scope, a lot of post-tensioning, additional concrete, things such as on slide 19 you can see the HESCO barriers before they were removed. And behind it is the embankment that we built, which shows you the margin that we added between the top of the HESCOs and the new structures. So, that is just an example. And I am glad to say those HESCO barriers are no longer there.

CHAIRMAN RAY: Well, they weren't doing much good at that point, were they?

MR. MAULDIN: They were not. That is the way we like it. We like them gone.

So, I want to move just to move on to page 21 on open item resolution. There were two items here. The first one was regarding the HESCO barriers. And as I mentioned before, the only place that we are going to have HESCO barriers is that 1900 feet at Port Loundoun.

This particular open item was about seismic qualification. We do not credit those HESCO barriers at Fort Loudoun in our seismic evaluation. So, there is no impact from the HESCOs.

The second open item had to do with the overall hydraulic analysis. And as I mentioned, and as we have talked about most of my session here, we have completely reworked that start to finish and we believe that that one is now behind us. The specific discussion here is about the one change we made to seismic in how we credited Fontana and Tellico. And we provided the technical basis of that, based on just the volume of water for the worst case scenario, which is similar to the question you had.

MEMBER SKILLMAN: May I ask this question, please?

MR. MAULDIN: Yes.

MEMBER SKILLMAN: When you assume, I think the term you used was vaporization, the dam is gone just like that.

MR. MAULDIN: Right.

MEMBER SKILLMAN: Now you have this so many million acre-feet of water behind what was that structure. What is the approximate time dynamic for that mass of water to find its way down? Is this hours, many hours, days? Just a curiosity question.

MR. MAULDIN: I honestly don't know the answer to that. The way these postulated failures went, you are talking about before it gets to Watts Bar proper?

MEMBER SKILLMAN: Yes.

MR. MAULDIN: I could guess but it would be flat out a guess, based on my experience. I do have some folks here that probably could just tell us what that is. And if it is just curiosity --

MEMBER SKILLMAN: Yes, I would just be curious to know. Is it 24 hours, 36 hours?

MR. MAULDIN: Well, let's say from the Melton Hill failure to Watts Bar dam, more or less. Is it three hours, three days?

MEMBER SKILLMAN: A practical number. This is not -- we are to going to --

MR. CROPP: So, my name is Trevor Cropp. I am a TVA contractor. And for instance, the Melton Hill failure is a total vaporization of the dam. And Melton Hill is approximately 50 miles to the plant.

MR. MAULDIN: More or less.

MR. CROPP: Roughly. And that time frame

is probably about 24 hours. And that flood wave attenuates fairly quickly in the system.

MEMBER BLEY: Fairly quickly means five miles or something?

MR. CROPP: In the case of Melton Hill, I don't have the exact particulars.

MEMBER BLEY: Well before the plant.

MR. CROPP: Well before the plant that flood wave. You do see the flood wave but it attenuates greatly.

MEMBER SKILLMAN: Thank you. I was looking just to get an idea. Peripheral vision, just how much time would you have. Thank you.

MR. MAULDIN: And then on slide 22, it is just a conclusion, which I think I have pretty much touched on.

Are there any other questions with regard to hydrology?

CHAIRMAN RAY: Let's just make sure we got everything on this slide. That last bullet, elaborate on that, if you would.

MR. MAULDIN: So, we have some equipment at Watts Bar that had to be protected. So, we built barriers around thermal barrier just for fun. We built barriers around the spent fuel pool cooling time. We have installed some waterproof, watertight doors at the intake pumping station.

We have sealed certain equipment, certain electrical equipment so that it can be submerged.

MEMBER BROWN: How did you seal that?

CHAIRMAN RAY: I mean are you talking about distribution panels?

MR. MAULDIN: No. No, we're talking about usually local instrumentation, by and large. So, it is just sealed usually with rubber gaskets. I have actually, we have got the system engineer here, if you want to talk about the specifics of this, we can do that.

MEMBER BROWN: That's just the lifetime. Are these exposed or are these internal to structures, or which?

MR. MAULDIN: They are internal to structures.

MEMBER BROWN: They are inside. So, the water has to get inside the space of the structure in order to do this.

MR. MAULDIN: That is correct.

MEMBER BROWN: So, the dynamic loading is minimal, other than just water rising. Is that what you are looking at?

MR. MAULDIN: That is correct. We do assume --

MEMBER BROWN: My only comment on that from my Navy experience is depending on rubber seals is over a few years, it gets to be problematic. That's all. A lot of damage. And I don't know how often people open and close doors, if they are covered for access, which typically is where people seal them.

So, that is the only reason I asked the question as to how you do that.

CHAIRMAN RAY: Well, the access required, I think, of most of these barriers is through a doorway in which the panel is normally open or adjacent and can be put in place in advance of the flood condition.

MR. MAULDIN: That is correct.

CHAIRMAN RAY: So, you are not worried about sealing a door that is opening and closing all the time.

MR. MAULDIN: Right.

MEMBER BROWN: But for the panel that is sitting there and if you have the probability of a flood and you come in and put these panels over it.

MR. MAULDIN: Yes. So, for example, one of them is a steel enclosure and the front of it is off. So you can go in and you can perform maintenance on the front. Then during the flood, as part of our flood mode preparation, you go then and install another what I would call a stop log but it is another metal panel with appropriate sealing around it. And that gets bolted in.

CHAIRMAN RAY: Okay, that's procedural, then.

MR. MAULDIN: Yes.

MEMBER BROWN: Is there any inspection of these seals over a period of time and panels sit around not doing anything, if they harden over time, which they will -- are you familiar with the details of the PM program?

MR. MAULDIN: I'm not sure if our system engineer is but certainly we can get that information back to you.

He's nodding his head yes.

MEMBER BROWN: Okay. So, there is some periodic inspection of them. That is all I am looking for.

MR. MAULDIN: Yes, I think the best thing is to let Jim talk.

MR. HARVEY: Hi, I'm Jimmy Harvey. I am the site flooding engineer. And yes, there is a quarterly inspection of all our flood mode tools and equipment. And also a modification just recently took place but there is a five-year PM to replace the seals.

MEMBER BROWN: All right, okay. Just a calibration that's all. Thank you. It's pretty consistent.

CHAIRMAN RAY: Anything else on flooding? We are just on schedule here. We are going to take a break if there is nothing more.

MEMBER BALLINGER: I guess I have one final question and that is a lot of this analysis is very, very conservative in that we can quibble over the uncertainty question. But I guess, have you actually done the best estimate analysis of what would happen, should you get this, probably with maximum precipitation event? In other words, do you have the ability to control the dams ahead of time?

I mean, are these numbers that you are coming up with so outrageously high, compared to what you would actually see in a real scenario where you can see the rain coming down and you say I have to do something? Has that analysis been done?

MR. MAULDIN: We have done some preliminary analysis based on rainfall, probabilities, et cetera, et cetera that would indicate we have substantial margin in the area of feet.

We have not done the creditor. We have not gone back and tried to strip out the conservatisms and rerun the model to see what it would be, if that is your question.

MEMBER BLEY: Well, let me ask one question a little differently.

MEMBER BALLINGER: He's better at asking.

MEMBER BLEY: Instead of what you have analyzed, if you see a really major storm coming that is going to dump a tremendous amount of rain, it looks like the most you have ever seen, what kind of procedures do you have in place? Do you start letting water loose before this thing gets on top of you?

MR. MAULDIN: Okay, thank you for that clarification because that is a simpler answer. And the answer is yes. Our river operations, we have got a 24 by 7 forecasting center that acts as the control room for the river, is the best way to put it. They have got procedures and processes in place. They have got, let me simplify it, operating guys that they ensure they operate within. And they do consider forecasts and if it is necessary to start releasing water in advance of an oncoming precipitation event, that is exactly what we do. That is exactly what they do. I worked in there for a while, so, I take credit for the things that they do.

MEMBER BALLINGER: So, you have actual experience at doing this kind of thing.

MR. MAULDIN: Absolutely. I would say annually. And you know when we talk about things like notification of the power plant, it is not just for flooding. It is for things like fish runs. We do special releases for fish. So, our interaction between the nuclear power and a river operations group is very, very frequent, very well-established. So, this is not particularly new for us.

MEMBER BALLINGER: I have personal experiences with your fish.

MR. MAULDIN: In catching fish, I hope.

(Laughter.)

MR. MAULDIN: All right, that is even better!

CHAIRMAN RAY: Have we gotten to the end of the questions that we want to have on the record here? If we have, we will adjourn and reconvene at ten o'clock -- not adjourn. We will recess. Excuse me.

(Whereupon, the above-entitled matter went off the record at 9:47 a.m. and resumed at 10:00 a.m.)

CHAIRMAN RAY: We'll return to the record.

The next item on the agenda for us here is TVA's discussion of the open question, it wasn't an open item in the SER but the question that we had requested briefing on and that has to do with fire protection and operator manual actions associated therewith.

So, who is going to take the lead here?

MR. CROUCH: My name is Bill Crouch. I am Watts Bar Unit 2 Mechanical Nuclear Engineering Manager.

MR. BOTTORFF: And I am Michael Bottorff, Senior License at Watts Bar.

MR. CROUCH: When we were last here talking to you, we talked about fire protection and operator manual actions. And as part of your letter, you requested some clarification and confirmation that, first of all, we are fulfilling and following the guidance of Reg Guide 1.189 and we are utilizing NUREG-1852 in the evaluation of the feasibility and reliability of the operator manual actions.

In your letter, you expressed some desire to have some additional discussion regarding the timelines and methods, particularly related to the topics that are listed there at the bottom of the slide. So, our presentation this morning will discuss these as we go over the overall process. Next slide, please.

With regards to fire detection, at Watts Bar most areas of the plant have what is called cross zone fire detection. This means that I have two different, diverse means of detecting the fire in each room. So, if a fire occurred, the smoke is detected by the two means. It alarms in the main control room and it is confirmed because it is two different devices giving you that. It is not a possibility of just a single failure indicating a device.

So, for those type of fire locations, there is no delay in confirming that I have a fire. There are a few areas that have single zone detection. In this case, in order to confirm that you have a fire, we actually would dispatch operators out to go visually verify that a fire exists. Those locations are very, very close to the main control room such that verification could be performed in just two or three minutes. And the delay time that it would take to go out and confirm that the fire existed is added into our feasibility and reliability evaluations so that we either know about a fire with no delay or we have accounted for the delay.

There are other means of detecting fires, obviously, also. If a fire is reported by plant personnel, there would be no delay because you have got direct confirmation from the person. You could also have an initiation of a high pressure fire protection system or you could have a CO2 system initiation. In both cases, you know those fires exist because the detection system is to detect the fire and release the system. Next slide.

MEMBER BLEY: Let me ask you a question because I am sure you are familiar with the incident, and I won't say which plant but it was quite a few years ago, but they had a fire and some had gone out to visually confirm it. And the fire burned for 20 minutes and did quite a bit of damage because there was so much smoke he couldn't see the flames and he refused to confirm that there was actually a fire. Do you give any -- what kind of training do you give people to avoid that sort of situation?

MR. BOTTORFF: Yes, sir. So, we train all of our auxiliary unit operators, the people that are doing watches that are in the field all the time. They have certain tasks analysis for manual operator actions but they are also trained on a response for if we see smoke, then that is immediately reported. Everybody at the site, through our general training just to work at the site, is also experienced to that. But if they see something, they say something. They make an initial report to the main control room.

And then on top of that, if that emergency call comes in, our fire brigade, which is a separate, stand-alone entity at Watts Bar, they receive that same report emergency and they begin their response.

So, we do have backup. Even if someone says well, I can't tell if there is a flame, that incident is reported to the main control room and we respond accordingly.

MEMBER BLEY: Okay, so you get somebody else out to look.

MR. BOTTORFF: Yes, sir.

MEMBER BLEY: And that was a crazy one to me but it was a significant event at the time. It burned for quite a while. Go ahead.

MR. CROUCH: Next slide. During the last meeting and through follow-up discussions, it was stated that there was a couple of fire scenarios which you would like some more indication or more information about. In particular, the question came what if you had a slow fire or a very small fire that went undetected, would it be capable of disabling your fire safe shutdown equipment before the operations people actually responded to it.

When you look at the administrative and

engineering controls that we have in place, they are put there specifically for the purposes of either minimizing the potential for fire or for ensuring that we have early detection of the fire. We have a control combustible program, which limits the amount of permanent material that is out in the plant that is combustible. We also have a transient combustible control program such that the people who are out in the plant with combustibles, whether it be a liquid combustible or a solid combustible, there is a permit that has to be in place so that we know exactly where that material is to help prevent us from getting in a situation where you can have a large susceptibility to a fire without the operations people knowing about it.

We also, if there is work going on out in the field, we have what is called the hot work permit program and we establish fire watches if you are out there doing work such as cutting or grinding. It has potential for igniting a fire. There is a very controlled process in place to ensure that that cannot start a fire.

Our fire detection and fire suppression systems are in NFPA code compliance, which helps ensure that the fire is detected rapidly and also would also provide the initial suppression before the fire brigade could respond.

Our equipment out in the plant is separated, using guidance such as Reg Guide 1.75 and Appendix R. The 1.75 guidance is the guidance that is used for separating safety related trains of equipment, so that the equipment physically not in contact with each other, separated by specified distances. You also have the Appendix R separation so that you don't have your two safe shutdown paths can be affected by the same fire.

So with all those controls in place and the detection in place, et cetera, the possibility for a small fire going undetected is minimized and, secondly, since all the equipment is separated like that, it would be very unlikely that a small fire could actually get you in a condition where the plant operations people cannot respond to it using the Appendix R safe shutdown paths.

The other question that was asked was could you have a rapid fire, one that, for example, would instantly engulf an entire room and force you into an Appendix R scenario before you could retrieve the auxiliary unit operators back at the control room to begin their response.

For the scenario like this, there is no

rooms where you have equipment in a location that would be susceptible to this type of scenario, where you have to declare an Appendix R event. In order to do this, you have to have an accelerant present, such as an oil-filled transformer. There are five areas in the plant that have the large oil-filled transformers in them, the shutdown board transformers and there is one area out in the intake pumping station.

For these areas, there is no equipment that would require me to immediately declare an Appendix R event. And if we did declare Appendix R, the first operator manual action is not required for one hour. So, there would be plenty of time to recall the operators back to the control room and then begin the response for those.

MEMBER SKILLMAN: You say just areas where there is an accelerant. How about your electrical cubicles where you have got 4160 breakers and if you have a breaker or a relay fail itself, they will explode. They will blow the front of the cabinet out and they will do lateral damage to what is adjacent to them.

MR. CROUCH: Right.

MEMBER SKILLMAN: Why aren't those considered also?

MR. CROUCH: They, as you said, would do that type of scenario but would not necessarily affect all the equipment in the room, due to the separation under Reg Guide 1.75 and Appendix R, you would not be damaging multiple safe shutdown paths. You would limit the amount of damage due to the separation of the cubicle itself.

MR. BOTTORFF: We would also know based on that scenario, sir, immediately in the main control room, based on our indications, especially if it was electrical. But just based on our room separation, if we did have some kind of an arc flash that you allude to, the outward damage in the arc flash radius, based on the amount of current that we have for a fault has been analyzed. Our equipment is separated that it will not affect the other train.

MEMBER SKILLMAN: Thank you.

MEMBER BROWN: You said you would detect this by the -- I'm trying to understand how the operators would detect an arc fault, a 4160 arc type fault that is contained within the panel and then explodes out the front of the panel to whatever areas are immediately adjacent, whatever the distances are.

And how would they -- what is the indication that they are going to use?

MR. BOTTORFF: Yes, sir. So, the question is how are we going to acknowledge that or see the indication? There is a couple of different ways. If the equipment is running, which is or I am putting it in service, which is the most likely time I would receive an arc flash. I would have that equipment, an annunciator in the main control room that the pump suction, if it is a pump, or something to that effect, I have some kind of an alarm related to that equipment.

I also have those watch standers in the field when I am taking the equipment out of service or placing it in service, where they are constantly roving or it would be picked up in our fire detection as well.

But any one of those, either personnel that are at the scene or based on our alarm in the main control room, we have an alarm response instruction that one of the first steps is to dispatch personnel.

MEMBER BROWN: Okay, I am just relating it to two arc faults that occurred in plants that I have dealt with, where the exciter literally exploded out the side of the panel and there was no one -- one of them nobody was around. The other one, the guy just bent over and it blew out over his head, so he was lucky. But there was no immediate indication. It had to be done verbally. Now, this is a Naval plant but we still have a lot of stuff. And this is the generator, the main power generator, one of the many fire generators in an aircraft carrier. So, that had to be reported manually and that is why it wasn't immediately obvious. I have forgotten the exact operation but the electric plant operator was not immediately aware of that when that occurred. That is why I asked the question.

MR. BOTTORFF: Yes, sir. And understand, I was also on a submarine and we had on the starboard turbine generator the same thing occurred. Well, we could hear it. So, the people could hear it and were in close proximity. But also, as you said, it would be reported verbally via 3911 for the Watts Bar emergency line. And then medical is heard at the fire ops and it is heard in the main control room. So, once again, those personnel would respond, even based off verbal.

MEMBER BROWN: So, you really think -- in the submarines, obviously, people hear stuff. This was an aircraft carrier main machinery room and it was just one of the cases nobody happened to be around when it happened, although they found out relatively quickly but not immediately.

MR. BOTTORFF: Yes, sir.

MEMBER BROWN: All right, go on. Thank

you.

MR. CROUCH: Okay. I will turn it over to Mike to continue on.

MR. BOTTORFF: Yes, sir. As I said, I am the senior license for Watts Bar and I would like to share with you how we respond to a fire scenario at the site on page 26.

So, we have discussed already the main control room diagnostics with either an alarm, so I have an equipment fault. I may get a fault like where a pump is turned off. I have an alarm come in, as Bill stated, the fire system and detection or it could be verbal. But the moment that happens, we dispatch our fire brigade, fire brigade leader and a stand-alone fire team. They are dispatched to the scene and we also dispatched the incident commander, who coordinates with the fire brigade leader. And we will show you more of that on page 28.

But the fire brigade leader and the incident commander coordinate the firefighting response. We do recall our auxiliary unit operators to the main control room, as well as the shift technical advisor to the main control room.

We also have operator immediate actions to verify high pressure fire pumps are running and then we are continuously evaluating the plant, if I need to compare an Appendix R situation. And that would be based on plant indications.

We have timed our auxiliary unit operator response to the main control room, based on the conservative locations throughout the plant, based on their watch standing, where they happen to be. And using conservative times, the first two auxiliary unit operators were able to report within five minutes, the first within three minutes. And then for our most remote location that we allow in Appendix R, watcher standard to be would be our intake pumping station and they were able to get to the main control room within eight minutes.

MEMBER SKILLMAN: Does that have any unique clarification? Do they have to be under 175 pounds, run marathons? Do they have to use elevators? Do they have to climb over security fences?

MR. BOTTORFF: No, sir. That was taken into account all the construction that is at the site. It takes into account where they happen to be and it does not include elevators. So, it is taking the stairs to the main control room. And then any of the doors that they would have to go through, including security or any dress that they might have to do coming in or out of the auxiliary building, something to that effect. But that is taken into account, a normal watch standing routine.

MEMBER SKILLMAN: Thank you.

MR. BOTTORFF: Yes, sir. Once those auxiliary unit operators go to the control room, they are then briefed, based on the fire location, on our Appendix R fire safe shutdown appendix. So, we haven't declared an Appendix R fire yet but the auxiliary unit operators are briefed on their location and their actions, should we declare an Appendix R. Next slide, please.

For our operator performance times we do start the time for their actions once we trip the reactor. So, based on our indications, the unit supervisor and the shift manager will declare an Appendix R fire and we will use our abnormal operating instruction to guide us. But that is when we would trip the reactor and we declare and Appendix R fire.

The first auxiliary unit operator who is in the main control room, that is the person directed to perform the manual actions with the shortest amount of time.

So, at the beginning of shift, we do designate auxiliary unit operators for Appendix R positions. However, as they are recalled to the main control room, as they get there, the first operator is briefed on the shortest actions and that is what they will do.

All those actions are proceduralized. So, there is no diagnostics for the unit operators, once they got to the field. They have been briefed, they go to the field, they take the action. They don't have to look at the equipment. They don't have to listen to speakers. They take their actions as directed from the main control room. We have demonstrated those times with walkdowns and we also have taken into account environmental conditions and that is on another slide. Page 28, please.

This slide shows our leadership and oversight, which does include a dedicated fire brigade to combat a fire safely and effectively. At the top is the shift manager. He retains overall command and control of the main control room. Off to the left, you will see the shift technical advisor. As I said, he reports to the main control room, once we announce that there is a plant fire or a casualty. He has independent oversight. So, it is just a separate command and control.

The two unit supervisors, they are

analyzing the plant and all indications, along with the control room operators, based on the fire and whether I have to declare an Appendix R fire or not.

The control room operators also brief the auxiliary unit operators on their actions, should I declare an Appendix R fire.

Off to the right, you see the incident commander and the fire brigade leader. They are at the scene and they are coordinating firefighting efforts with the fire brigade.

And then below there, you see the auxiliary unit operators. They are trained and proficient in their manual actions. As I said, they report to the main control room, they are briefed on their actions and they are standing by, then, based on whether we declare an Appendix R fire or not.

We do run quarterly fire drills to ensure that all the crews are able to demonstrate and combat a fire scenario. And we do have the proper oversight and leadership in place to ensure safe shutdown of the plant, based on the main control room staffing and training.

MEMBER SKILLMAN: Mike, please speak to us for a minute about the relationship between what you show here and your emergency plan. Does a fire gets you into an unusual event or does it take you to an alert? And is there any event right in the front end that will take you to a site?

MR. BOTTORFF: I can't think of one off the top that would take me to a site unless I experienced where I couldn't trip the reactor. However, we do start off with, normally, an unusual event, which would go to an alert. All the shift managers are trained that if I declare an unusual event by our emergency procedures, we do not have to staff, have external staffing with our technical support and operations support centers. However, we are all trained if I am declaring an unusual event because of a fire or some other kind of damage to the plant where I am going to need the assistance, that we do use that option in our procedures to staff the technical center and the ops support center.

MEMBER SKILLMAN: And I am assuming from the tone of this discussion, this is about Watts Bar Units 1 and 2. This is not unique to WBN2.

MR. BOTTORFF: That is correct, sir. This is dual-unit. This is the site. And this is how we train.

MEMBER SKILLMAN: Just to be clear. Thank you.

MR. BOTTORFF: Yes, sir.

MEMBER SKILLMAN: Got you.

MR. BOTTORFF: And I am on page 29, please.

These are some of the environmental considerations I have spoken of earlier that we have taken into account. The lighting, we do have emergency lighting in place to ensure safe transit for the manual actions. And then once they get there, for instance where we have nitrogen stations, we do have emergency lighting at the locations where they take out manual actions.

For smoke, there are no short-term immediate actions, operator manual actions in the fire area. We do have large rooms if they enter that does act as a smoke buffer, where smoke is rising and they are able to take out their actions. And also, our fire plans lay out specific firefighting techniques that basically where we enter would not allow smoke to intrude on where those operator manual actions are taking place. So, that is taken into account.

For the radiation aspect, there are no operator manual actions in high radiation areas and there is also no short-term actions that would require an operator to dress out to go inside of a contaminated zone to complete the actions.

We do not have to worry about noise, whether it is from equipment starting or stopping or plant announcements because the operators in the main control room are briefed ahead of time before I declare the Appendix R fire. They are then dispatched with specific instructions on when to carry out their actions. So, they don't have to go once we said, they don't have to diagnose something else and they don't have to be listening with the noises from either firefighting or the equipment.

With all those taken into account, including our personal protective equipment, our environmental considerations were accounted for with a factor of 2 margin for all Appendix R fires.

MEMBER BLEY: Let me ask you a question there. At the meeting we had more than a year ago, John Stetkar asked a number of questions in this area. We referred to those. The kind of key piece he was getting at when he asked if you followed the guidance in the reg guide and in the NUREG, what he thought had been fairly optimistic in how you did these time lines, that it appeared that you started the time line from the time everybody was assembled and ready to go in the control room until the action was carried out.

Where he talked about there is a time to determine that the fire exists and a time to assemble people and then communication, that he couldn't find that you had accounted for. Are you going to get to that?

MR. CROUCH: That is part of what we talked about earlier with the scenarios, the slow scenarios and the fast scenarios.

MEMBER BLEY: And you just kind of said you don't think there can be a slow scenario.

MR. CROUCH: But for the fast scenario is the one that he was concerned about do you have time built in for the automatic recall that happened, to get the AUOs back. And that is what we have demonstrated, that we can get the AUOs back in a very short time frame, three to eight minutes. And then for those rooms where you can be forced into Appendix R rapidly, we can add that recall time in and we still have lots of margin because the first OMA is not required for one hour of those rooms.

MR. BOTTORFF: The other part of that, sir, I know that there was a lot of discussion about when we say time zero is and things like that and it is part of the question that you asked, is yes, sir, that is taken into account.

We are diagnosing the plant based on the fire that comes in, the report. We do start the recall immediately. And based on our indications, if I have to declare an Appendix R fire, I am not waiting on auxiliary unit operators to come to the control room. We then enter our procedure for an Appendix R fire. That declaration is made and that time begins. But that does take into account, then, the three to five minutes for the auxiliary unit operators to come to the main control room to be briefed. They are trained. We have walked these down. The procedures aren't new. So, they understand. They get their actions and then they are dispatched. We still need a factor of 2 margin. We still have conservatism built in there, even with that time coming in. The reason why we say time zero is it is consistent across the crews. When I am over doing evaluations, everybody starts at the same time.

But the bottom line is, yes, sir, we do take that into account from the time they get there.

MEMBER BLEY: We are going to get to some time lines, I think, here, in a minute. Right? No? I thought there were some in your slide.

MEMBER SCHULTZ: In the staff's slides.

MEMBER BLEY: Oh, it's the staff's slides. Okay.

MR. CROUCH: When we had the discussion last time with Mr. Stetkar, what we did not have at that time was we had not timed the AUO recall times. We had some suppositions that they would be fast but we didn't have any specific data. We now have that data.

We also, at that time, did not have the specific date in front of us. It says for those rooms where you could be forced into Appendix R immediately, we did not realize at that time, we didn't have the data that says the first OMA is one hour.

MEMBER BLEY: Okay. On the other ones, where he was concerned that the fire might take a while to be identified, you have indicated some of the things that helped you identify it quickly but don't guarantee that it is identified within some fixed period of time. Is there an allowance in the analysis for that detection time or is there an assumption that it is always found very, very quickly?

MR. CROUCH: If you were in a slow type fire, like an undetected, if it is that small a fire that you are not even setting off smoke alarms, it would not, probably not be damaging enough equipment that you actually would be forced into Appendix R. So, the plant would be operating in a normal configuration, pumps would be running, switch gear would be energized, et cetera. And eventually, when the operations people detected that, the plant was getting in an unstable condition, then they would declare Appendix R and go forward.

MEMBER BLEY: Okay, does he understand how you have done that?

MR. BOTTORFF: Yes, sir. The long, slow-burning fire that does not affect safe shutdown of a plant would not equate to an Appendix R fire.

MEMBER BLEY: We'll have to think about that but okay. Go ahead.

MEMBER SCHULTZ: Mike, could you elaborate? Before we leave the slide, can you elaborate on the specific plans for the manual actions affected by smoke? I mean you indicate the large rooms provide a smoke buffer. But in a situation where you have got smoke in an area where manual action is needed to be performed, what have you got in place with regard to these specific plans?

MR. BOTTORFF: Yes, sir. The operators are in protective gear that they report to the main control room, then. We also have flashlights and they also have the emergency lighting staged specifically where the operator manual actions are. That is protective equipment, the SCDA is for their breathing protection. But the lighting is staged specifically at the operator manual actions to illuminate that area.

MEMBER BLEY: Thank you.

MR. BOTTORFF: Yes, sir.

CHAIRMAN RAY: I guess being one step back from the questions you have just gotten, what is the fire brigade assumed to do or not do during all of this? We are talking here about operators but you have a dedicated fire brigade, which is certainly a good thing, in my judgment. What are they assumed to do?

MR. BOTTORFF: The fire brigade, sir, they hear the same emergency report they do. And if not, then we declare it and then they hear that emergency report. They respond to the scene as a separate entity with the fire brigade leader who will direct their actions. They have two teams, a primary and a backup team with firefighting efforts. So, the primary team would go in and attack the fire. And then that is based on whether it is an electrical, an oil, whatever the case may be for proper firefighting techniques.

CHAIRMAN RAY: Well, is that tied to any of this that you have just been describing about recalling the operators and instructing the operators and declaring an Appendix R condition, and so on? Is the fire brigade tied to that at all?

MR. BOTTORFF: It is part of our plant response tied to it, sir, but it does not, in any way, hinder the auxiliary unit operator response. It is two separate teams. The fire brigade is a response. They are solely responsible to fighting the fire. That is all.

The incident commander --

CHAIRMAN RAY: But they don't need any permission to fight the fire.

MR. BOTTORFF: That is correct. The guidance with the incident commander with the fire --

MR. SIMMONS: Mr. Ray, one thing I think that will help on this, the incident commander that Mike talked to is an active licensed SRO, whose function it is to make sure that coordination between the firefighting efforts, whatever they may be, are coordinated through the control room with the shift manager to minimize any impact to equipment that is needed to safely shut down the plant.

CHAIRMAN RAY: Is the incident commander a part of the fire brigade in this model we are talking about here?

MR. BOTTORFF: It's the third. The incident commander works for the shift manager and is solely responsible for the safety of the plant while the fire brigade is attacking the fire. The incident commander and the fire brigade leader work hand in hand to coordinate the efforts.

MEMBER BROWN: Well, why don't you go back to slide 28 and you can explain that a little bit better.

MR. BOTTORFF: Yes, sir.

CHAIRMAN RAY: Well, I did see that and I had it in mind in asking my questions but the issues then becomes the fire brigade doesn't operate independently of the fire brigade leader; they have to wait for the fire brigade leader to arrive in the scene?

MR. BOTTORFF: They are dispatched together, sir.

MEMBER SCHULTZ: Where is the incident commander? And you have got a dotted line to the fire brigade. What does that mean?

MR. BOTTORFF: The incident commander, sir, is in the plant at various times. He could be down at our work control center. He could be in the main control room.

MEMBER BROWN: During the fire, during the announcement.

MR. BOTTORFF: I'm sorry. During the fire, the incident commander and the fire brigade leaders set up a command post together.

MEMBER BROWN: They are standing together.

MR. BOTTORFF: Yes, sir. So, they are outside of the scene so that they have full communication. They aren't necessarily in breathing apparatus or protection or that. The fire brigade leader and the incident commander are together at the command post. And the fire brigade leader is directing firefighting efforts. The incident commander is maintaining the responsibility of plan equipment.

So, if they say we need to turn off this pump, and the incident commander says well, that is RHR pump, for example, or the heat removal pump. We may or may not be able to turn that pump off.

MEMBER BROWN: But he can't tell the fire brigade leader what to do. The fire brigade leader has to get that from the shift manager. That is the way you --

MR. BOTTORFF: No, sir, there is a little red line dot that is missing between the incident commander and the fire brigade leader.

MEMBER BLEY: Then you have two people in charge. I'm just fuzzy. I mean you have got a shift manager. I am having a hard time seeing how the incident commander would be giving the fire brigade leader instructions as well as the shift manager, who is coordinating with the auxiliary room operator.

MEMBER BLEY: The incident commander is talking to the control room. In the control room, you have a fire procedure.

MR. BOTTORFF: Yes, sir.

MEMBER BLEY: Somebody in the control room, I am guessing, is locked in on a headset with the incident commander going through the fire procedure. Is that true?

MR. BOTTORFF: Yes, sir. Sir, I can explain that. I apologize for the confusion. And I can use it as an example.

MEMBER BLEY: Okay. And then if you can tie the two guys together, how they coordinate.

MR. BOTTORFF: Yes, sir. In the main control room for a fire, they are going through our abnormal operating instruction. They are taking out actions.

In the plant, the incident commander and the fire brigade leader are at the scene and the fire brigade leader is directing fire-fighting efforts. And I will give you a for instance in the communication.

If they are at our condenser circulating pumps and Unit 1 or Unit 2 is in operation, without those pumps, I would have to trip the unit. So, the fire brigade leader is fighting this fire and it won't go out and he tells the incident commander, we need to secure those pumps. The fire brigade leader may not know what those pumps do but the incident commander does. So, the incident commander would relay that to the main control room that I have to secure our condenser circulating water pumps.

The shift manager, then, and the unit supervisor will say I understand we are going to secure these, they will then take the plant actions, which include tripping the turbine, tripping the reactor, potentially, based on the communication between the response from the incident commander and the main control room.

The incident commander is not directing the fire brigade. There is communication between them of the plant effect -- the effect of the plant.

CHAIRMAN RAY: What is the incident commander doing when there is no incident? It can't be a full-time staffed position, is it?

MR. BOTTORFF: Yes, sir. It is a full-time staffed position at the site. He is a senior reactor operator on shift.

CHAIRMAN RAY: Okay but that is his only

function and responsibility.

MR. BOTTORFF: Yes. Well, he can be on work control. He can accept work orders, sign work on, evaluate plant risk. He is doing normal senior reactor operator duties but once an emergency call comes in, he is the incident commander and stations himself in response.

CHAIRMAN RAY: I understand but he must have some other -- his position must have some other job description or title than incident commander, I would think.

MEMBER BLEY: You said he might be the guy in the work control center, supervising there.

MR. BOTTORFF: Yes, sir.

MEMBER BROWN: You are saying the incident commander is one of his duties, which gets activated when an emergency is declared.

MR. BOTTORFF: Yes, sir. And I want to make sure that it is clarified here that he is not the shift technical advisor. He is not one of the unit supervisors. He is the incident commander.

MEMBER BROWN: He is not a control room watch guy.

MR. BOTTORFF: So, if something comes in, he responds accordingly.

MEMBER SCHULTZ: He is predesignated to wear that hat.

MR. BOTTORFF: Yes, sir.

MEMBER BLEY: In the control room, you need to designate one of the board operators or somebody else to be -- usually what I have seen, in looking at a fire after the fact, is one of the guys in the control room, while the fire procedure was in action, wasn't doing much of anything else, except communicating with, in this case, in your case, it would be the incident commander. Is that right? He is pulled off of the board and he is coordinating the fire, getting instructions from the two supervisors.

MR. BOTTORFF: Yes, sir, that is correct. For each shift, there is a control room operator designated, the operator at the controls, to operate for the main control room. The other one is we call a control room operator, who do briefings and respond to equipment discussions.

MEMBER BLEY: Is he also a trained firefighter?

MR. BOTTORFF: I have a few that are but that is not normal --

MEMBER BLEY: It is not a requirement.

MR. BOTTORFF: Yes, sir.

MEMBER BLEY: But I think where we have all been coming from, if the control room says keep that pump running as long as you can, that takes precedent over what the fire brigade leader wants to do.

MR. BOTTORFF: Yes, sir, that is correct.

MEMBER BLEY: Okay. Situational control is still in the control room.

MEMBER BROWN: No, I understand that. It is just it seems to be -- the guy says I have got to have those off in order to effectively fight the fire. And the other guy says no, you can't turn those off. I mean somebody has got to make -- be able to give a director order to do A or B, whichever case it may be. And I am just wondering who that is. Is that the shift manager?

MR. BOTTORFF: Yes, sir, that is the shift manager.

MEMBER BROWN: Okay, that is fine. As long as there is somebody that can tell somebody -- to override. That is all I was looking for when I saw these nine little dotted lines and other stuff.

MR. BOTTORFF: Yes, sir, I apologize. The shift manager does retain overall command and control for the main control room and the scene.

MEMBER BROWN: Okay, so if there is a

difference of opinion of what is needed, he can say do X or do Y.

MR. BOTTORFF: That is his job, yes, sir.

MEMBER BROWN: All right. I think you and I were on the same page.

MEMBER BLEY: Yes, I think so.

MEMBER BROWN: Okay, thank you.

MR. BOTTORFF: I apologize for that confusion. I am on page 30.

We discussed some of the communications that we have put in place now. This is the response. We do have two physically separated radio systems, so a single failure would not prevent communications. And we have verified that the radios will work and support all required operator manual action communications.

MEMBER BLEY: You don't have any sun-powered phones or wired systems? I mean I can think of a single failure that might create a lot of noise that would disrupt any radio system.

MR. BOTTORFF: Yes, sir. As a backup, we do have that ability. We do have, excuse me, wired land phones, as well as sun-powered phones. The primary, though, is from the radio.

And once again, you said it there, the

noise and things like that. I can't have noise on there. These are multi-channel secured lines that we have installed at Watts Bar and tested against interference.

And then if you are talking an external noise, once they are briefed and go, I don't have to necessarily have the communication on the way there.

MEMBER BLEY: Not that you would have a welding machine running, but if you have got something arcing and sparking, you have got a whole range of frequencies. You could wipe out a lot of stuff with that.

MR. BOTTORFF: Yes, sir.

MEMBER BLEY: Usually, it doesn't last too long but that is not always true.

MR. BOTTORFF: And at the announcement of the fire, that work will then fire.

MEMBER BLEY: Will almost surely stop.

MR. BOTTORFF: Yes, sir. And then as I said, the coordination, the supervision, the direction, the senior reactor operator and the shift manager, they retain overall coordination in the main control room with the shift manager as the overriding command and authority decisions for what is made.

The incident commander, he does respond to the fire location and we do have a dedicated fire brigade and a fire brigade leader who respond to the scene.

MEMBER BLEY: Is this common across TVA or is this just what you have at Watts Bar?

MR. BOTTORFF: No, it's common to TVA. Page 31.

We have completed multiple dual-unit fire training scenarios with the crews. Our most recent was done for the NRC. The scenario was chosen by the NRC and it was one of the highest risk-significant areas in the plant for dual-unit fire application. The fire did affect both units. We did simulate the main control room actions in our simulators. So, the crews took the actions, they saw that the indications that they would see, based on that fire. The AUOs, our auxiliary unit operators, were briefed and then they did go to there. They simulated the actions but they did go to where their actions would be.

We did demonstrate effective coordination between the main control room and auxiliary unit operators, including communication and timing. And all the performance met NUREG-1852 margin criteria.

And what we have demonstrated is that Watts Bar fire protection program is capable of supporting dual-unit operations.

MEMBER SCHULTZ: What did you learn from the exercise in terms of opportunities for improvement? Were there soft spots that identified some proven opportunities in the demonstration?

MR. BOTTORFF: Yes, sir. One of the first things, and we have stated before, and it kind of went back to training, the first auxiliary unit operators that report to the main control room, they are briefed on the shortest time. It doesn't matter whether they were designated Appendix R, number 1, 2, 3, 4, or 5. It is how they report there and when they are going.

And one of the other key things that we learned with the firefighting, and this was a firefighting effort but we did learn a lesson there, was for the fire brigade leader and his team and the communication, whether they could direct line the site and see him and we had to use firefighting signals or the stuff was communicated over the radio were some of the bigger lessons learned.

MEMBER BLEY: Real fires have a way of not behaving the way we plan for them.

MR. BOTTORFF: Yes, sir.

MEMBER BLEY: Tell me a little bit about how you look at real events that happen around --

currently there are even past events that have happened because some of the fires I=m aware of in plants have led to water getting into places you didn't expect it to cause other problems. All of a sudden the control rooms not only coordinating the fire, which is pretty easy if that is all they are doing, but they suddenly have one or two transients going on on their formerly operating plants and things get very busy, which can screw up this coordination a bit. How do you deal with that?

MR. BOTTORFF: Yes, sir. So, as the senior license holder, I own the training program as well. So, when we have industry lessons learned come into our site, one, that is incorporated into our training. So, we train, we have those almost exact scenarios that the main control room will see. And then we will also have that same training for the auxiliary unit operators while they have to go take manual actions in the field. So, if they had experienced a scaffold build or there was rain or some kind of other environmental impedance, we take that into account in our training and we discuss those actions.

But everything in the industry, we take into our training program as well and we demonstrated or we put the operators through that training so that we learn from their errors or mistakes.

MEMBER BLEY: Never mind. Go ahead. The question doesn't apply to you.

CHAIRMAN RAY: Any other questions concerning the manual operator actions associated with fire protection?

If not, then we will move to a new subject, Eagle 21.

MR. BOTTORFF: Well, I appreciate the time and I would like to turn it over to Steve Hilmes on page 32.

MR. HILMES: Okay. My name is Steven Hilmes and I am electrical and I&C manager for the Watts Bar Unit 2 Project.

I am here to discuss the two open items in SSER 23 to validate the communications from the integrated computer system to the Eagle 21 is not possible.

If you go to slide 33, Eagle 21, itself, is divided into two subsystems. One is the safety-related subsystem and the other is the non-safety-related system, which also handles the communications between it and the integrated computer system. I might ask you to flip over to slide 35 and let me talk for a minute.

So, the way that Eagle ensures that you can't transmit from the non-safety side or the integrated computer system to the safety side is actually by removing the integrated circuits that are required. So, what you have is --

MEMBER BLEY: Physically taking them out of the --

MR. HILMES: They are physically gone. There is nothing in the socket and we have validated that.

MEMBER BLEY: And that is specified on whatever drawings or diagrams to maintain configuration control.

MR. HILMES: Yes, it is specified on the drawings and any work order that would replace the boards validates it against that drawing.

MEMBER BLEY: Okay.

MR. HILMES: So, what we have done is removed the transmit chips from the computer interface and the transmit from the non-safety-related side, which is for testing purposes.

And then the safety side, we have actually removed the receive integrated circuit.

So, what we did in this test was to do a

--

MEMBER BROWN: Are they identical pieces of equipment? You say RXD. I presume they are identical.

MR. HILMES: They are.

MEMBER BROWN: Okay. I'm thinking.

MEMBER BLEY: Just a quick question. Does pulling those things out somehow create problems with the software at all?

MR. HILMES: No, it does not.

MEMBER BLEY: It doesn't hang up looking for things that aren't there?

MR. HILMES: No and I will talk about that in a second.

MEMBER BLEY: Okay, good.

MR. HILMES: It has been fully fact tested with those integrated circuits removed.

MEMBER BROWN: Okay, now I know what question I wanted to ask.

On the receive side, the RXD, that is the receive chip that has been taken out. Right?

MR. HILMES: Yes, sir.

MEMBER BROWN: And on the non-safety-related it is the transmit chip. But those two devices, RXD and TXD are the same, just different chips that are removed.

MR. HILMES: Actually, this part is different. These two are similar cards but they are actually, when you buy them out, they are actually bought out for the specific purpose to use.

MEMBER BROWN: Okay, I am trying to get to the two little boxes.

MR. HILMES: Chips, themselves, yes, they would be identical components. Yes, they would be.

MEMBER BROWN: The big boxes are all identical.

MR. HILMES: No, not quite. This is the same basic part as this part. Okay? However, when we buy them out of stock, these are preconfigured from Westinghouse and this one is configured differently from this one, so it has a different part number.

MEMBER BROWN: Okay. The middle one?

MR. HILMES: So, the middle on is actually a serial or Ethernet converter board. It is a different type of --

MEMBER BROWN: Different than the other two.

MR. HILMES: Than the other two.

MEMBER BROWN: Okay, so obviously, it can't be interchanged.

MR. HILMES: That is correct.

MEMBER BROWN: Whereas, the other two could be.

MR. HILMES: Could be with a little work, you could get there.

MEMBER BROWN: I'm just - erroneous. I am thinking on the maintenance.

MR. HILMES: I understand.

MEMBER BROWN: A guy just can't take one and go plug it -- something else would have to be done in order -- like there was a key on the connector or something that it would not allow you to plug it in. Is that --

MR. HILMES: It is jumpers, configurations on the board. I am not aware of anything on the key.

MEMBER BLEY: Well, it wouldn't. So, I think you guys are saying different things.

Charlie's question is, could I accidently stick the card in the wrong slot. I think your answer is yes but it wouldn't work.

MR. HILMES: Oh. Yes, it wouldn't work because the firmware is specific to this card.

MEMBER BLEY: Okay but the physical connectors are the same. You could put it in, it just wouldn't work.

MR. HILMES: They are multi-bus cards so you could swap them out.

MEMBER BROWN: Okay but when you went to run your test subsequent to that, you would not end up with the correct results.

MR. HILMES: Yes, you would not be able to make it operable.

MEMBER BROWN: Okay, thank you.

MR. HILMES: So, in our testing we did is we took a computer and injected a signal through the normal path that is used for the integrated computer system. This was a targeted attack. It was using its IP address for normal communications and also a broadcast. We basically inserted a data storm, which is just repetitive data asking repetitive sequences, asking for response.

We then went inside into the internal data bus and monitored this point, saw no data traffic. We also went to the receive side of the LCP and saw no traffic.

And then we actually went in and monitored this point, which is the information that is being broadcasted out from the processor and it continued to broadcast out, so it wasn't being interrupted by the data storm.

And we actually went to transmit out of the Ethernet card and it continued to transmit, too. So, even though it was receiving on the receive line, it was still transmitting out and ignored the receive line, totally.

MEMBER BROWN: The solid black line is different from the dotted line from what is --

MR. HILMES: Basically, this is your communication bus over to here. And the reason I dotted it is is essentially it has no traffic. It is really not connected to anything.

MEMBER BROWN: Okay, but the solid line does what? I mean it looks like you are communicating between the two cases.

MR. HILMES: Yes, the solid line is the transmission of data out of the safety-related section to the serial Ethernet converter card and to the TSP data link handler card. So, it is the information that should be going out here and out here. It is purely a transmit signal. It is how we get the test data and so forth out of the safety-related side.

MEMBER BROWN: And TXD with no little note. And then there is a TXD on other side that has the IC removed. That is a transmit only but you don't say that the receive mode has been disconnected.

MR. HILMES: The receive mode --

MEMBER BROWN: No, on the left-hand box.

MR. HILMES: The receive mode, the IC is removed. The integrated circuit is removed. So, this integrated circuit is not physically in the chip holder.

MEMBER BROWN: No, I understand that. On the right-hand side, you had to remove --

MR. HILMES: The transmitter.

MEMBER BROWN: Yes, you had to remove something in order to make that one one-way.

MR. HILMES: That is correct.

MEMBER BROWN: On the left-hand side, you didn't remove anything to make it one-way.

MR. HILMES: The left-hand side we removed the receive. We do want it to transmit out to get to the integrated computer system.

MEMBER BROWN: Okay. So, the TXD thing is the chip itself.

MR. HILMES: That is correct.

MEMBER BROWN: Okay, I missed that. I thought that was a little sub-board of some kind in there. That is the chip.

MR. HILMES: It is the chip.

MEMBER BROWN: And on that left-hand side, the RXD is a chip that is removed.

MR. HILMES: That is correct.

MEMBER BROWN: Okay. All right, I have got that. Thank you.

MR. HILMES: And --

MEMBER BROWN: I'm not finished yet but okay. When you are done, I will ask you my other question. I want you to finish.

MR. HILMES: I am done now, sir, if you have any other questions.

MEMBER BROWN: Yes, I am trying to relate this to -- I'm sorry I spent a lot of time trying to figure out what we did three years ago and I am trying to relate this communication of the Eagle 21 system to -- here is the picture you showed me of the overall. You know you have got firewalls and you have got UCSs or ICSs and then you have got the pads and all that other kind of stuff.

CHAIRMAN RAY: Charlie, for the record, could you reference what you just handed him?

MEMBER BROWN: Yes, that is the presentation that they provided on July the 11th, 2011 or July 9th, whichever day it was that we had the subcommittee meeting.

And let me ask you my question before you try to tell me what the answer is.

I tried to mark stuff on that so that I could do this coherently with you.

MR. HILMES: Yes, sir.

MEMBER BROWN: Or incoherently, whichever way it comes out. There are a bunch of little boxes. Where is the Eagle 21 system on this chart?

MEMBER BLEY: And if you have anything like this in a backup slide that could be popped up here.

MR. HILMES: I do not.

MEMBER BLEY: Okay.

MEMBER BROWN: You have got the SERPES and the SERPES and the Foxboros and the Common Q. Let me just make sure I understand. Unit 1 is on the left of the picture, I think.

MR. HILMES: That is correct.

MEMBER BROWN: And Unit 2 is on the right. Sometimes Unit 2 is different than Unit 1, which I must have missed in the last conversation.

MR. HILMES: Okay.

MEMBER BROWN: There is no Foxboros or anything else on the left-hand side.

MR. HILMES: Actually, since this point in time, Unit 1 has now incorporated the Foxboro and it would be the same now.

MEMBER BROWN: And the Common Q?

MR. HILMES: The Common Q is Unit 2-specific.

MEMBER BROWN: Okay, that's good.

MR. HILMES: So, --

MEMBER BROWN: And those little firewall boxes is what I meant. Are those these?

MR. HILMES: No, this is specifically for Eagle 21. It wasn't shown on here because it didn't really require any additional protection from a cybersecurity standpoint because it was a hardware type boundary. It would be off of this same branch here, where the Common Q is.

MEMBER BROWN: It is on the bottom. So you were doing what I would call the Level 4 --

MR. HILMES: That is correct.

MEMBER BROWN: -- range of area. So, this is strictly an internal communication and whatever other fire walls are in there for these other pieces, they are just software-based fire walls of some kind. Is that for the Foxboro and the SERPES?

MR. HILMES: Yes, for the Foxboros and the SERPES, those are non-safety-related systems. And we use firewalls to protect them, primarily.

MEMBER BROWN: But they are inside the Level 4 boundary.

MR. HILMES: They are in the Level 4 boundary. The Common Q, its 603-compliant boundary is a software type one-way communication.

MEMBER BROWN: But you show that as a data diode.

MR. HILMES: So, we added an additional data diode in front of it to prevent communications with it.

MEMBER BROWN: All right.

MR. HILMES: Okay?

MEMBER BROWN: Although, it will communicate out to the ICS, the process computer.

MR. HILMES: Yes, it will allow transmission out to ICS but not coming in.

MEMBER BROWN: Okay.

MR. HILMES: Along the same lines, and I am not sure if you are familiar but there is an additional barrier down here that is what they call a TAP and it also allows one-way communications but it is not an open-air gap like a data diode is.

MEMBER BLEY: It is some kind of software control.

MEMBER BROWN: No, it is more of a firmware

-- well, I don't want to call it that.

MR. HILMES: It is more of a firmware-type thing. You cannot modify the software externally.

MEMBER BROWN: It is more like an FPGA type. I am just thinking it is burned into the chip. It is not a software variable, --

MR. HILMES: It is not a software variable.

MEMBER BROWN: -- modifiable type thing. You have to change out the piece.

MR. HILMES: Yes.

MEMBER BROWN: We have a TAP shown in one of the other things. I just don't remember the details of it.

MR. HILMES: And then to separate the way the plant is configured, any of the control systems have to -- the only links to other systems is through the integrated computer system. So, you can't get to any safety-related system unless you go through the IC, integrated computer system.

The integrated computer system has a data diode between it and the business cost.

MEMBER BROWN: You are talking about the TAP?

MR. HILMES: Yes.

MEMBER BROWN: Yes, I understand that part.

MR. HILMES: Okay.

MEMBER BROWN: I had a question on that. Is that data diode -- and I may have asked this the last time, it has just been three and a half years, I have forgotten.

MR. HILMES: Yes, sir.

MEMBER BROWN: Is that data diode, how is it configured? Is that a hardware-based --

MR. HILMES: It is hardware-based.

MEMBER BROWN: I mean I don't want to call it analogue but it is a hardware-based that cannot be modified by software from anyplace. You have to go --

MR. HILMES: It physically cannot transmit data to the other side of it because it has a fiber. It only has the fiber connection to allow transmit. So yes, you cannot modify.

MEMBER BROWN: You can't modify. Yes, okay.

MR. HILMES: It is impossible to modify.

MEMBER BROWN: And that is called out. I mean I presume that data diode has the capability, correct me if I am wrong, has the capability in its basic design, its generic form to go both ways.

MR. HILMES: No, it cannot.

MEMBER BROWN: Okay, fine. So, it is configured mechanically, electrically, card configuration, when you buy it, it is bought as a one-way device.

MR. HILMES: Yes.

MEMBER BROWN: And it is hard-wired to be one-way only.

MR. HILMES: Yes, it is.

MEMBER BROWN: Okay and I presume that applies to the Common Q.

MR. HILMES: That also applies to the Common Q. They are the same make and model.

MEMBER BROWN: Okay. I am not going to ever say this is the last question.

I notice I did the little Level 4, 3, and 2 routines. Am I close --

MR. HILMES: Yes, you are.

MEMBER BROWN: In terms of you all's interpretation?

MR. HILMES: This is correct.

MEMBER BROWN: Okay. My point being in all this dissertation here is to make sure I understood the relationship between the testing they did just between safety and non-safety and how it applied to the overall architecture relative to transmitting through the most protected to the next. Those are the three and four are totally protected from the outside world to make sure it was contained within.

MEMBER BLEY: Charlie, it would be helpful to the rest of us and the transcript if you would have your markup of that, take a photocopy and give it to Girija to be attached to the minutes.

MEMBER BROWN: I'm happy to give anybody anything we can have.

MEMBER BLEY: Otherwise, this discussion --

MEMBER BROWN: Well, it is done in pencil and when I tried to copy it, it didn't come out. I think you have got the -- have you got the original? I gave you the original.

All right. My Level 4, 3, and 2 is what you have?

MR. HILMES: Yes.

MEMBER BROWN: So, the point of this whole thing was is the communication that they tested is not the test -- it did not test the Level 3 to Level 2 configuration. I don't think that is necessary, based on the design. I am just recalling the earlier discussion and you are calibrating me again. And the real key was this, where we do have the ability for software and hardware interchange to make sure it was right.

So, if you read the test report, which I did, it was virtually incomprehensible to anybody that didn't know what all the little piece part numbers were, other than they didn't get any of these things on the scope. So, my conclusion is it is okay, if that is what you want.

CHAIRMAN RAY: Any other questions on Eagle 21, two open items?

MEMBER BROWN: No, I'm finished. Thank you very much.

MR. HILMES: You're welcome. And I will turn it over to Frank Koontz.

MR. KOONTZ: I'm Frank Koontz. I am an engineering specialist on Unit 2. I have got the last three special topics that TVA wanted to present that you guys have requested.

The first one I am going to go over is fuel pellet thermal conductivity degradation with burnup. And we have discussed this with the subcommittee at one other point in time. It is a generic industry issue.

The things that I brought up the time we discussed it before was that Watts Bar Unit 2 would be in its first cycle, so it would have a relatively low burnup core for the first cycle, which would minimize the impact of thermal conductivity degradation.

We also had a large peak clad temperature margin in our analysis of record. So, we had plenty of room to accommodate any impacts from thermal conductivity degradation and we had talked to the NRC and they had proposed a license condition at that time to resolve this issue at the first refueling outage for Watts Bar.

Several things have happened since that time. And what I wanted to do was provide you with an update.

So, if you will flip to page 37, just as a background refresher, Watts Bar Unit 2 has a best estimate loss of coolant accident model that is based on the Westinghouse Safety Analysis Codes. We used ASTRUM, which is their best estimate LOCA model. That stands for automated statistical treatment of uncertainty method.

We also used PAD 4, which was their fuel rod performance code. And Watts Bar Unit 2 will load the same robust fuel assemblies in Unit 2 when we startup that we use on Unit 1. So, the two plants are the same as far as fuel goes.

The analysis that was done with that combination of safety tools resulted in a peak clad temperature of 1552 degrees Fahrenheit, which is fairly low, given the regulatory limit of 2200 degrees Fahrenheit.

The NRC issued several information notices. They issued Notice 2009-23 specifically on thermal conductivity degradation and they noted that the vendor safety analyses were potentially non-conservative because it didn't incorporate the effects of thermal conductivity degradation. Some data they had from a fuel study showed that that was an important factor at higher burnups.

They also issued an information notice in 2011 that specifically discussed ASTRUM, which was one of the codes we used and PAD 4, which is also the other code that we used as potentially being non-conservative because PAD 4 didn't incorporate any consideration of TCD.

They also issued letters to the vendors, each of the fuel vendors saying that they need to re-look at their models and take into account thermal conductivity degradation.

We're over on 38. The two things that have happened since we talked the last time is the

Pressurized Water Reactor Owners Group undertook a task to do an estimate of what TCD impacts might be on the fleet. And they did some generic estimates based on plant groupings.

As a result of that, they projected an increase of approximately 175 degrees for the peak clad temperature for a Watts Bar Unit 2-type plant. So, that would have given us a peak clad temperature of 1727 degrees Fahrenheit, which is still less than our 2200 degree limit.

MEMBER SCHULTZ: So, Frank, if would stop right there. As this work was done by Westinghouse and you say there were plant groupings -- I have read your next bullet, so I wanted to ask the question now.

Was it the intent to provide a bounding --

MR. KOONTZ: Yes.

MEMBER SCHULTZ: -- number for the group of plants?

MR. KOONTZ: Yes.

MEMBER SCHULTZ: Okay.

MR. KOONTZ: And you will notice the next one is a little higher and I can tell you what the difference is.

Based on that result, we decided at TVA that for a licensing position, we should go in and do a specific Watts Bar 2 analysis. So, we commissioned Westinghouse to go do that Watts Bar Unit 2-specific analysis and they used ASTRUM again, which is the best estimate LOCA. And then they used a modified version of PAD 4 called PAD 4 with TCD, where they incorporated a TCD model into PAD 4. And that gave us a new peak clad temperature of 1766. Now, that is a little bit higher than the Owners Group number and the reason was is there is two competing effects in these analyses that they do. One is the effect of the burnup on the thermal conductivity degradation, which tends to drive the clad temperatures up. But they have got an offsetting phenomena that they can take credit for, which is a burn down credit for peaking factors. And as you go further and further cycles, the core becomes less peaked over time and that actually offsets some of the thermal conductivity degradation.

So, for Watts Bar Unit 2, they were a little bit conservative in the way they did the Watts Bar specific analysis and they took a little less credit for the peaking factor burn down. So, that is why you see a slight different in results between the two.

The methodology that they used for Watts Bar Unit 2 had been previously applied by another utility, using the same methods, same Westinghouse

Codes for an extended power operate. So, that was approved by the staff. So, that is why we selected that method.

The peak clad temperature is actually shown on the graph there. The red line is actually the peak clad temperature that we report in the FSAR. So, the analysis of record shows the 1766 degrees Fahrenheit. The blue line is a closer nodalization that comes out of COBRATRAC that doesn't account for localized effects on the rods. That is why there is a slight difference there. But that graph is in the Watts Bar FSAR and that is our analysis of record.

MEMBER SCHULTZ: Have you done a reevaluation for Watts Bar Unit 1?

MR. KOONTZ: No, not other than the Owners' Group evaluation.

MEMBER SCHULTZ: Okay, yes.

MR. KOONTZ: That's where they're at on that.

MEMBER SCHULTZ: But you would assume that the peaking factor --

MR. KOONTZ: Would be similar. Well, it may not be because of our new core load. They actually took our new core load. Then, they burned it down --

MEMBER SCHULTZ: Right.

MR. KOONTZ: -- for cycle 2 and burned it down for cycle 3.

MEMBER SCHULTZ: Right. So, you would have, call it a benefit for Unit 1 --

MR. KOONTZ: Right. Right.

MEMBER SCHULTZ: -- that you don't have as they have evaluated it for Unit 2, which is taking into account the new core.

MR. KOONTZ: Right. Yes, as far as I know, on Unit 1 -- and I haven't been following what they have been doing exactly on Unit 1 -- but I think they have reported in their 10 CFR 50.46 report the penalty associated from the analysis. But we periodically have to turn in --

MEMBER SCHULTZ: Your decision to have Westinghouse do a specific analysis was --

MR. KOONTZ: Specifically, related to the licensing of Watts Bar Unit 2.

MEMBER SCHULTZ: Uh-hum.

MR. KOONTZ: We thought that was the best avenue.

MEMBER SCHULTZ: Thank you.

MR. KOONTZ: Uh-hum.

We submitted that to the review of the staff. The staff decided that they wanted to perform an independent audit, which they may describe this afternoon. But they requested a number of things from Westinghouse with respect to proprietary data for the fuel, which we provided.

They performed an audit using FRAPCON, which already has thermoconductivity degradation built into it. That's the code from PNNL in the Northwest.

The NRC decided the results were acceptable and consistent with what we had provided in our licensing submittal and approved the results for the first operating cycle.

Since that time, we have to do periodic 10 CFR 50.46 reports. There was another issue that came up unrelated to TCD, which resulted in a peak clad temperature reduction of 55 degrees. So, our peak clad temperature rackup sheets for Watts Bar a temperature of 1711 degrees Fahrenheit, which still is plenty of margin for the 2200 degrees.

The NRC has proposed continuing carrying this license condition on Unit 2, that we will reanalyze TCD one more time after Westinghouse has submitted a revised PAD code for review and they have approved it.

I checked with Westinghouse today. They said that the PAD5 code has been submitted. It incorporates some other features and improvements, but it does have the TCD built into it. The latest data was used and they expect to get an SER in probably the fall of this year. So, that would be consistent with us rerunning the analysis at the first part of it.

That's all I've got on thermoconductivity degradation, unless you have some questions on it.

CHAIRMAN RAY: Any questions on that topic?

MEMBER SCHULTZ: What was the issue that resulted in the PCT reduction?

MR. KOONTZ: It was related to heat transfer multiplier uncertainty distributions within the code. You know, this is a statistical treatment of how they do this. And they had some particular change they wanted to make related to that. And that actually resulted in a peak clad temperature decrease slightly.

CHAIRMAN RAY: Anything else?

(No response.)

Okay. GSI-191.

MR. KOONTZ: Okay, the second topic. General Design --

CHAIRMAN RAY: All right, GDC-5. Excuse me.

MR. KOONTZ: Yes, that's right.

General Design Criteria 5, this is Open Item 91 in the SER. I have listed the actual 10 CFR regulation here for you that you can read there quickly.

Basically, what it says that in the event of an accident in one unit for a shared safety system, we have to show that you can still have an orderly shutdown and cooldown of the remaining units. If you notice, there's no timeframe mentioned there. It just says an orderly shutdown of the remaining units.

So, this is an issue on shared safety systems. We have a lot of shared safety systems in the plant, HVAC, air. The ones of interest in this particular case are the Essential Raw Cooling Water System, which is our safety-related service water system for Watts Bar, and our Component Cooling System, which is our intermediate heat exchanger.

Next slide, Gordon.

The Design Basis for Watts Bar is that Watts Bar is designed as a hot standby plant. This is an older plant design. Basically, what it says is one unit can be in an accident and the other unit can remain safely in hot standby, which is 350 degrees or above, steaming off the steam generators.

We have the capability, however, to safely handle one unit in an accident and bring the second to cold shutdown within approximately 72 hours. We picked the 72 hours, quite frankly, because it is consistent with Appendix R, since the regulation didn't specify a timeframe. So, we were able to show that we could meet the 72-hour cooldown.

The plant design has eight Essential Raw Cooling Water pumps. Those are shared between two units. There's four train alpha and four train bravo. And that provides cooling to the component cooling water safety-related HVAC, the diesel generators, the containment spray heat exchangers.

We also have a Component Cooling Water System, and that is what you have the big handout for. It is kind of a complicated system. But that is the layout of component cooling, and that provides cooling to the emergency core cooling systems like pump cooling and heat remover and heat exchangers, spent fuel pool heat exchangers.

And some of the features I wanted to point out to you on this, this is Unit 2 on this side; this is Unit 1 over here. We have three component cooling heat exchangers shared between the two units and we have five pumps, five component cooling water pumps down here at the bottom.

The layout is such that this is Unit 2,

train alpha. It feeds Unit 2. This is the bravo train for both units. All three heat exchangers are the same size. The bravo train normally is lightly loaded, but this is the bravo train for both units. And then, this is the alpha train for Unit 1.

The way the pumps are normally lined up for dual-unit operation is these two pumps service this alpha train heat exchanger, the charlie-sierra pump services this heat exchanger, which is the bravo train for both units. And these two pumps down here service the alpha train heat exchanger for Unit 1. And these are actually labeled bravo, charlie, and alpha. It I s a little bit confusing, but that is the layout.

So, the question for GDC-5 is, can we use that system to safely shut down two units? We constructed dual-unit flow models of both the ERCW system and Central Raw Cooling Water System and the Component Cooling Water System. As you can see, there's a lot of pipe there, a lot of valves, a lot of different configurations you could put it in.

So, we did extensive flow modeling. We looked at various combinations events, whether the accident was on Unit 1, the accident was on Unit 2, whether one unit was in hot standby, the other unit was in cold shutdown, just to look at the loads and the flows that would be required to go through the system.

MEMBER BALLINGER: Can I ask a question?

MR. KOONTZ: Yes, sure.

MEMBER BALLINGER: Is it an Aston Plus Model or something like that?

MR. KOONTZ: It's a what?

MEMBER BALLINGER: What kind of model would you use?

MR. KOONTZ: Bill, what is the name of this? MULTIFLO. I'm sorry.

MEMBER BALLINGER: Okay.

MR. KOONTZ: MULTIFLO. It's a flow code similar to FATHOMS or one of the other flow codes.

An example of one of the accident scenarios that was of interest was where we had a loss-of-coolant accident in one unit, and the second unit was progressing to cold shutdown. In fact, what the concern was is that perhaps the second unit had progressed to cold shutdown and had already gone on to RHR and you had an accident in the first unit.

The combination of that, we took a loss of offsite power, which is our design basis. We took a loss of train alpha power to both units as a single failure. We could probably debate as to whether that is really more than a single failure. We took a loss of downstream dam, which is assumed to make the worst case for NPSH for the ERCW pumps. We took an 85-degree river water temperature, which is our tech spec limit. We took the Component Cooling Heat Exchangers at their max fouling, which means they were ready to go to be serviced. We took the Essential Raw Cooling Water and Component Cooling Water Pumps at their minimum performances. So, they have gone through their Section 11 testing and they somehow reached the minimum, and they are ready to have some maintenance performed on them.

And in that case, what it ends up, if you go back to the slide, Gordon, with the pumps, that ends up, since we have lost the train alpha due to power failures, that ends up with this single train here, the bravo train, handling the accident on one unit and the normal shutdown on the other unit, and it can be either direction.

MEMBER BALLINGER: With one pump?

MR. KOONTZ: With one pump, that charlie-sierra pump at the bottom.

MEMBER BALLINGER: Okay.

MR. KOONTZ: Right in the middle.

MEMBER BALLINGER: Yes.

MR. KOONTZ: And this system does have the capability, this pump can service in parallel this heat exchanger or it can be moved over to here manually. The same thing here, this pump can be moved over manually to service that heat exchanger, but we didn't credit that.

MEMBER SKILLMAN: Let me ask this.

MR. KOONTZ: Sure.

MEMBER SKILLMAN: I read the changes in the modified portions of FSAR 112, which is your most recent.

MR. KOONTZ: Uh-hum. It's a little bit confusing. Actually, the new language will complete in FSAR Amendment 113.

MEMBER SKILLMAN: Okay, but let me offer my question --

MR. KOONTZ: Okay.

MEMBER SKILLMAN: -- and then, ask you to respond to it.

In all three cases, the response to confirm that you could meet GDC-5 resulted in a flow rate change of approximately 100 gallons a minute out of 26,500, 26,400 gallons a minute. Why is that change so small?

MR. KOONTZ: I guess I'm not familiar with the --

MEMBER SKILLMAN: In three different

instances --

MR. KOONTZ: Is that ERCW flow?

MEMBER SKILLMAN: No, it's ERCW.

MR. KOONTZ: ERCW flow. Yes.

MEMBER SKILLMAN: So, it is your main heat removal.

MR. KOONTZ: Right. That's the ultimate heat sink --

MEMBER SKILLMAN: Right.

MR. KOONTZ: -- removal.

MEMBER SKILLMAN: So, for meeting your 72 hours with your highest expect temperature, with your minimum pump performances, in order to claim victory on General Design Criteria 5, you adjusted flow rates in three places by only 100 gallons a minute out of 25 to 30 thousand gallons a minute.

MR. KOONTZ: Yes.

MEMBER SKILLMAN: It seems like that is a very, very almost inconsequential change.

MR. KOONTZ: Right. A lot of these flows are already set by the flow balance. So, they are going to these various heat exchangers with certain flows. So, it's not that we've gone in and actually flopped things around here in the valving arrangement or something like that. We are just looking at what the normal flows are through these various headers and where they can go during this accident, and then, looking to see if that will remove the required amount of heat to safe shut down both the accident unit and the non-accident unit.

So, the full model is kind of a steady-state thing. So, it is set up, we have set up the flow balancing on the ERCW. We have set up the flow balancing on the Component Cooling System. So, we know where all these flows are going.

And then, we take a look at that from a heat removal aspect. We do a heat exchanger analysis on the heat exchangers involved and look at the transfer of heat across the system and how much we can get from component cooling over into that ERCW system and basically cool the two units down.

Now what I'm going to get to here in a second is what we learned out of that. It is that, because we were a hot standby plan, because the systems were designed as a hot standby plan, that we have to cool down the non-accident unit for approximately 48 hours before we can add it onto the Component Cooling System. So, there is a load, a time --

MEMBER SKILLMAN: There's a time load issue.

MR. KOONTZ: There's a time load issue, that's correct.

And what we're able to show on slide 44 was that we could cool the accident unit down. Obviously, we can't do anything with that one. We've got to cool it down. It's in an accident mode, a large-break LOCA. You've got to handle it. It's got RHR which feeds into component cooling. It's got containment spray, which feeds into ERCW, as far as cooling heat loads. You've got to handle that one.

The non-accident unit, then, can be brought to cold shutdown with the caveat that we have got to bring it down and decay heat for approximately 48 hours at hot standby, steaming off the steam generators, using aux feedwater. After that point in time -- and, of course, decay heat is coming down on the accident unit also -- we can dump both those loads on component cooling and the ERCW and cool them down.

And if you remember, I said that the hot standby condition was considered a safe shutdown condition for the non-accident unit. That was part of the plant design.

So, the loads are there. You're right, the loads are there. Flows don't change much. But you do have that time delay in bringing the unit down. And that allows the heat to subside a little bit, the decay heat, because it is coming down exponentially.

So, we have revised the FSAR. Some of it is in Amendment 112. The remainder will be in Amendment 113.

The staff had several requests for additional information that we answered. They closed the open item in SSER 27.

Now there is one remaining action item, and that is for a tech spec revision to allow the non-accident unit to return to mode 3 if necessary. If it is already down in mode 5 or mode 4 and we want to go back to mode 3, the current tech spec could prohibit that because it may require, for example, to be in mode 3, that you have two trains of RHR available. But, as part of the accident, we assumed train alpha power was lost on both units. So, it is kind of a Catch-22.

But it is something the non-accident unit would tend to heat up. If we left it on RHR, we would have to starve that RHR a little bit to service the accident unit, and it would heat back up and it would return to mode 3.

So, depending on how long it had cooled down already, if it had already been in cooldown for 24 or 36 hours, then it wouldn't have much time. It would have to go back to be steaming on the steam generator. But we do need to get that decay heat down for the non-accident unit.

And that is basically what the principal issue is on General Design Criteria 5.

MEMBER BLEY: Now, on the non-accident unit, you don't have any requirement for going on to component cooling water at 48 hours, right?

MR. KOONTZ: No.

MEMBER BLEY: You could just stay there indefinitely.

MR. KOONTZ: You could stay there, yes, at hot standby and, then, load it on later.

MEMBER BLEY: Yes. Yes, you can cool that down as --

MR. KOONTZ: As you wish, uh-hum.

MEMBER BLEY: As you wish, yes.

MR. KOONTZ: And like I say, GDC-5 doesn't really give you a timeframe, either. We selected the 72 in agreement with the staff, just because we had some previous precedence with Appendix R at 72 hours. So, that is what was selected.

MEMBER SCHULTZ: Frank, in this evaluation you have mentioned decay heat for both units. Presuming that the characteristics of the decay heat assumptions is as you would assume for accident mode and --

MR. KOONTZ: Yes, for this, we --

MEMBER SCHULTZ: front-loading, and so forth? You mentioned the details associated with fresh core load, and so forth.

MR. KOONTZ: This one was not really considering that we had a fresh core load for Unit 2 like we did in the thermoconductivity degradation issue. This was basically both units had been at full power for a long period of time. They had full decay heat buildup, and then, we had a LOCA in one and we wanted to shut the other unit down.

MEMBER SCHULTZ: And you used a type of decay heat modeling that you would use for accident evaluation --

MR. KOONTZ: Correct, correct.

MEMBER SCHULTZ: -- and analysis? You didn't have to --

MR. KOONTZ: We didn't do anything special with decay heat.

MEMBER SCHULTZ: -- do anything special with that?

MR. KOONTZ: Right.

MEMBER SCHULTZ: Thank you.

MR. KOONTZ: Right.

MEMBER SKILLMAN: I wanted to say thank you to TVA or --

MR. KOONTZ: Well, it's easier to read than that, isn't it?

MEMBER SKILLMAN: Yes, for those of us who wear glasses, this is a whole lot better than the small ones. Thank you.

MR. KOONTZ: All right. Anything else on GDC-5?

(No response.)

All right. The last one we had to talk about was just to give you an update on containment recirculation sump. This was Open Item 59. And I just wanted to go over the sump status with you.

If you go to 47 -- slide 47, I think it is, Gordon -- the strainer design that we selected for Unit 2 is the same one that we selected for Unit 1, very similar in design. It is a stacked pancake figuration. We will see a little picture of it here later on.

But it consists of 23 stacks mounted on a plenum that feeds the original sump. So, this is a plenum view, and this shows the stacks. Some of these are 5-, 6-feet tall.

The original sump was located

approximately right here. So, we constructed the plenum out through this area, a stainless steel plenum, mounted these things on top of it. And then, as the flow comes down the strainers, through the strainers, it then flows across the floor of the plenum down into the emergency sump.

It is physically located in containment under the refueling canal. This is the reactor. These are the four steam generators. This is actually a floor in here. These are the drains from the upper compartment to the lower compartment.

And the strainer is located in this area back here underneath that. So, it is semi-protected from the breaks over here, here, and here, although this is an open flow area right here underneath this canal. It does communicate there. So, that's what it looks like.

It consists of about 4600-feet surface area, square feet of surface area. We went from approximately 200 to 4600, went to a smaller hole size. The hole size for our old strainer used to be around a quarter of an inch. And we did flow module testing at ALION or Alden Labs, and it was acceptable.

Page 48 shows you a picture of this. This was actually preassembled out on the turbine building floor before they stuck it in Unit 1. This is the Unit 1 strainer.

And it shows the pancake configurations. You can see them. They're stacked up there, and then, there's a core tube in the middle. And then, that flows down to a plenum that is underneath.

To point out some features of Watts Bar containment design, we are a low-fiber plant. We use reflective metallic insulation as opposed to NUCON or some of the mass-type insulations. We don't have any min-K, if you're familiar with that. That is a fibrous insulation that is used sometimes for thermal. We don't have any 3M fire wrap. We have used that in the past in Unit 1. We're trying to get it all removed, but it is a blanket-type material with a stainless steel backing.

We did analyze various sources of debris. We looked at the unqualified coatings throughout the containment. We looked at the qualified coatings and the zone of influence. So, for each of those breaks that we had up there, you would look at the radius around the break. And anything, even if it was qualified inside that zone of influence, it was assumed it failed.

We did take into account latent debris. Like I say, we are fairly-low fiber design. We don't have much latent debris. We accounted for about 100 pounds of latent debris. That is dust, dirt, all that kind of junk, and 15 pounds of fiber out of that. We did account for 1,000 square feet of tape, tags, labels, things that might be left in containment that might get washed over to the sump screen.

Over on page 49, we did all the analyses the NRC was looking for for Generic Issue 191. We looked at debris generation, the types and quantities. We looked at failure of the metallic insulation, and it gets shredded and it gets transported. We looked at the debris transport. We did a 3-dimensional CFD analysis. It basically told of it was transport.

We looked at the strainer head losses, which turned out to be very low.

CHAIRMAN RAY: Say that last sentence again, please.

MR. KOONTZ: We looked at the debris transport in a 3-dimensional computational fluid dynamics model. So, we spent a lot of money basically to see if much of the debris would transport around containment to the sump and learned that, yes, it would transport around to the sump.

CHAIRMAN RAY: Okay. Well, in doing this, I thought it was a result of that particular piece of the analysis you reduced the blockage of the strainer of this latent debris and the things you just mentioned from 700-plus square feet down to 200. What was the basis for that?

MR. KOONTZ: You're talking about the latent debris? We used to --

CHAIRMAN RAY: I'm talking about the tags and --

MR. KOONTZ: Oh, okay. The tape, tags, and labels we assumed 1,000 square foot. And then, the guidelines, the NEI guidelines, allow you to take a reduction to 750 square feet when you do that. And that is assuming that they don't all go next to each other; they kind of lay on each other sometimes.

CHAIRMAN RAY: So, I'm mistaken about this 200 square feet, am I?

MR. KOONTZ: Well, I don't remember the 200 square feet, but at one time we assumed 200 pounds of latent debris, and we reduced it to 100. Actually, we went out there, and Unit 1 we walked it down. We took swipes on all of the surfaces in Unit 1. We weighed them before; we weighed them after. And then, we estimated -- yes, believe it or not -- we estimated the latent debris based on the containment claims in Unit 1.

CHAIRMAN RAY: Okay. Well, I don't want to hold things up now, but I guess the edge effect on these things is the issue, those labels and tapes and stuff, how much of a blockage do they result in. But we don't need to worry about that if you're still using 700-plus square feet.

MR. KOONTZ: Yes, 700 square feet is what we allowed for in the analysis. These things are actually perforated metal plates --

CHAIRMAN RAY: Right.

MR. KOONTZ: -- across here, across this whole surface. This edge has a thickness to it, and it is actually a perforated metal plate. And then, the bottom of the strainer also is a perforated metal plate. So, the flow actually goes in through these perforations --

CHAIRMAN RAY: Right.

MR. KOONTZ: -- comes over to this core tube, and then, flows down.

CHAIRMAN RAY: Right. But, if you've got a tape that is impinging on the side of that stack --

MR. KOONTZ: Right.

CHAIRMAN RAY: -- it can have an effect much greater than the size of the tape itself.

MR. KOONTZ: Right. If you had like a

piece of tape or a piece of paper that came up here and impinged on there --

CHAIRMAN RAY: Yes, right.

MR. KOONTZ: -- then the flow would have to just go around and go into these other areas.

So, we did look at the test results to look at what the dirty strainers would look like as far as flow loss, head loss through the dirty strainers, and we looked at the clean strainer head loss. And even with these things, a lot of coating chips and a lot of different kinds of quantities of debris on them, we only saw about a 1-foot head loss through these strainers. They are prototypical flow rates. That was done at the testing facility.

CHAIRMAN RAY: Okay. Somehow I got the impression that the tapes and labels and things had an attributed effect, 700 plus, that was reduced based on the testing that you referred to.

MR. KOONTZ: No.

CHAIRMAN RAY: That's not correct?

MR. KOONTZ: No. Unless you can show me what you're looking at, I guess I'm just not --

CHAIRMAN RAY: Well, I can't right now, no.

MR. KOONTZ: Yes. I don't recall what

you're discussing, but --

CHAIRMAN RAY: All right. Well, we may ask you to revisit that briefly --

MR. KOONTZ: Okay.

CHAIRMAN RAY: -- at the full Committee meeting.

MR. KOONTZ: We can take a look at that.

CHAIRMAN RAY: Go back and look at it, yes.

MR. KOONTZ: Okay. So, really, what you're worried about is the effect of the tape, tags, and labels and what that did to the strainer coverage?

CHAIRMAN RAY: Right. What is the effective --

MR. KOONTZ: Out of the 4200 square feet --

CHAIRMAN RAY: -- impact of that, given the design that you have here?

MR. KOONTZ: Okay.

CHAIRMAN RAY: Because, I mean, you wouldn't imagine that this would happen, but if you wrapped a tape around --

MR. KOONTZ: Uh-hum.

CHAIRMAN RAY: -- the thing, the area of the tape would be small relative to the total flow area that would be blocked as a result of edge --

MR. KOONTZ: Right.

CHAIRMAN RAY: -- the entry point being blocked.

MR. KOONTZ: Most of these labels we have are little lamacoid labels that just identify things.

CHAIRMAN RAY: Yes. Well, that's maybe why I thought it was due to the testing that you had done, but that's not the case.

MR. KOONTZ: I'll take a look at that.

CHAIRMAN RAY: Okay.

MR. KOONTZ: As I mentioned, we looked at the strainer head losses, very low. We looked at the chemical effects using Westinghouse methodology. We didn't see anything there that was of particular interest, and staff agreed.

We looked at the downstream effects using the approved Westinghouse methods. It looked at orifice erosions. It looked at the impacts of particulates on pumps, valves, and the fuel.

We used the LOCA deposition model to predict the impact on fuel temperatures and the performance of the core. We were well within the criteria there.

We sent the information to the staff. They reviewed it. They concluded that we had done everything that was necessary. They agreed with our results.

The remaining open issues is we have to go in after we finish construction, do a final accounting of the coating mass, and we are doing walkdowns to do that right now. We do a final walkdown for latent debris and cleanliness. This will be toward completion of the plan. After it is cleaned up and we are ready to start the plant up, we will go in and do these swipes and walkdowns.

And we have to install the strainer modules. They are one of the last things that will be put in, just so they don't get damaged during the construction. So, they have to be put in yet.

That's really all I've got on the recirc sump.

CHAIRMAN RAY: All right. Any other questions other than the one that I posed?

(No response.)

Okay.

MR. KOONTZ: That concludes everything that we've got, Gordon. That is correct.

CHAIRMAN RAY: Yes, I believe it does. I'm sure you will be around this afternoon, however. Am I correct in that?

MR. KOONTZ: Yes, sir.

CHAIRMAN RAY: Thank you very much.

MR. KOONTZ: Uh-hum.

CHAIRMAN RAY: So, we are on schedule now and have time set aside for a presentation from the Region.

Greetings.

MR. HAAG: Good morning. Good morning.

My name is Bob Haag. I'm the Branch Chief in Region II in charge of Watts Bar Unit 2 Construction and Inspection Program.

So, this morning I wanted to give you a status of where we are at with our construction inspections. I will talk about some of the preop testing inspections we are doing.

But, on the first slide, I wanted to kind of give you a little of the background. I have said this before, so, hopefully, it is not boring you, and I will go pretty fast through it. But it gives the background as far as, you know, how we established the inspection program for Watts Bar Unit 2.

So, we are using the same inspection programs for Unit 2 that have been used for all the existing plants. Inspection procedures are contained in Inspection Manual Chapters 2512, 2513, and 2514.

2512 deals with construction inspections. 2513 deals with preop testing and operational preparedness inspections. And 2514 deals with startup testing inspections.

Because of the unique history for West Bar Unit 2, including the long delay in construction, we developed a customized inspection program for Unit 2. And this customized inspection program is outlined in Inspection Manual Chapter 2517. It has been pretty much our guiding principle and set of instructions that we have used since construction inspection resumed back in 2008.

We recognize that a substantial amount of the Unit 2 structure systems and components were previously constructed and inspected by the NRC prior to stopping of construction in 1985. So, we went and looked at the status of those inspections and how they stacked up against our inspection procedures to really see what we needed to focus on as far as the Unit 2 construction.

And what we found was that many of the inspection procedures has been satisfied as far as minimum sample size. For example, there is an inspection procedure for concrete structures. We had documented in previous inspection reports where we had completed those inspections and we had satisfied the inspection requirements. So, we factored that information for all the inspection procedures in 2512 as far as what needed to be done specifically for Unit 2 at the resumption of construction.

We also looked at other items that needed to be added to the Unit 2 construction program. And some of those items were the corrective action programs and special programs that TVA instituted to address some of the quality issues from initial construction. We looked at generic communications. Those were bulletins, Generic Letters, and TMI action items that had transpired from the timeframe when construction stopped in the mid-eighties until it was resumed in 2008.

We looked at historical inspection items. Those are some of the items that from our inspection previous we hadn't closed out unresolved items, violations, and things like that. We reviewed construction deficiency reports and historical allegations.

And I kind of say all that, it was factored into the scope of the construction inspection program for Watts Bar Unit 2. And when it was all said and done, we identified and we currently have 553 construction inspection items that we need to complete and close out before we would say our inspection program has been done for Unit 2. I refer to those items as the IP&S database. We have been tracking those. I have given you the status of that program and where we are at previously.

So, again, that is kind of the history and how we developed the construction inspection program for Watts Bar Unit 2.

MEMBER SKILLMAN: Bob, what does that acronym stand for, please?

MR. HAAG: Inspection Planning and Scheduling.

MEMBER SKILLMAN: Okay. Thank you.

MR. HAAG: Now, point of clarification, you really don't schedule with that. In the infancy, it was thought we could do scheduling. It is really just a database for all the inspections we need to do. We track and we close them out, and really it is our roadmap to what we need to do to complete our inspections for Unit 2.

MEMBER SKILLMAN: Okay.

MR. HAAG: And then, I will talk about later on the preop testing and operational preparedness inspections. And I bring that point up right now.

They are not included in that number of 553. We made a decision that the 553 items are mainly dealing with construction inspections. Preop testing and operational preparedness we track differently from that. All said and done, all of it has to be done before the Region would be ready to make a recommendation as far as issuing a license. So, we factor all of that into our scope of what needs to be done, but it is just the terms are different as far as how we track those and some of the numbers that I am going to be giving you later on.

So, Justin, if you can move up one additional slide?

So, this slide we have used before. It kind of gives you an idea of the scope of inspection effort that we have put forward for Unit 2. And I want to make the distinction.

So, you can see for 2014 we made a large spike or increase in the amount of inspection we did for Unit 2. That number corresponds to over 23,000 hours of inspection and inspection support from the region for the Watts Bar 2 project.

That large increase is really driven by three points:

The fact that we did more inspections for the IP&S construction items in 2014 than we had done previously in an effort to go ahead and try to close out many of those items.

We increased the amount of preop testing inspections. Previously, TVA's efforts really had been for preop testing. A lot of it had been on the non-safety systems. So, in 2014, many more items that we were interested in as far as testing of safety-related systems was taking place. So, we really ramped up the amount of inspections we did as far as preop testing inspections.

And also in 2013, the operational preparedness area, for the most part, that is when we started those inspections, and those inspections are done by the Division of Reactor Safety out of Region II, different than the construction organization who had been doing many of the IP&S items.

So, you factor all those additional inspections that we did really caused that number to increase dramatically from what we had been previously doing and somewhat consistent from 2008 to 2013. While it is not exact, it was relatively consistent.

MEMBER SCHULTZ: Bob, you included in your description of the inspection hours onsite and, also, regional support?

MR. HAAG: Yes.

MEMBER SCHULTZ: And can you provide some relationship between what would be the support hours versus, if you will, the onsite hours? And has that been consistent across the chart here year by year?

MR. HAAG: Yes, I don't have the detailed numbers. I say that to just not to cause you to think that we did 23,000 hours of inspection. We didn't have that many --

MEMBER SCHULTZ: You didn't have that accurate --

MR. HAAG: Yes, yes.

MEMBER SCHULTZ: But that concept is consistent across the chart here?

MR. HAAG: Yes, it is. It is.

MEMBER SCHULTZ: It is not that suddenly you're thinking, gee, I need to add the office support as well and --

MR. HAAG: Yes, we have done that.

MEMBER SCHULTZ: It has already been incorporated?

MR. HAAG: All those years in total hours factor in both parts, whether it is the support, and it is my organization in the Region who deals with the managing of the program, our preparation for the inspection, the actual performance of the inspection, the travel time. So, it is all captured in there.

MEMBER SCHULTZ: It is all very important. So, I am glad it is included.

Thank you.

MR. HAAG: Yes. Okay.

So, the status of where we are at -- Justin, will you go back to the other slide? -- where we are currently at right now is that we have approximately 100 open items for IP&S. That means we have closed out over 450 of the items.

A little clarification there. For those 100 items that remain open, for pretty much all of them, we have done some level of inspection. While they're still open and we need to do some additional inspection, our goal was to inspect these things once they became available.

And what we didn't want to do is wait until the end and, then, go off and inspect an area. Because, typically, these inspections are two-part. So, we will take a look at the proposed corrective action. And many of these things are actions to resolve a problem. Whether it is a problem dealing with a bulletin, a Generic Letter, a TMI action item, there is typically a corrective action or activities, TVA planning to do. So, we look at what are those efforts. Do they seem appropriate to address the issue?

And then, the second part would go out there and actually do some sampling, whether it is actually watching the work being performed in place or looking after the work has been done, verifying it is complete.

So, I take a little bit of time to talk about. So, for many of the remaining 100 items, the majority of them we have actually looked at TVA's planned corrective actions, and we are satisfied. So now, we are waiting on actually work in place or some level of verification, so we can close out the item.

So, our focus now, because it is getting down to less than a year to complete these remaining items, so we have tried, for all of these items we have tried to tie to what TVA needs to do, needs to accomplish, for us to be able to perform the inspection. We have asked for a date from TVA; when is that going to be done? And then, we have scheduled our inspection to coincide either with that activity or following it, so we can do some level of verification.

And that allows us to maintain the flexibility. As their schedule for a particular item changes, we can also, then, correspondingly, make a change in our inspection schedule.

So, I will give you an example, two examples of the remaining 100 items, just to kind of give you an understanding of what is left to be done. Ten of them are involving some level of inspection or verification that need to be performed either during or after the hot functional testing.

An example would be Bulletin 88-12 dealing with the pressurizer surge line thermostratification. So, the remaining inspection we have to do is actually during the hot functional testing. We are going to go out there and actually look at the pipe movement to make sure it meets what TVA has predicted as far as movement and satisfies it.

So, we have already looked at the corrective actions, their analysis, where they had issues. And now, we need to go out and actually observe pipe movement; again, make sure it meets their predictive values.

Another area that we have got a fairly-large population is the fire protection items. There's 10 IP&S items that remain open for fire protection. So, for fire protection, we have done a significant amount of work already. We have looked at some of the historical open items. We have closed some of those. We have looked at their manual operator actions, how they went out and did the walkdowns and the timing verification. And we have also spent three weeks looking at more of the traditional fire protection areas.

So, we have completed that, but we still have 10 items that we need to inspect, and most of those are tied to field verification. For example, they need to go out and do some modifications, installation of the reactor coolant pump, oil collection, drainpiping, and the shield sprays. So, they haven't done those yet. We've got timeframes on when that work is planned to be done. We will go out and inspect it once it is complete.

So, the only other point I wanted to make here on the hours. So, this is historically what we have done. Looking forward, for all the areas that we need to inspect -- those would be the IP&S items, closing out the remaining 100 items, performing the remaining preop testing inspections and the operational preparedness inspections -- we have scoped those out and we have got an estimate as far as how much time it is going to take. And we believe, we have a high level of confidence that the Region either has sufficient inspection resources or we have the ability to use inspectors from the other regions to supplement our effort to be able to complete the inspections.

MEMBER BLEY: This brings us up-to-date. What are you predicting for the coming year?

MR. HAAG: That's what I'm saying. So, we have looked at the remaining inspections we have left to do for the 100 IP&S items for the remaining preop testing and the other areas. Based on that amount of work, we believe we have high level of confidence we have got sufficient --

MEMBER BLEY: Is it more or less than 2014? It is quite a bit less? Is that right, or no?

MR. HAAG: When you factor in some of the startup testing, it will probably be at least as much.

MEMBER BLEY: At least as much?

MR. HAAG: Yes. And we have got some of the other major inspections that I haven't talked about that have yet to be performed that will be included in it. So, you will see that on our last slide where it talks about remaining inspections. Again, some of the things that we haven't done in the past need to be performed.

MEMBER BROWN: Just before you leave that, I guess a point of calibration.

MR. HAAG: Yes.

MEMBER BROWN: Twenty-three thousand hours? You all inspect 265 days a year? I just divided it by that and came out with 63 hours a day.

MR. HAAG: Yes.

MEMBER BROWN: That is a fairly hefty amount. That is eight people if it is just eight hours in a day. I just wondered, you said you had enough resources. And that is a spike relative to 2013. So, whether you all have incoming staffing, borrowed it, or whatever?

MR. HAAG: So, the staffing we have directly devoted to the Watts Bar Unit 2 is pretty much under my Branch. We have got four resident inspectors. They are there full-time. They don't typically go out on the weekends, but they are at least 40 hours a week. And most of their time is devoted towards the project. There is some other work, you know, training and things like that which doesn't get included in those hours.

And then, in the Region there are four inspectors who work directly for me. And the vast majority of their time is also dedicated to the project.

MEMBER BROWN: So, that is about eight people per day then?

MR. HAAG: And then, we have got the inspectors from our Division of Construction

Inspection, the specialists who look at welding, electrical, civil. So, we have got those individuals.

We have got the folks in the Division of Reactor Safety to look at fire protection, to look at the emergency preparedness, the health physics.

So, we draw on a large group of the regional inspectors.

MEMBER BROWN: Okay. I'm just remembering some previous discussions several years ago when you were here.

MR. HAAG: Yes.

MEMBER BROWN: And I didn't remember, but the numbers just seemed bigger than what I remembered. And that is why I was asking the question if you all are getting suitable support all the way across the board. I mean, that is a lot of people.

MR. HAAG: Yes, it is.

MEMBER RICCARDELLA: It is 11 man-years.

MR. HAAG: Yes, yes.

MEMBER BROWN: I was generous. If I compress it down to 250 days, then you're right, it bounces up by another three people or so. So, anyway, that was just trying to get a calibration; that's all.

Thank you.

MR. HAAG: Yes, it is a significant

effort. And again, for 2015, will it be the exact same amount? You know, I don't have those numbers right now.

And when I say we estimated, it was an estimate. One of the things we have learned is estimates are difficult to necessarily come up at the beginning. It is almost, you know, as you work through them, some of the items are spot-on, but other items that we didn't anticipate problems or where the scope of the inspection changes those estimates.

So, on to the preoperational testing inspections. So, Manual Chapter 2513 specifies the inspections that need to be associated for preop testing. And it includes mandatory tests. These are some of the larger, more complex tests such as hot functional, the RCS hydro, loss of offsite power.

And then, the other area are the primal system tests. Those are the actual testing of safety-related systems and allowances that you can pick and choose different systems to go ahead and actually observe. Those are the primal tests. And I will talk about those as far as what we have done there later.

So, we have a team leader, one of the four people directly devoted towards Watt Bar Project. His sole responsibility or primary function is dealing with preop testing.

MEMBER BROWN: Just another thing of interest. You sampled it? I mean, you can't, obviously, observe all the testing.

MR. HAAG: That's right.

MEMBER BROWN: That's impossible.

Is there a requirement that any non-compliant results get reported to you all for followup or do they just take care of them and, then, eventually report? Something doesn't work, doesn't meet the spec, or whatever the test requirement is? I'm just wondering how those get handled, if they are silent, or do you actually hear about, well, they were running a test last night and it didn't meet the requirements?

MR. HAAG: Well, I will give you two parts to that answer. As far as our program inspection, we have got certain tests that we need to witness and follow up and look at the data results. So, those are the tests we focus on.

There is another subset of tests that we have to do a less-intensive effort. So, we might catch test deficiency notice that way.

And then, we've got the resident inspectors and the regional folks who attend the routine TVA meetings. So, they have a morning meeting dealing with the construction project. They also have another meeting dealing with testing. And we typically attend both of those meetings. So, if a problem would come up, we would normally hear about it that way, you know, just through normal communications.

MEMBER BROWN: But there is no formal report? There is no formal reporting?

MR. HAAG: I am not aware of a formal --

MEMBER BROWN: Okay.

MR. HAAG: -- unless it rises to a construction deficiency report that would be part of our regulations. They would have to notify us.

MEMBER BLEY: But, otherwise, that affects whatever is ongoing, have them retest, and --

MR. HAAG: Yes.

MEMBER BLEY: And eventually, the final report says everything is good?

MR. HAAG: And then, we sample a good number of the testing, actually, either observing or looking at the test results, and we would look at something there.

MEMBER BROWN: It's interesting. Every time one of my things didn't pass, I heard about it at two o'clock in the morning. It didn't make any difference for one rakeover.

MR. HAAG: Yes, yes.

So, I mentioned the team leader. Again, he is devoted to the preop testing program. While he performs actually some of the actual testing inspections, he is also a primary interface in coordinating with TVA on the testing schedule and making sure we have people available and any changes to their schedule we're aware of, and that we can accommodate.

So, as far as the status of our inspections, we have completed one of the six mandatory test inspections. And that was for the RCS hydro. We are waiting on TVA to perform the remaining five mandatory tests, and we will observe those as they occur.

We selected 10 systems to contain or to satisfy the primal systems. We have those mapped out. We have got lead inspectors assigned to all those 10 systems and we are observing those as they come through. Currently, we have witnessed portions of six of the 10 systems. And again, we have got plans to witness the remaining portions of the 10 systems.

So, our biggest challenge to date has really been the frequently-schedule for testing. And that's not unexpected. Things happen, and we have to be responsive to that.

We are fortunate in that we have four resident inspectors, and we have been using them to some degree to supplement, you know, either a quick change or something that falls over into the weekend; we need them.

So, the frequently-changing test schedule really has affected mostly the regional inspectors having to alter their schedule, if they are assigned to a particular test. And we have been fortunate, again, that we have had the four resident inspectors, and all four of those individuals have had the training and they are capable of doing some preop testing inspections.

CHAIRMAN RAY: Bob, I appreciate the review of the testing, as you have described it, but there is the question that at least some of us have thought to be as important at least. And that is the effect of the Unit 2 testing on Unit 1. I don't think you have mentioned how you look at that implication. I mean, do you try to independently evaluate it or do you make sure that TVA has considered it? How is it done?

MR. HAAG: Yes. So, that was actually the next point I was trying to make.

CHAIRMAN RAY: Oh, my goodness.

(Laughter.)

MR. HAAG: Yes.

CHAIRMAN RAY: Excuse me.

MR. HAAG: Yes. It was a very good lead-in.

CHAIRMAN RAY: All right.

MR. HAAG: So, during our preop testing, we have actually increased our level of review in this area as far as Unit 2 activities, whether it is a construction activity or whether it is a testing activity, to ensure they are not adversely affecting Unit 1.

And as we pointed out earlier, the shared systems, that is where we have spent of our additional review effort in looking at, again, TVA's controls they have in place for the testing, management controls they have for some of the construction activities.

The shared systems were specifically ERCW. That is the Service Water System and the Component Cooling System. I called that component cooling water.

So, those were two of the primal tests that we selected for review. As part of all primal tests, we have to review the test procedure upfront, make sure we are satisfied that they are actually meeting the FSAR commitments, numbers. They have acceptance criteria in there.

For these shared systems, we will look at their controls to ensure the Unit 1 portion of the system maintains its capability to perform a safety function. For example, TVA had an elaborate system to do flushing for the Component Cooling System. They brought strainers into the ops building, thousands of feet of temporary piping. We looked at that in great level of detail. We challenged them on some of the seismic considerations for this new piping and equipment.

And so, that is an example of where we have looked at their controls they have put in place to ensure Unit 2 activities, whether it is construction activity or whether it is testing activity, again, it is not adversely affecting Unit 1.

And then, the other point there is at the beginning of the project we instituted some additional requirements for the Region and we issued a Regional Office notice that dealt with Unit 2, Unit 1/Unit 2 construction interface controls.

And what that does, because the inspection program really was silent on that, we instituted for both the Unit 1 resident inspector staff and the Unit 2 resident inspector staff sample requirements where they would have to go out and observe some of the controls TVA has put in place, whether they have interface meetings, whether we independently sample some of the work activities to make sure they have recognized and considered vulnerable points and have controls for those vulnerable points. And we have been doing those inspections since 2010.

So, does that answer your question as far as looking at potential impacts on Unit 1?

CHAIRMAN RAY: Yes. Just made sure that it is at least as important as the testing of Unit 2 itself.

MR. HAAG: Yes.

And then, I guess the last point there is we are very cognizant of when there is a problem; there is an interface problem where a Unit 2 construction worker goes over and inadvertently operates or changes a Unit 1 component. So, we follow up on the corrective actions. We look for trends there. So, we do maintain a high level of awareness when problems do occur, that TVA has looked at them and they have addressed them.

MEMBER SKILLMAN: Bob, have you issued any

NOVs as a consequence of --

MR. HAAG: Yes, yes.

MEMBER SKILLMAN: Approximately how many and how severe?

MR. HAAG: They have all been at severity Level 4. How many? I know of at least two examples, and these were self-revealing instances where, again, they went to the wrong unit affected, you know, whether it was lifting the leaves and, then, the control room operator saw something happening in the control room, self-revealing. So, those were at least I know of two examples where we followed up and there was a failure to follow procedure dealing with the actual work and going on the wrong unit.

MEMBER SKILLMAN: Okay. Thank you.

MR. HAAG: Yes.

So, the operational preparedness inspections, Manual Chapter 2513, Appendix B, talks about the operational preparedness inspections. And I will go into just a little bit of detail.

So, those are the inspections that we look at as far as management controls and procedures that are necessary for operating the reactor to perform or to operate. So, we look at the areas of operations, radiological controls, chemistry, maintenance, surveillance, QA.

Out of those inspections -- again, they are specified in Appendix B of the Manual Chapter -- we have completed 18 of the 36 inspection procedures. So, we have done about half of the inspection procedures spelled out for the program.

We are currently on track to either have those completed or we are waiting on TVA to give us an acknowledgment that what we are looking for will be ready. And that should be done the spring of this year.

Most of those inspections, again, are done by the Division of Reactor Safety in the Region. So, we have frequent contact with them to make sure they are aware of changes that are occurring and they can support that.

So, out of those 18, the last bullet there talks about the areas where we have pretty much completed the inspections. And those are in operations, health physics, and quality assurance.

The fire protection inspection, there is a specific inspection procedure that deals with some of the more programmatic fire protection areas, and the recent three-week inspection we completed back in December, completed the majority of those inspections.

So, the areas that are remaining, I have talked several times about the IP&S items. We have those 100 inspections that we need to do. I gave you the status on the preoperational testing inspections and the operational preparedness. Obviously, we have got to complete those inspections.

A new one that I had mentioned earlier is the operational readiness assessment team. That is almost an independent look outside of the effort that is in place right now to look at TVA's readiness to operate the second unit.

We have plans that we are working on as far as pulling that team together. And that team will perform that inspection this spring. That will give us really a second set of eyes on many of the areas that we have already looked at.

There's the followup to the Fukushima Orders, Temporary Instruction 191. It is focusing mainly on mitigating strategies TVA has put in place following the Order. That inspection most likely will take place in March of this year. There are just a few things that need to be complete and the Safety Evaluation needs to be issued before we can complete that inspection.

Fire protection is another area. I have talked about what we have already done. There are some followup areas from the programmatic inspection where we are looking at resolution of some of the items that we have identified during the inspection. So, we will have to go back and follow up on those and the remaining open items.

And the cybersecurity inspection, we have already completed a two-week initial review of cybersecurity controls, and we need to go back and follow up on that inspection. There are some remaining items that we have yet to do.

CHAIRMAN RAY: Now is it still the case that Unit 1's implementation is lagging behind Unit 2?

MR. HAAG: As far as --

CHAIRMAN RAY: I seem to recall there was an issue with regard to cybersecurity, that Unit 2 would implement ahead of EOL, but Unit 1 was going to lag further behind.

MR. HAAG: Yes, there was a difference in TVA's implementation strategy and the milestones for Unit 1 and Unit 2. There has been some recent dialog, and TVA has plans to change that. I am not sure if they will be exactly consistent. But our inspection, that is one of the things that our inspection needs to wait on, is that if TVA's changing their commitments for cybersecurity, we need to understand what they are, so we can figure out what we need to inspect on Unit 2 before a licensing decision.

CHAIRMAN RAY: So, it is not 100-percent resolved, but there is some dialog still going on?

MR. HAAG: Yes, I think I would characterize it like that.

MR. POOLE: Yes, that is a good way to put it. I guess, actually, recently, as of last week, we gave someone their new implementation schedule for Unit 2.

Essentially, you're correct, Unit 1 for Milestone 8 has an implementation date in 2017, I want to say. And then, Gordon is going to correct me. And then, they have recently submitted something similar with the Unit 2, Milestone 8.

CHAIRMAN RAY: Yes, before he answers, I want to make clear, we are not here to review Unit 1. It is just that implementation of Unit 1 after Unit 2, I don't know what that implications that has for Unit 2.

Anyway, go ahead.

MR. ARENT: So, what we have done is -- this is Gordon Arent, Licensing for Watts Bar -- what we have done is we have actually realigned that, such that Unit 1 will be the lead unit. They will complete Milestone 8 about six to nine months prior to Unit 2 completing Milestone 8.

CHAIRMAN RAY: I see.

MR. HAAG: So, that was all of my prepared remarks as far as our inspections. Any additional questions?

CHAIRMAN RAY: Anybody?

(No response.)

All right, Bob, well done. Thank you.

MR. HAAG: Thank you.

CHAIRMAN RAY: And if there is nothing more at the moment, we will recess almost on schedule and have lunch, reconvening at one o'clock.

(Whereupon, the foregoing matter went off the record for lunch at 12:06 p.m. and went back on the record at 1:00 p.m.)

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

1:00 p.m.

CHAIRMAN RAY: Okay, we're back on the record.

Justin, I believe you will begin.

MR. POOLE: That's correct.

For the next two slides, I just wanted to go over, at least at a high level, some of the repeat from previous meetings about the status of licensing activities for Watts Bar Unit 2.

So, when Watts Bar Unit 1 received its operating license in 1996, the staff had reviewed up to FSAR Amendment 91. In updating its license application for Unit 2, TVA maintained that the numeric system and the first submittal was Amendment 92. To date, we have received up to Amendment 112.

In reviewing all those amendments, the staff has documents its review and the supplements to this original Safety Evaluation Report. In order to license Unit 1, there was 20 supplements to the original Safety Evaluation Report. Again, keeping with that same consistency for Unit 2, we started with 21, which identified the framework for our review. And then, 22 through 27, as you can see on the slide above, again, at a high level, documents which chapters were reviewed as part of the review for Unit 2.

For 27, it mainly consisted of closing out of open items, as essentially the major sections of the FSAR had already been reviewed. And this continue for SSER 28, which we expect to issue in the spring timeframe, and then, there will be an SSER 29, which will go along with the operating license.

So, the last bullet there kind of reiterates what I somewhat just said, in that the staff has completed its initial review of the FSAR, and the remaining areas to review are essentially changes being made to address some of the open items that the staff identified or on certain occasions, although not many, just updates that TVA has made since the staff had previously reviewed a section.

Next slide.

So, during the course of the review the staff had identified 128 open items and documented and tracked these and Appendix HH of the SSER. With the issuance of SSER 27, a total of 106 of these have been closed. Of the 22 items that remain, they can essentially be broken down into two different categories: items requiring confirmation, things like updating the FSAR, followup via an inspection -- and those are some examples. I'm sorry.

Or the other category are those requiring evaluation.

As you can see in the lower two bullets, of the 22 items, 16 fall into the category of confirmation while six remain in the category of requiring additional evaluation by the staff. Of these six, one is related to hydrology, which we will be talking about today.

And although the LAR -- sorry -- the License Amendment for Unit 1 is almost completed, and we hope to issue that relatively shortly here, it was not done in time to put in SSER 27. So, that is why that open item still remains. But, regardless of that, the work is completed and we will document the findings that we publish in the Unit 1 LAR and in SSER 28.

An additional two of these six deal with EQ verification. And those are going to be done as part of the inspection program.

There is another open item related to ensuring the indemnity agreement is submitted and completed. That is one of the final steps issuing the operating license.

Yet another one relates to ensuring the test results for radio interference on a specific piece of a component come out satisfactorily. So, again, essentially, it is almost an inspection item.

So, if you do all that math, it essentially comes down to one open item that the staff is still actively engaging with TVA to resolve.

MEMBER SKILLMAN: Justin, on two occasions you reinforced Unit 1. Is that what you meant to say? Or did you mean to say Unit 2?

MR. POOLE: I think that was when I was referring to the LAR for Unit -- for hydrology, which, as mentioned earlier when TVA was up here, they are done simultaneously. They are the flooding hazards at Unit 1 are the same for Unit 2.

MEMBER SKILLMAN: Okay. All right.

MR. POOLE: So, as we will talk about, essentially, there were two identified and correction needed to be made to their licensing basis for Unit 1. So, they submitted the LAR for Unit 1 and the identical information was submitted on the Unit 2 FSAR.

MEMBER SKILLMAN: Okay. I was just making sure I was hearing accurately --

MR. POOLE: Yes.

MEMBER SKILLMAN: -- and understanding the context.

Thank you.

MR. POOLE: Yes.

MEMBER SKILLMAN: Thanks.

MR. POOLE: With that, next slide, and if there are no questions, we will move on to hydrology.

MR. LUPOLD: Okay. I'm --

MR. POOLE: I'm sorry, Tim, I was just going to give you --

MR. LUPOLD: Oh, give me an intro then?

MR. POOLE: Yes.

MR. LUPOLD: All right.

MR. POOLE: Sorry about that.

So, in SSER 24, and as discussed in our earlier ACRS Subcommittee, the staff had previously documented the changes to Section 2.4.10, Flooding Protection, due to the changes in the problem maximum flood level.

Following that meeting, additional work had been done by both TVA and the staff related to the problem of the maximum flood level seen at the site during design basis events.

In order to correct the known deficiencies, as I was just saying, in its flow level calculation for the operating unit, TVA submitted a license amendment for Unit 1 in 2012 and, subsequently, submitted the same information a month later for Unit 2. The staff is nearing completion of its review, and a license amendment for Unit 1 is in final concurrence and should be issued shortly. As the operating unit in Unit 2 are co-located and share facilities and equipment, design basis flood for Unit 1 is the same as design basis flood for Unit 2.

As I mentioned earlier, the completion of the LAR did not line up with the publication of 27, but, instead, will be published in SSER 28 for Unit 2.

I will now turn it over to Mr. Lupold, the Branch Chief in NRR Mechanical Branch, to present what the staff did as far as their review for the Watts Bar site.

MR. LUPOLD: Thanks, Justin. I appreciate that.

I am Tim Lupold, the Mechanical Civil Engineering Branch in NRR in the Division of Engineering. I am the Branch Chief, but the real work was done by many people within the organization.

And I just want to mention that we had Region II working on this. Tony Ponko, Anthony Masters, they did a lot of work in assessing the dam stability.

We have Stephen Breithaupt, who is actually on the line today and available if questions come up. He is with the Pacific Northwest National Laboratory, and he is actually on detail right now with the Office of New Reactors.

And also in the audience we have Ken See from New Reactors, if questions come up that I can't answer, and part of my staff, Dan Hoang is here. He specializes in dam stability also. And my hydrologist is Yuan Cheng. He is here in the audience, too. These are the guys that really have the technical background on this.

All right. I am going to flip over and talk about Open Item 133, the sand basket stability. There are issues/questions about whether or not these would be stable in a seismic event. As you heard this morning, TVA got back to us and talked to us about this, and he said that these baskets are not credited in a seismic event.

We looked at that. We evaluated that. We said that looks acceptable for the seismic event. They are used only in calculating the probable maximum flood, and they are needed for that. And they do need to get replaced with the sturdy, permanent modification eventually, and that is why we have the license condition to do that.

There is the commitment out there to have the permanent modifications in place by May 31, 2015. As we heard this morning, we had the 1900 feet of HESCO barriers at the Fort Loudoun Dam, which won't be completed until February 1st.

And the real reason for that is the location of those right next to a road, and the actual modifications to replace those would require road closures, detours, impact emergency vehicles in the area.

In the overall perspective of safety, the best thing to do is to allow that bridge to get constructed down there, and then, they won't need to have these safety issues for the general population down in Tennessee.

So, the bottom line is we looked at this, we evaluated it, and we accepted the fact that the resolution of this item, we consider it closed at this point.

All right. Moving on to the hydrology review, the LAR submitted to update licensing basis for Watts Bar Nuclear Unit 1, the same basis as for Watts Bar Nuclear 2.

When we got the license amendment request in, we started looking at what are the differences in this licensing basis versus the existing licensing basis. And we noticed that the HEC-RAS -- HEC-RAS is the Hydrologic Engineering Center River Analysis

System -- that was used as opposed to the simulated open channel hydraulics model, which TVA had developed.

We also looked to see what was being used for dam stability criteria and whether the FERC guidelines were being used for that. And they did look at that. They did use the FERC guidelines for the dams.

And when I talk "dam," I'm talking about the concrete structure portion. There are other modifications that were done to wing walls or embankments, or things like that. And there are other standards that may apply to that, which may not be FERC standards.

All right. We also updated the probable maximum precipitation to produce the probable maximum flood elevation. And we noticed that industry standards that were used on that was the HMR-41 to calculate the maximum probable precipitation.

And I will go into this a little bit more, I think, in another slide. Yes, I will mention that in the next slide in a little bit more detail.

And the actual license amendment request reevaluated dam stability for the postulated dam failures under the PMF, meaning that they actually assumed certain dams will fail in their model that contribute to the problem in maximum flood condition.

Originally, there weren't dam failures that were assumed. All right.

And this licensing basis also credited the permanent flood protection barriers, like I had mentioned for the HESCO barriers, in the analysis. So, that was necessary in order to make sure that any overtopping of the dams occurred on the concrete structures and it wouldn't occur on the embankments and erode the embankments and cause failure to one side of the dam.

MEMBER SKILLMAN: Tim, let me ask the same question to you --

MR. LUPOLD: Sure.

MEMBER SKILLMAN: -- that I asked TVA a couple of hours ago in the draft hydrology document that we were asked to review.

There is the statement that identifies permutations and combinations of SSE, OBE, FSSE, BMF, 25-year. There are five sets of those combinations.

What in your review ensured that the most conservative WSE, Water Surface Elevation, was identified?

MR. LUPOLD: Well, we looked at it to see what volume of water was behind those dams that were assumed to fail and made sure that they would get the maximum flow coming down the river in order to achieve that.

MEMBER SKILLMAN: Did you use an independent model or independent calculation?

MR. LUPOLD: We have a model, HEC-RAS, for that. We have our own model. Actually, I mentioned Stephen Breithaupt from PNNL. He had established a HEC-RAS model to be able to do confirmatory analysis for these types of runs that TVA had done.

MEMBER SKILLMAN: So, should I interpret your answer to be, as a result of what he did, you are convinced that what TVA presented in terms of the maximum water surface elevation is accurate?

MR. LUPOLD: That's correct.

MEMBER SCHULTZ: Did that model use TVA's assumptions? In other words, was there interaction with TVA to determine the input parameters associated with the HEC-RAS model that PNNL did or did they develop, the regulatory developed a separate set, your own evaluation of input?

MR. LUPOLD: TVA provided to us the inputs that they used into their model when they sent us their latest submittal in -- what was that? -- September 2014. All right. So, we looked at that and looked at those models.

And we did some work on that to say that, yes, these are the appropriate inputs to use. For example, we go back and look and see if they used the right storm, the 7,980-square-mile storm vis the 21,400-square-mile storm. We made sure that things were calculated, the average precipitation over those areas were calculated appropriately, and used as inputs into the model. And we did various independent runs to make sure that we were coming up with numbers that were consistent with what it was that TVA had established. Okay?

MEMBER RICCARDELLA: Tim, in your judgment, with all this new work, are they well on their way to meeting the NTTF 2.1 requirements? Or does that require a whole new analysis?

MR. LUPOLD: You know, I really don't want to answer that question because I am not knowledgeable enough in that area at this moment to talk about the Near-Term Task Force or work in Fukushima 2.1.

And there are a lot of different assumptions that are going to have to be made for that versus this, but it is really a hard question for me to answer because I haven't looked into that at all up to this point. We have completely been concentrating on the current licensing basis. So, I apologize for that, but I just don't have an answer for you there.

MR. POOLE: I guess I would just add one thing that at least seems on the surface to be a benefit is that TVA went from their own SOCH code, their own developed code, to the HEC-RAS modeling, which is what licensees are using as part of the 2.1. So, there is at least some step in the right direction.

MR. LUPOLD: So, they will have that model already established. And it will be easier for us to look at what they submit when they use that model for the Near-Term Task Force. But, other than that, we really haven't looked at it at this point yet. At least I haven't and my Branch hasn't. We have been almost dedicated on the current licensing basis.

Okay. Yes. The results of the hydrology review are that they came up with the PMF of 738.9 feet, and this was the result of assuming the 7,980-square-mile storm is the one that achieves the maximum PMF at the site. We checked that. We compared it with a 21,400-square-mile storm. TVA did the same thing. They looked at them and said which one provides the maximum PMF, and that was the deciding factor on which storm to use in the model.

The two different storms have different centers. They are located, the centers are located in different places. So, that comes into play.

And we are convinced that they did a satisfactory job, an adequate job in calculating the PMF. Their assumptions were correct. The calibration of the model that they did was appropriate. They used the storm, the 1973 storm, the 2003 storm, in order to do the calibration and come up with the factors for the channels. Our confirmatory numbers compared favorably with theirs.

And so, that is what the PMF calculated, is the 738.9. Now, as we heard this morning, TVA still used the 739.2 as their PMF, call it their licensing basis PMF because that is what it was at one time. All the procedures were written for that. And so, they maintained at that point. That gives them a little bit of margin, should something happen in the future. If we find a penetration out there at 739 that is not quite sealed, hey, you can take credit for that kind of thing. That is the still water level.

And then, in addition to that, you would want to know what is the wave runup. All right. So, they calculated the wave runup for the different locations onsite and added those values to the still water location. And they got those for the buildings, and that is what they used to determine what the height was that they had to protect their equipment to inside their buildings, should there be any leaks into the buildings. And in cases water does get into the buildings, they made the modifications to the equipment that is needed to pull the plant down in order to protect the plant and to preserve safety.

Okay. I have already really talked a lot about some of the items that are on this slide. We reviewed/performed confirmatory analysis, as I mentioned. We looked at the watershed hydrology and the river hydraulic simulations. We made sure that the PMP controlling storm was the 7,980-square-mile storm. And we looked at the inputs, the assumptions set up and resulting data.

The stability analysis of the critical dams, that was something we looked at. We actually conducted an audit to look at the dam stability analysis that was done, and we made sure that there was adequate safety factors, that they assumed the dam was going to remain intact. And we made sure that the modifications were being done and would restore the safety factors for other dams that they credited into the analysis, such as the Fort Loudoun Dam and Tellico, Douglas, you know, those dams that are being modified.

Okay. And so, when we looked at

everything, we believe that they had addressed the issues that we had identified in earlier versions of the hydraulic analysis. And we have no other questions or issues associated with the analysis. And the only thing we did is we made license conditions of those modifications that have to be completed that support the analysis.

CHAIRMAN RAY: Is there anything here that you would have not done if Unit 2 wasn't seeking an operating license? In other words, isn't all of this stuff that was having to be done for Unit 1? Or is there something that we have missed that is only there because of Unit 2?

MR. POOLE: No, I think you're right. This all stemmed, as I think TVA mentioned in their presentation earlier, from an inspection that was done at Bellefonte for the new reactor plants, 3 and 4. There is errors identified in their use of the SOCH code that trickled down to TVA reevaluating the river system, which caused them to identify an error that they used in one of their coefficients which ended up causing the flood level to be higher at the new site.

So, like I was trying to say before, yes, for Unit 1, they needed to do this anyway. They needed to correct what was essentially a deficient licensing basis for the operating plant.

CHAIRMAN RAY: The Draft Safety Evaluation I looked at never mentioned Unit 2. It's all about Unit 1.

MR. POOLE: Because that is the --

CHAIRMAN RAY: Right. And so, my point I guess would be that, as much as this has been a part of the discussion today, it still is a discussion that would have taken place in the agency relative to Unit 1 if Unit 2 was never on the table.

MR. POOLE: Right. That's correct. Yes.

MR. LUPOLD: I'm not aware of anything on Unit 2 that would change anything that we have done up to this point.

CHAIRMAN RAY: Yes.

MR. POOLE: But, since we had come before you before in 2011 on the section for Unit 2, we wanted to --

CHAIRMAN RAY: Well, my point is that, to some degree, we might feel that this is a consequence of the Unit 2 operating license action, and I don't think it is.

MR. LUPOLD: Correct.

CHAIRMAN RAY: Because we can argue a lot about -- you know, PMF, standing for Probable Maximum, it's a non sequitur to begin with. And we are used to looking at things truly that are probabilistic, and this isn't at all.

MR. LUPOLD: Yes.

CHAIRMAN RAY: And so, there is a lot of room here for commentary about the difference between this analysis and what we are more used to in the world of seismology, for example.

I really this is tied-in so much to the Corps of Engineers and other things outside the agency. But is there anything underway to move hydrology into a realm more like seismology has been for quite some time with a probabilistic hazard curve and all that kind of stuff?

MR. LUPOLD: We have nothing at this time that we are working on in order to do that.

CHAIRMAN RAY: So, all right. That answers my question. But it is a big disconnect between the way we look at seismic events, for example, and the way we look at seismic events in the context of hydrology. They are just like night and day.

MR. POOLE: Ken See from NRO, he may have more insight on that.

CHAIRMAN RAY: Sure.

MR. SEE: Yes, my name is Ken -- is this on (referring to microphone)?

MR. POOLE: Yes.

MR. SEE: My name is Ken See with the Office of New Reactors.

There is a move afoot to move this into probabilistic approaches. There is a probabilistic flood hazard analysis research plan that is either been concurred on or very near concurrence. So, we are moving in a direction that I would say mimics the seismic approach.

So, we have heard the criticisms and the concerns, and we are responding.

CHAIRMAN RAY: Oh, good. Well, I am glad you came and told us that. Otherwise, somebody might feel a need to remind you about that.

(Laughter.)

But, in the absence of that, since it is underway, why, we will accept that as a fact.

Thank you.

Okay. Anything else?

(No response.)

All right.

MR. LUPOLD: Okay. Thank you.

CHAIRMAN RAY: We can move on from

hydrology. Thank you.

MR. POOLE: Now we move to fire protection.

Okay. So, TVA mentioned earlier, there was an item identified by the ACRS in their November 2013 letter to come back to the Committee and go over how we deal with operator manual actions.

So, I have Dan Frumkin and Charlie Moulton here from the Fire Protection Branch to go through that.

MR. FRUMKIN: So, I am Dan Frumkin. I'm a Senior Fire Protection Engineer in NRR.

And I am going to go through some timelines that I think come to answer the question about time margin and reliability.

Just a refresher. The letter from 2012 or 2013 asked the staff to explain the feasibility of all the operator manual actions take in response to a fire as evaluated in accordance to Reg Guide 1.189 and want to understand how the timeline and methods outlined in NUREG-1852, which is called "Demonstrating Feasibility and Reliability of Operator Manual Actions Related to Fire," are used to evaluate times for fire detection. And if you notice on my image here, the fire detection happens around time zero. Condition diagnosis, personnel assembly, communications and coordination, supervisory directions, those all start as the event begins to propagate through. Transit, implementation of the required times, required actions, and then, moves on to including an assessment of associated uncertainties and available time margins. So, this figure shows where those concepts come into the context of the NUREG-1852 timeline.

This morning TVA presented slides that provide the status of these topics. And rather than repeat them, I am going to focus my remarks on how the staff has made the determination that these manual actions are reliable.

So, this morning's presentation was essentially feasible. Can they be done? When an operator or at TVA an auxiliary unit operator goes out, do they have the time, the resources? Are they impacted environmentally? And they can finish it in a certain amount of time. That's feasibility.

Reliability is defined as it is feasible and dependably repeatable. So, we just go to the next slide.

What came up during this morning's presentation a little bit is TVA has deviated from the NUREG-1852 timelines to some extent. And I will tell you -- and that was to simplify their entry point of starting to calculate the time.

Rather than estimating when the fire alarm would be received and comparing it to when damage may be expected to occur, TVA shifted the time zero to plant trip. What happens in zone B -- and I added these zones just to facilitate our conversation -- is there is a dynamic in the diagnosis and recall time. Because of the sensitivity of the detection that is really throughout the Watts Bar plant, we would expect the fire to be indicated before damage were to occur.

So, assuming that plant damage were to occur, zone B begins, and the damage may not have occurred yet, but there is also diagnosis going on by the plant operations as to whether this is an Appendix R fire that requires an Appendix R response.

MEMBER BLEY: When you say "damage," you are referring to losing safety equipment?

MR. FRUMKIN: So, when I say "damage," what is happening in the fire scenario is there's some what I call a source, a cabinet or transient or something. If the cabinet is damaged, it is really within the emergency operating procedures. Where fire comes into play and really was clear at Brown's Ferry is where that fire causes damage to a target that is outside of that source.

So, immediately when the fire starts, there is some sort of source damage.

MEMBER BLEY: Of course.

MR. FRUMKIN: But the plant emergency procedures should be, without even going to fire protection, should be very well equipped to respond to those, except for maybe some spurious actuations, but they should also generally be able to respond to those.

What we really are concerned about is where you have multiple train damage or multiple safety system damage.

MEMBER BLEY: Well, you're a fire guy, not a systems guy?

MR. FRUMKIN: Yes.

MEMBER BLEY: From an operator point of view, spurious actuations, yes, if you knew they were spurious, they are easy to deal with. If you don't know they're spurious and you don't know there's a fire, it could be very confusing.

But go ahead.

MR. FRUMKIN: Okay. So, that is what is going on in zone B. And what TVA has done, or at least at Watts Bar they have done, is they have taken that kind of uncertainty out of this equation and said that they are going to get a fire alarm; they are going to recall the operators. There is this diagnosis and direction that is going on. And then, upon a reactor trip is when their timeline starts.

So, if no plant trip occurs, the plant is considered stable and they wouldn't enter the fire response procedures. If there is no fire identified, but they do get a plant trip, again, they wouldn't enter the fire response procedures. And if the magnitude of the fire is judged not to be -- there is a fire, but the magnitude of the fire is not judged to have the potential effects on the structure, systems, and components important to necessary -- I wrote the wrong words -- but components necessary to achieve safe shutdown, the plant would rely on their normal shutdown procedures.

So, even if there is a fire alarm and a plant trip, it is going to be a judgment call on the part of the operations staff whether to enter the fire response procedures. The fire response procedures are often limiting and they send the operators down a certain path which may reduce the amount of equipment that they have to rely on. So, the operators are going to make a call whether to head down that path or continue to use their emergency operating procedures. And that is based on the available equipment and how they judge the extent of the damage.

MEMBER BROWN: They talked about calling the operators in three, five, and eight minutes, the last operator, an AUO --

MR. FRUMKIN: Yes.

MEMBER BROWN: -- or whatever it was.

Where does that fit in here? I mean, I am trying to get my head around the damage thing. I mean, if a cabinet catches fire and there is smoke, something is damaged. It may or may not trip the plant at that time, but somebody can put it out with a fire extinguisher appropriately squirted; the fire goes out.

How does that fit into your --

MR. FRUMKIN: So, the way that the recall occurs -- and this was talked about this morning -- is that the smoke detectors in the vast majority of these areas are, I guess you could use the word "fragile". You know, they are very sensitive to smoke, and they would go off very early. Whereas, the fire protection or the equipment to be damaged, whether it is a cable or some other component within the plant, they are fairly robust compared to smoke detectors. Smoke detectors are designed to go off quickly.

And because of the cross-zone nature of

most of these systems at Watts Bar, upon two smoke detectors actuating, which is really expected to occur before my target is damaged -- assuming my source is already damaged, but, for the most part, we expect that the plant can respond to that. Before the target is damaged, we should have a fire alarm, and that is when the AUOs are going to be recalled to the control room or wherever it is that they are going to be dispatched from.

So, they are not recalled at three, five, and eight minutes. They are recalled as soon as they get a cross-zone smoke alarm, and they are going to recall all eight of the AUOs and they are going to be staged at the control room awaiting the judgment of the plant manager or the shift supervisor and that plant trip. And that is when the time zero begins.

MEMBER BROWN: No, I understood they would all be called.

MR. FRUMKIN: Okay.

MEMBER BROWN: It was just a matter of how fast each, the farthest and the intermediate and the other. I am just trying to relate it to something actually happening; that's all.

If there is somebody in the area that squirts it with a fire extinguisher, is that allowed or do they have to wait for the fire brigade to get there?

MR. FRUMKIN: Right. And again -- well, not "again" -- but the fire brigade and the aux operators are separate. And so, the plant -- I mean, I guess the TVA staff can talk about what are the expectations of a staff member or plant staff member coming across a fire in the plant.

MR. BOTTORFF: Yes, sir. It's Michael Bottorff again.

MEMBER BROWN: Yes.

MR. BOTTORFF: If something is seen abnormal in the plant, all operators, maintenance, everybody that reports to Watts Bar that is given access has to go to general plant training. And in that generic training is, if I see smoke, fire, something falling, anything abnormal, the first response is to report to the main control room before an action is taken. We are not waiting on the fire brigade team, but the very first action is to report it to the main control --

MEMBER BROWN: No, I understand that. But, if he is there, if he sees a cabinet with smoke and, then, sparks or whatever -- and I presume there's fire extinguishers when I have --

MR. BOTTORFF: Yes, sir. And all of our operators are also trained to take action and their equipment.

MEMBER BROWN: So, they can put it out?

MR. BOTTORFF: Yes, sir.

MEMBER BROWN: Yes, okay. All right. That was just the point. I just wanted to understand a little bit of the mechanics; that's all.

MR. BOTTORFF: Yes, sir.

MEMBER BROWN: Thank you.

MEMBER BLEY: Now, just to make sure I don't get confused on language, you have zones up here to talk about time zones.

MR. FRUMKIN: Yes.

MEMBER BLEY: When you say "across-zone" fire alarms or smoke alarms, you are talking across Appendix R zones, right?

MR. FRUMKIN: No.

MEMBER BLEY: What are you talking about?

MR. FRUMKIN: Right. Okay. The majority of the systems at Watts Bar are what are described as cross-zone, free-action sprinkler systems. So, they have, to typically open the pre-action valve, you need two smoke detectors which are kind of in crossing grid patterns throughout the compartment.

MEMBER BLEY: So, those are sprinkler zones? It is another zone?

MR. FRUMKIN: It is zones of smoke detection.

MEMBER BLEY: Okay.

MR. FRUMKIN: So, you need both A train and B train of the smoke detection systems to actuate, but it is going to be A/B, A/B across. And like I say, smoke detectors are very sensitive. So, this is a way that TVA and a lot of plants that use these, the pre-action sprinkler systems, avoid equipment damage, like someone with scaffolding knocking off a sprinkler head; there's no fire, and then, spilling water everywhere.

MEMBER BLEY: So, I guess I hadn't realized this. I wasn't around for the other meetings. I didn't come to the meetings.

If cross-zone alarms go off, the sprinklers actuate, if there are sprinklers in this area?

MR. FRUMKIN: No. The sprinklers, like in this room, have fusible links. So, you would need two smoke detectors of opposite zones to go off. That would actuate the pre-action valve. It would open, but --

MEMBER BLEY: Charging the --

MR. FRUMKIN: Charging the line.

MEMBER BLEY: Charging the fire equipment?

MR. FRUMKIN: Right.

MEMBER BLEY: Okay. And alarming and the control -- well, if only one goes off, you still get an alarm in the control room?

MR. FRUMKIN: Correct.

MEMBER BLEY: Or somewhere?

MR. FRUMKIN: So, there is a distinction there. If one goes off, there would be an alarm in the control room. The control room would not at that point activate the fire response procedures, but they would send staff to go investigate.

MEMBER BLEY: Okay.

MR. FRUMKIN: But, upon that second one, they would --

MEMBER BLEY: You said something earlier that kind of I didn't quite follow. You said, if there is a fire but not a reactor trip, you won't activate, they won't activate the fire procedure?

MR. FRUMKIN: So, they're --

MEMBER BLEY: If they've got a fire in the safety equipment area and you're wiping out some of your standby safety equipment, they don't actuate the fire procedure?

MR. FRUMKIN: Well, there's two fire procedures. There's one in response to the fire. I think that is 30.1. And then, there is the area-specific safe shutdown procedures. And the area-specific safe shutdown procedures are the ones where the plant will start stepping through actions, but --

MEMBER BLEY: But before you turn it over to him --

MR. FRUMKIN: Yes, okay.

MEMBER BLEY: -- I am going to expand the question a little bit.

You also said, if there's a fire and a trip and you go into those fire response procedures, you stop the EOPs, is that true?

MR. BOTTORFF: To clear up a little bit of confusion, first of all, if there is a fire reported and we have verified that we have a fire, we have a separate abnormal operating instruction that just deals with fires alone. So, we can have damage --

MEMBER BLEY: But it is still controlled out of the control room?

MR. BOTTORFF: Yes, sir, that is

100-percent controlled from the control room, fire brigades putting out a fire; we are dealing with the plant.

We can sustain damage from a fire without necessarily damaging the safe shutdown equipment. The minute that we see safe shutdown equipment affected with erratic indications in the main control room, pumps starting, things like that, then the shift manager and the unit supervisor will declare an Appendix R fire. And those are the initial entry conditions into that abnormal operating instruction --

MEMBER BLEY: And you might not have had a reactor trip?

MR. BOTTORFF: That is correct.

MEMBER BLEY: Good. That sounds better to me.

MR. BOTTORFF: But, then, we will trip. Now our Appendix R fire procedure, it does override our other emergency procedures. So, once safe shutdown is affected, those Appendix R, they take precedence.

MEMBER BLEY: But, if somehow a fire had created a LOCA or something like that, you would still stay in a LOCA procedure dealing with it, right? Or you tell me. You would get out of the EOPs, period, if you have actuated these fire procedures?

MR. BOTTORFF: The fire procedures take precedence over our normal procedures, yes, sir. But, in an analysis, the fire would not cause a LOCA.

MEMBER BLEY: There are no valves that could be opened by a fire that could move to a LOCA?

MR. BOTTORFF: All our emergency procedures -- I'm sorry -- the Appendix R procedures, then, they deal with the effects of that fire.

MEMBER BLEY: So, if that fire somehow opened a path, that Appendix R procedure actually would make sure you have safety injection going?

MR. BOTTORFF: That is correct.

MEMBER BLEY: Okay. I haven't seen that kind. Okay. Okay. So, they really are EOPs, when you get into them?

MR. BOTTORFF: The Appendix R, yes, sir.

MEMBER BLEY: As well as dealing with the fire? Okay.

MR. BOTTORFF: And assure safe shutdown, yes, sir.

MEMBER BLEY: Okay.

MR. FRUMKIN: And along those lines, the manual actions at Watts Bar are preventive, and there is a thorough analysis area by area or analysis volume by analysis volume where, if they could get a spurious actuation that would open up a valve, that would create a LOCA, even before such a LOCA were to occur, they would go and perform the manual action to isolate it or to de-energize it, such that the LOCA wouldn't occur.

But, then, that kind of gets us to T equals zero. If that LOCA were to occur at T equals zero, then there would be time zone C there to perform the action, and that is the demonstrated time to actually perform the action. So now, we are in a race sort of between your LOCA and the operator.

T1 at the end of zone C is when the operator is done, and T2 at the end of zone d is when the LOCA would reach an unrecoverable condition.

MEMBER BLEY: Okay.

MR. FRUMKIN: And for time margin at TVA, zone D is never less than 10 minutes, and it is always twice the implementation time, except there are some exceptions to that.

MEMBER BLEY: And you guys on the staff have convinced yourself, for all the Appendix R scenarios you have looked at, that T2 minus T1 being greater than twice T0 to T1 more than makes up for any margin you would have needed for your zones A and B, up on this thing? You are pretty comfortable with that?

MR. FRUMKIN: Yes.

MEMBER BLEY: Okay.

MR. FRUMKIN: But D is greater than equal to C because D is their extra time.

MEMBER BLEY: But you said these always are at least twice --

MR. FRUMKIN: D, then I misspoke.

MEMBER BLEY: I'm sorry, I heard you say that --

MR. FRUMKIN: Okay.

MEMBER BLEY: -- and I heard them say that this morning.

MR. FRUMKIN: Okay. I misspoke. D is always greater than C. So, C is your 100 percent. That's how much your time. That is your feasible time.

MEMBER BLEY: The margin is not always twice the time? The margin is at least equal to the implementation time?

MR. FRUMKIN: You have at least 100-percent extra time after you implement it.

MEMBER BLEY: Okay.

MR. FRUMKIN: So, I can't tell you how many conversations we had with TVA. "What two times, a hundred times, a 100 percent, 200 percent, 300 percent?" It would go back and forth, because

100-percent margin, is that 100 percent over -- is that twice the amount of time you need or is that exactly the amount of time you need?

MEMBER BLEY: Where I really wanted you to focus, given what you are presenting is what they did, and it is my understanding from what I heard this morning of what they did, you are convinced, even for cases where C is reasonably short for that particular fire, that D more than makes up for what would be an A and B, if you evaluated them appropriately?

MR. FRUMKIN: When you dig into NUREG-1852, it dances around this idea of a factor of two.

MEMBER BLEY: But I don't care about the dance.

MR. FRUMKIN: Right.

MEMBER BLEY: What I care about is your judgment about what they didn't put into the analysis and whether that left them enough margin, D, to cover those things they left out. And you looked at what was left out and thought about it some?

MR. FRUMKIN: As far as we know, there was nothing left out.

MEMBER BLEY: Well, B is left out.

MR. FRUMKIN: Oh, yes, it more than makes up for B because the time for B is the recall time, and we expect the operators to be on callback.

MEMBER BLEY: Okay. And as a fire protection engineer, you've convinced yourself that A is very small?

MR. FRUMKIN: Well, from a practical matter, we can't do anything with A because we don't know there's a fire yet.

MEMBER BLEY: I have seen designs where a fire could exist long enough, such that by the time you knew it was there, you could be in real trouble. And what I heard them say, and what I thought I heard you say, is you are convinced by the coverage of fire and smoke alarms that that can't happen here, that you will know about the fire well before any damage has occurred beyond the source.

MR. FRUMKIN: That's correct. And that is really a -- well, it is not Watts-Bar-unique, but it is Watts-Bar-specific in the amount of detection that they have.

MEMBER BLEY: Does this embed an assumption that the detectors are 100 percent, you know, going to work 100 percent of the time? Or have you convinced yourself there's enough detectors that, even if that doesn't happen --

MR. FRUMKIN: Yes.

MEMBER BLEY: -- you will still know?

MR. FRUMKIN: It is based on the credit for the detectors, yes.

MEMBER BLEY: Okay.

MR. MOULTON: And this is Charles Moulton.

Additionally, in those areas where they only have a single zone of smoke detectors, or there is equipment that might cause a rapid plant trip, they have added additional time to zone C to account, for example, for the areas that only have a single zone of smoke detector, the time to send an operator up there.

MEMBER BLEY: Okay. So, they have padded that time?

MR. MOULTON: They padded C.

MEMBER BLEY: With what you call B?

MR. MOULTON: Right.

MEMBER BLEY: Where B might be substantial, C is kind of taking care of it, or what we called A and B up there together could be substantial.

MR. MOULTON: Right.

MEMBER BLEY: They padded that. Okay. And you've looked?

MR. MOULTON: Yes.

MEMBER BLEY: Okay.

MR. FRUMKIN: And I'll just add that the idea of very small times was a concern to me. And TVA was like, well, what's twice 25 seconds; what's twice a minute and a half? That doesn't give a lot of comfort that they can do it.

MEMBER BLEY: No.

MR. FRUMKIN: So, that is why they always have at least 10 minutes in C or I guess in D, the time margin. So, it is a factor of two, not less than 10 minutes.

MEMBER BLEY: Okay.

MR. FRUMKIN: And this was looked at specifically during the inspection, and TVA was able to demonstrate that under their procedures they could meet that.

MEMBER BLEY: Okay. Thank you.

If we just go to the last slide -- and we have kind of talked through this to some extent -- but this is a manual action. It is a 60-minute manual action. The operators can do the action in less than 13 minutes. And then, they would be left with over 47 minutes of margin or almost three times the demonstrated time.

This is fairly typical. Many of the

actions that the staff reviewed have more than 40 minutes of time margin, which, again, is far in excess of where 1852's factor of two comes in.

MR. POOLE: That's all. That is our presentation. Are there any other questions?

CHAIRMAN RAY: Anything else?

(No response.)

Thank you.

The agenda shows that we would not take a break until three o'clock. If it is all right with everybody, we will probably break around 2:30, just to make the afternoon a little more even in terms of parts.

All right.

MR. POOLE: So, as you heard earlier, TVA described their design and the testing that they did in order to close out Open Items 63 and 93 on the Eagle 21 Communications. They were on here from the I&C Branch and NRR, who looked at those test results as well as the inspection report that was issued by the Region, when the Region had people out there observing the tests as it was occurring.

So, I will turn it over to Dave.

MR. RAHN: Okay. Yes. As Justin mentioned, I am David Rahn. I am a Senior Technical Reviewer in the I&C Branch in the Division of

Engineering in NRR. And I was the coordinator of the I&C input into the Safety Evaluation Report for Watts Bar Unit 2.

As Steve Hilmes earlier described, they did the test. But, prior to doing that test, Charlie was asking the right questions regarding configuration control of these cards.

Back in 2010, we had performed an audit of the Westinghouse design process at Westinghouse's facility for the Eagle 21. And we noted that there were actually configuration drawings showing the jumper positions and the integration of the serial-to-Ethernet controller, as Steve described. So, that is a permanent thing on the drawings that Charlie was concerned about.

The other issue I wanted to mention was that, just to not confuse it with a different open item we have regarding communications, I found a better drawing that might help you describe this rather than the larger one that shows the Foxboro equipment is more for the integrated control system. Yes, I will give it to you for the record, so you can have it for the documentation.

But there is a drawing that shows better the Eagle 21, the 14 cabinets of Eagle 21, how they go through the serial-to-Ethernet converters, and then, their signals are aggregated into a PC that is part of the process computer system. So, it shows it is really separate from -- it is on the protected side of the data diode that you were describing this morning. So, I think it is a better figure.

So, what we did is we evaluated the description of the test. Prior to the test, I went over it with Steve and other representatives of the site. And so, we reviewed their test plan, test setup, and then, we also had someone in Region II help to monitor the actual result.

So, Region II wrote up their test inspection results in an inspection report. And then, what I did is I coordinated the writeup with our evaluation, and our Supplement 27 will have a better description of what that test is.

So, I agree with Member Brown in that the report that we received was very confusing, but I think what I tried to do is I tried to convert their words into the words that we had previously used in the Safety Evaluation Report. And, hopefully, it reads better than what you had received.

But, overall, we found that this particular item for Eagle 21, at least these two open items can be closed. There is still another open issue yet regarding conducting of a data storm test. And we are anticipating receiving a test plan for that to occur.

That test can't really occur until most of the equipment is up and operating, and there is more construction and installation yet to be done before they can actually conduct that test.

MEMBER BROWN: But that is largely a failure of a process computer or something like that that just starts spitting data out at some configuration --

MR. RAHN: Right.

MEMBER BROWN: Ah, you're still here? I had another question for you.

(Laughter.)

MR. RAHN: Yes. That's good, yes.

MR. HILMES: Yes. Steve Hilmes.

The data storm item that is the open item is to our DCS system --

MEMBER BROWN: Correct, yes.

MR. HILMES: -- which is separate from this. It is our non-safety-related control system.

MEMBER BROWN: He coughed and I didn't hear that. DCS is? Remind me.

MR. HILMES: Distributed Control System.

MEMBER BROWN: Distributed. Oh, right. Okay.

MR. HILMES: We call it, we use the Invensys system, Foxboro.

But you're correct. One of the failures that we try to protect against is some type of hardware failure that starts creating a data storm into the system. And we want to ensure that we don't take down that system with that data storm. So, that is an additional test we will perform later.

MEMBER BROWN: Okay. Can I ask you the other? I need to re-ask a question because in the short interval between this morning and now I have forgotten the answer.

(Laughter.)

I asked you about the Eagle 21 system being within the Level 4. Then, I asked you about all those little red boxes that were called firewalls.

MR. HILMES: Yes.

MEMBER BROWN: And those are different? Those are not Eagle 21? That is a separate -- and you said they were -- I'm trying to remember what type of firewalls they were. Were they software-configurable or were they are hardware-configurable? I am trying to remember. I thought you said that they weren't software. You started to use a word like firmware, but it was like they were hard-programmed or something.

MR. HILMES: The TAPs, which are those particular firewalls --

MEMBER BROWN: Okay.

MR. HILMES: -- in all cases are firmware-configured, or you cannot alter them through software. There are other firewalls in there that are configurable. It depends on the importance of the equipment.

MEMBER BROWN: So, not all of these little red boxes are the same?

MR. HILMES: No, they are not.

MEMBER BROWN: All right. That's what I missed. Okay.

MR. HILMES: No.

MEMBER BROWN: I meant to ask that this morning.

MR. HILMES: For example, the Foxboro system or the DCS, which is not safety-related, has a firewall in it, a classic firewall.

MEMBER BROWN: Software-based.

MR. HILMES: Software-based.

MEMBER BROWN: But it is still within the

Level 4 --

MR. HILMES: It's --

MEMBER BROWN: You're not broadcasting, you're not transmitting that outside --

MR. HILMES: Oh, no, we are not --

MEMBER BROWN: I don't want to say this and get the wrong impression. It is under supervised control because it is within the Level 4 or Level 3 boundaries?

MR. HILMES: It's within the Level 3 boundary --

MEMBER BROWN: Okay. Well, that's all I -- it is just a control-of-access issue --

MR. HILMES: Right.

MEMBER BROWN: -- that I'm trying to get to. There are certain things you want to be more hard-protected than others.

MR. HILMES: Yes.

MEMBER BROWN: And I won't say I'm not as worried about those. It is just that not going to work on that one as hard; that's all.

MR. HILMES: If it performs a safety protection function, it will have data diode or, like Eagle, it just physically cannot talk.

MEMBER BROWN: Okay.

MR. RAHN: That's what we have.

MEMBER BROWN: Thank you.

MR. RAHN: And that is all I have.

CHAIRMAN RAY: Charlie?

MEMBER BROWN: Hey, I'm happy. Thank you. I'll probably forget this again, but, with my age, that happens everywhere. Every minute it happens.

(Laughter.)

CHAIRMAN RAY: All right, we're making up time here. So, that's good. We are 15 minutes head. Let's go ahead, then, with the PAD4.

MR. POOLE: Okay. I'm going to go over the description of what the staff did for the review of PAD4TCD.

Again, you heard TVA's description earlier, some of the history as to why the need for a PAD4TCD version of PAD4.0 was required.

But, essentially, in SSER 23, the staff noted that the thermoconductivity model used by TVA, i.e., PAD4.0, did not account for this degradation. The open item expressed the need for more information to demonstrate that PAD4 can conservatively calculate the fuel temperature and other variables, such as stored energy, given the lack of fuel thermoconductivity degradation model.

As TVA described earlier, TVA's resolution of this open item in the end ended up being to work with Westinghouse to submit a new PAD fuel performance data using the PAD4TCD model, which, as TVA described earlier, does include explosive modeling with thermoconductivity degradation.

This model, although not generically approved by the staff, through a review of a Topical Report, has been used in previous applications by the staff or staff has reviewed it before. TVA mentioned there was an extended power uprate for one of the plants, Turkey Point, where they used this same modeling technique.

Because, as TVA mentioned earlier in their presentation, this is a generic issue with the industry. A number of plants use PAD4.0. And therefore, there were some actions taken; i.e., the information notices that were put out and some other actions to ensure that the operating fleet was okay.

So, for Watts Bar Unit 2, the staff performed a confirmatory analysis similar to that that was performed during the Turkey Point review, which demonstrated that there was a good agreement between PAD4TCD and FRAPCON 3.5, which is the modeling code that the staff uses for the fuel design and planned to be used in the initial loading for Watts Bar Unit 2.

Based on the staff's previous review of PAD4TCD done during the Turkey Point EPU and the confirmatory analysis performed on Watts Bar Unit 2 fuel, staff is satisfied that the concerns previously documented in SSER 23 have been addressed and considers Open Item 61 to be closed.

As you heard from TVA during their presentation, the staff is proposing a license condition associated with the use of PAD4TCD to limit it such that it would only be during the initial fuel cycle. A similar license condition had been applied to Turkey Point as well in their granting of the EPU.

The overall idea, as again alluded to from TVA's presentation, is that Westinghouse has submitted PAD5.0. Staff is currently reviewing PAD5.0, and assuming that it gets approved, the push is to get the operating fleet and, obviously, Unit 2 to move towards the use of PAD5.0 and not this, you know, one-off of PAD4.0.

Any questions?

CHAIRMAN RAY: All right.

MEMBER SCHULTZ: Justin, so the evaluation was done focusing on Unit 2 fuel design --

MR. POOLE: Yes.

MEMBER SCHULTZ: -- with the comparisons, looking at the fuel performance evaluation, FRAPCON/PAD4TCD?

MR. POOLE: Correct.

MEMBER SCHULTZ: Similar to what was done with Turkey Point?

And the schedule associated with PAD5 review is such that there will be time for the LOCA analysis to be redone with PAD5 prior to cycle 2? That is what you are presuming?

MR. POOLE: That is the presumption.

MEMBER SCHULTZ: Or that is what the licensing condition presumes?

MR. POOLE: Correct. I mean, Mr. Koontz mentioned probably the latest and greatest information that I was aware of --

MEMBER SCHULTZ: Yes.

MR. POOLE: -- as far as the schedule for that getting approved.

In the scenario where PAD5 does not get approved before TVA needed to submit their reload analysis for the second cycle, you know, the staff would consider, again, the use of PAD4TCD, but they would have to, again, provide that information for the new core or the next core load, and the staff could do another confirmatory analysis.

But the preference is to go to PAD5 --

MEMBER SCHULTZ: Right.

MR. POOLE: -- if approved.

MEMBER SCHULTZ: But there is a fallback opportunity, if necessary?

MR. POOLE: Either way, we are going to need a license amendment from TVA to either go to PAD5 or, if not available, rejustify to us why PAD4TCD works for the next fuel --

MEMBER SCHULTZ: Turkey Point and Watts Bar are the only licensees in this position or are there others as well?

MR. POOLE: I want to say there is one other, but I can't recall who else it was.

MEMBER SCHULTZ: It's okay.

CHAIRMAN RAY: Is it both Units 1 and 2?

MR. POOLE: It is just Unit 2.

CHAIRMAN RAY: That's what I gathered, but I wasn't sure.

MR. POOLE: Yes. But, again, the idea was, I mean, the condition still exists for Unit 1, but, as Frank mentioned, Mr, Koontz mentioned earlier, there is enough margin in there, as opposed to some other plants in the fleet, that we understand that it is accounted for. And again, there's sufficient margin.

But, when Unit 1 was to come in with a new licensing action related to the fuel, the push would be in that license amendment request to also upgrade to 5.0, whenever that -- assuming it is approved.

CHAIRMAN RAY: All right. If nothing more then, we are ready, but we are going to take a break now because there's not that much remaining after we get back from the break. So, we will go to 25 minutes after 2:00. We can get coffee or whatever.

We will stand in recess until 25 after two o'clock.

(Whereupon, the foregoing matter went off the record at 2:08 p.m. and went back on the record at 2:30 p.m.)

CHAIRMAN RAY: Okay. We're a little late getting back, getting started here again. Let's get to it. We're back on the record.

And GDC-5, I guess, huh?

MR. POOLE: Right. I will go over how the staff closed out Open Item 91, which related to raw cooling water, and how that system and, then, eventually, the others systems we found to meet the criteria of GDC-5.

So, in SSER 23, the staff had documented its review of the Emergency Raw Cooling Water System. In that review, the staff was able to come to the conclusion that the system meets the requirements of GDC-5 by reviewing information that had been provided in the RAI response.

During that review, the staff created Open Item 91 for TVA to update the FSAR to include the discussion that was presented in the RAI response, or at least a summary of the discussion provided in the RAI response.

This was to ensure that the requirements of GDC-5 would be taken into account for any future design changes that TVA may do under, say, the 50.59 process.

Over the four amendments that are shown in the second bullet, Amendments 102, 105, 107, and 112, TVA has updated the FSAR for not just the ERCW, but also component cooling water and the ultimate heat sink section as well.

In taking all these changes into account, the staff is satisfied that the wording in the FSAR ensures that the ability to bring the non-accident unit to cold shutdown is now included in the requirements for the system. And as such, when making future changes, these requirements will be taken into account by TVA. Therefore, the staff has closed Open Item 91.

Now, as mentioned earlier by TVA during their presentation, during review of the most recent RAI responses from TVA, the staff raised a question on the possibility of needing to return to hot standby in the non-accident unit, if less than 24 hours had occurred in the non-accident unit, to allow decay heat to subside.

Given the proposed tech specs that TVA has submitted up to this point, the mode change would not be allowed. TVA is intending to provide the staff with its resolution to this issue, which, as they mentioned earlier in the presentation, is a modification to their proposed tech specs. So, the staff considers this to be an open item under the tech spec review that is still ongoing.

MEMBER SKILLMAN: So, it is open under tech specs, but it is closed as item 91?

MR. POOLE: Correct. So, like I tried to lay out before, in SSER 23, we found that the systems meet the requirements of GDC-5, but we had based all that off information in an RAI response. And there was nothing at that time that existed in the FSAR pointing to those systems needing to meet the requirements of

GDC-5.

So, that was really the nexus of that open item, was to ensure that there was at least something in there, like I said. So, as they make changes in the future, they recognize to account for that and not gloss over that fact.

So, TVA has done that. They have put what we have found to be a sufficient amount of information in the FSAR to ensure that. But, in doing our review, like I said, of the last RAI response, this question came up about, well, your tech specs say you can't change modes in this situation, but in your response you said that you may have to. So, how are you going to handle that?

Like I said, in discussions with TVA, they are proposing a modification to their tech specs which we have not yet seen. So, we are putting that in the category of our review of the tech specs.

MEMBER SKILLMAN: So, it will be a return to mode 3 for a limited time period or something such as that?

MR. POOLE: That's what we believe. Again, we haven't seen anything yet from TVA, but, once received, we would do our review and go from there.

MEMBER SKILLMAN: Okay. Thank you.

CHAIRMAN RAY: Any other questions?

(No response.)

All right. Thank you.

MR. POOLE: Okay. Moving on to the closure of Open Item 59, again, in SSER 23, Section 6.1.1.4, the staff noted that TVA modified FSAR Section 6.1.1.1, which was the material section and fabrication, to add the following sentence to the paragraph discussing the compatibility of the ESF system materials with containment spray and core cooling water in the event of a LOCA. And this is the following paragraph that was added to the FSAR.

Quote: "Note that qualified coatings inside primary containment located within the zone of influence are assumed to fail for the analysis in the event of a loss-of-coolant accident. The zone of influence for qualified coatings is defined as a spherical zone with the radius of 10 times the break diameter."

Since this was something that the staff was currently reviewing under the umbrella of Generic Letter 2004-02, staff created an open item tying these two together, meaning we were trying to make sure that the assumptions made that are being added to the FSAR are the same assumptions that are being made in its response to the Generic Letter. And then, if found acceptable during the review of the Generic Letter, the addition of the wording to the FSAR would also be found acceptable.

So, the staff completed its review of Generic Letter 2004-02 for Unit 2 and issued its closeout letter on September 18th, 2014. In general, the staff found that the debris did not inhibit the ECCS or CSS performance of its intended function, in accordance with 10 CFR 50.46, to assure adequate long-term core cooling following a design basis accident.

More specifically, in Section 3.2.8, "Coatings Evaluation of the Safety Evaluation," staff found that the assumptions made in the Generic Letter response matched the statements made in the FSAR; i.e., the qualified coatings within a radius of 10 times the break diameter are assumed to fail.

In the staff's evaluation of Generic Letter 2004-02, it was concluded that TVA appropriately identified the various protective coatings that can be a source of debris inside the containment building following a postulated break in site containment, and therefore, TVA's evaluation of coatings was found acceptable.

Since the wording added to the FSAR match what was reviewed and found acceptable during the review of the Generic Letter, the staff considers Open Item 59 to be closed.

CHAIRMAN RAY: Okay. Now I think maybe TVA can add to the record at this point.

MR. KOONTZ: Yes, this is Frank Koontz.

CHAIRMAN RAY: Good.

MR. KOONTZ: Chairman Ray asked a question earlier this morning about 200 square feet in relation to tapes, tags, and labels. We have tracked that down. It is in the NRC SER, and there is potentially an area for confusion in just reading the wording there.

It was related to an RAI response that we provided to Commission staff. I just wanted to read a portion of that. This is a RAI response dated April 29, 2011, and it was on the sump issues.

The question had to do with a 750-square-foot sacrificial strainer area for miscellaneous debris. As you recall, when I mentioned it earlier, we had 1,000-square foot allowance for tapes, tags, and labels. Then, we applied a packing factor, which is allowed under NEI 04-07, that brought it down to 750 square feet.

Our conservative 3-dimensional

computational fluid dynamics model predicted that material could reach the sump strainer. And so, when we designed the sump strainer, we allowed for that amount of square feet of tapes, tags, and labels.

And we also compared that to what we saw over in Unit 1. When we walked down Unit 1, we found they had 697 square feet of tapes, tags, and labels, which showed we had some margin to our packing ratio at least, or 1,000 square feet and our 750 square feet.

MEMBER BLEY: On one day.

(Laughter.)

MR. KOONTZ: Yes, yes.

The RAI response asked this question about how did that relate to a 200-square-foot area that was assumed in testing, not in the analytical modeling but in testing. And what we indicated was that, although the allowance was the same for Unit 2 for the 1,000 square feet reduced down to 750, it was later determined that this type of debris does not get transported to the sump screens due to the geometry of the containment. And thus, the final test, the prototype test, did not include these types of debris.

The Unit 2 strainer surface area is 4600 square feet, as I mentioned in the presentation. It says, "For the purpose of test scaling, the total surface area was assumed to be only 4400 square feet in order to add 200 square foot of margin to the strainer flow test results."

It goes on to say, "The AREVA debris allocation table for the Unit 1 strainer performance test erroneously stated this 200 square feet was removed for tapes, tags, and labels. This 200 square foot does not represent a direct correlation to signs, placards, tags, and tape, but, as described above, was an assumed clean strainer area reduction to provide margin."

So, although those two weren't related, that was where the area of confusion, I guess, existed a little bit. It is not really that we reduced the 1,000 or the 750 down to 200. It is just we determined that these things actually can't get to the strainer during testing. And in order to provide an additional margin for the test, they took an additional 200-square-foot penalty.

So, I just wanted to clarify that. We have provided the RAI response to the Subcommittee, so that you can put that in your records. And we have also provided a path to the SER on the containment sump for Watts Bar, so that that is available to the Subcommittee also.

CHAIRMAN RAY: Any questions of TVA?

(No response.)

MR. KOONTZ: Thank you.

CHAIRMAN RAY: Thank you.

Okay, Justin, go ahead.

MR. POOLE: That's all I have for Open Item 59.

CHAIRMAN RAY: All right. Any questions from the members?

(No response.)

Hearing none, then, we can go ahead to the conclusion.

MR. POOLE: Okay. Next slide.

So, the last slide here is just to give an overall idea of project status and some upcoming milestones that we have in the future.

As mentioned earlier by Michele, the staff's review is nearing completion. There is a small number of open items remaining. Most are either inspection-related or involve minimal staff review.

As you heard from Bob Haag, there was an increase in inspection activity for the last year, and that additional higher level of activity is expected for this coming year.

In February, we have scheduled the full

Committee meeting with ACRS on the 5th. We intend to talk to those items that have been updated since the last full Committee meeting, which occurred in November of 2013. I must get other direction.

We continue to review TVA submittals, primarily focused on closing out of the remaining open items.

We plan, as mentioned by Michele earlier, we plan on putting up a Commission Vote Paper in the spring, when deemed appropriate by management, to request from the Commission the authority to issue the operating license when we feel all the final actions have been met.

Some of those actions are listed above in the Operational Readiness Assessment Team Review, which Bob Haag mentioned earlier, and the Region's readiness for their assessment of overall construction inspection and readiness for the fuel load.

And that is all I have.

CHAIRMAN RAY: Okay. We have deliberately not, although the staff necessarily in what it is doing will be looking at selected Fukushima items, we have not done so, so as to not have any last-minute involvement in things that are still pending or in the process of being resolved for all plants. This would be a place where we might get involved in requirements as they are being imposed on all plants, just because this is a case where we have the second unit of the dual-unit plant coming forward.

So, the bottom line is I just want to say we have not engaged in review of Fukushima items here at all, and I don't expect that we will before we issue our letter on the operating license.

Are there any other questions for staff before we excuse them and go through the wrap-up?

(No response.)

If not, we will begin our conclusion by taking any public comments. And I believe Girija has gone to open the phone line for that purpose. And until we are ensured that it is open, we will ask if there are any members of the public here in the audience of this meeting who would like to come to the microphone and make a comment at this time.

(No response.)

Seeing none, and in order to check if the phone line is open, if there is anyone on the line, whether you want to ask a question or not, could you just speak up and advise us that you can hear us and we can hear you?

(No response.)

I hear no comment. I guess I've got to make sure that the line is open, Girija not being here. He is perhaps trying to verify that.

We will assume it is open and that no one wants to make a comment, but I will try again if I find that the line wasn't open.

But, so we don't hold people up any further, I will begin the last step of the process, which is to go around and seek input from members of the Subcommittee today.

So, Pete?

MR. SHUKLA: I am going to make the line open.

CHAIRMAN RAY: Yes. Oh, is it open?

MR. SHUKLA: No, it is opening now for the members of the public.

CHAIRMAN RAY: So, I advised that the line, we are still in the process of trying to get it open.

(Pause.)

What's the story?

MEMBER RYAN: He is opening it as we speak. It should be open in a second.

CHAIRMAN RAY: All right. It is a more complicated process, I guess, than I envisioned.

(Laughter.)

Let me try again then. If there is anybody on the phone line still, could you so indicate?

(No response.)

I hear popping, and so on. So, I suppose it is open.

Okay, I don't hear any public comment, having tried once, twice, three times.

So, we will resume where I was before, which is to ask for members of the Committee to provide any comments at this time in the form of deliberation that they would like to give us, so Girija and I can work on a letter.

MEMBER RICCARDELLA: No further comments. It appears a very thorough process by both TVA and the staff, and I hope the project proceeds on schedule.

CHAIRMAN RAY: Thank you.

Steve?

MEMBER SCHULTZ: I appreciate the work and the preparation and the presentations today by both the Applicant and the staff, and have no further comment.

Thank you very much.

MEMBER SKILLMAN: I echo Pete's and Steve's comments. I would, in fact, give kudos to those who created the hydrology review. I reviewed that very, very carefully. I thought that was a very good piece of work.

Thank you.

CHAIRMAN RAY: Thank you.

Dennis?

MEMBER BLEY: I agree with everybody. I would just mention, though, that as a Subcommittee, not everybody is here, and some of the people who might be interested aren't here.

In particular, on the human operator manual actions, I think we and the record showed pretty clearly what was done and how staff looked at that. And it looks reasonable to me, but I think other members may want to review that pretty carefully. So, we can't speak for them.

CHAIRMAN RAY: So, you should be prepared at the full Committee meeting to respond to further questions that may arise there on that subject or any other. But, at this point, that's all we can say.

Mike?

MEMBER RYAN: I would like add just my thought that I thought the briefings were very well prepared and very well presented. So, it was very useful to hear today from all the focus across the entire team that came.

So, thank you very much. Thank you.

CHAIRMAN RAY: Ron?

MEMBER BALLINGER: I have nothing more to add.

CHAIRMAN RAY: Charlie?

MEMBER BROWN: Nothing more. My report I think satisfactory and I didn't disagree with it. So, I guess that is a good result.

(Laughter.)

CHAIRMAN RAY: Indeed.

Okay. With that -- and I have nothing to add, either -- I appreciate the clarification on the sump strainer thing. I hope it will get entirely resolved before full Committee, but do be prepared, if the question comes up at full Committee, to address it once more, as was done here.

And with that, if there is nothing else, we will stand adjourned.

(Whereupon, at 2:50 p.m., the Subcommittee meeting was adjourned.)

Watts Bar Nuclear Plant

ACRS Package

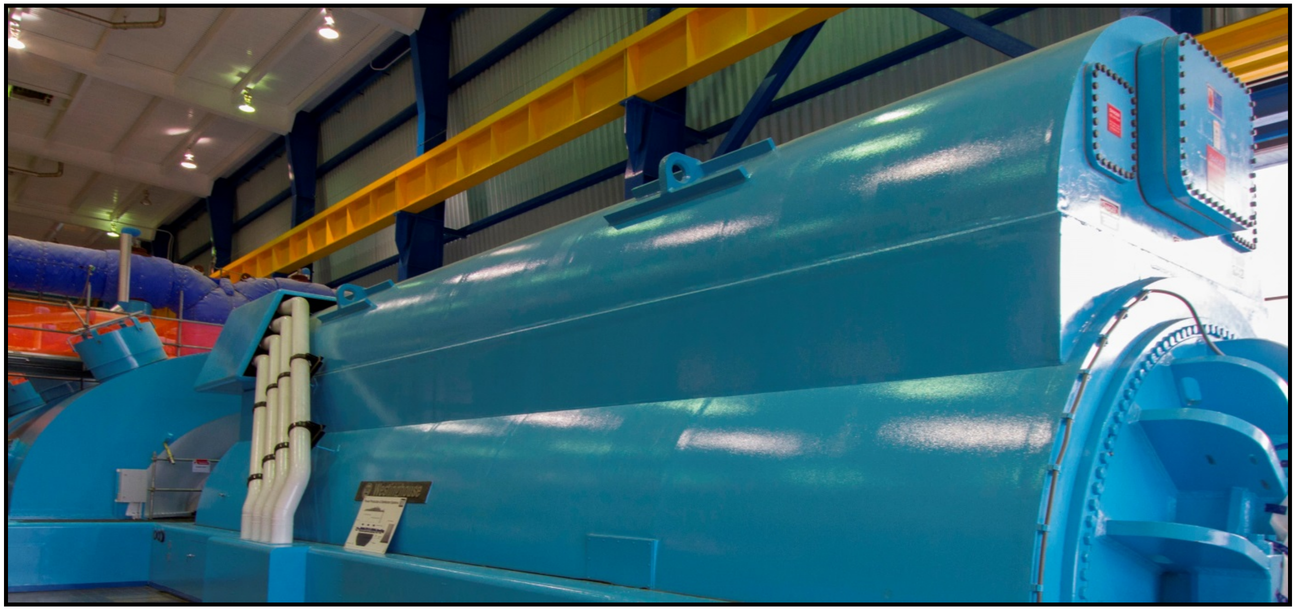
January 13, 2015

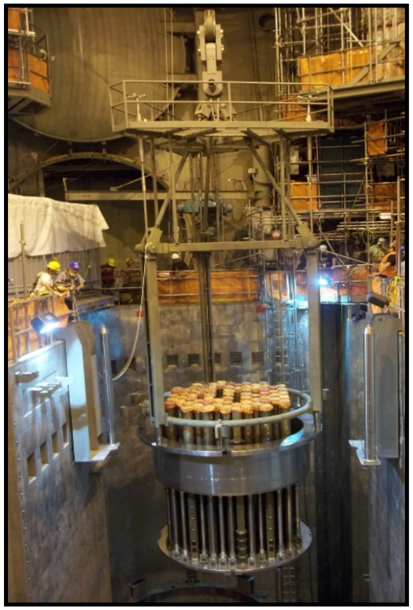
Agenda

- Overview of Watts Bar Unit 2 Project
- ACRS Requested Topics
  - Hydrology
    - Item 133 – Sand Baskets
    - Item 134 – Final Safety Analysis Report (FSAR) Section 2.4.4.1, “Dam Permutations”
  - Fire Protection Report/Operator Manual Action (OMA) Feasibility
  - Item 63 and 93 - Eagle 21 Two Way Communication Testing
  - Item 61 – Thermal Conductivity Degradation
  - Item 91 – General Design Criterion -5
  - Item 59 – Containment Recirculation Sump

Overview of Watts Bar Unit 2 Project

- Guiding Principles
  - Safe and high quality
  - Design basis fidelity with Watts Bar Unit 1
  - Systems, structures, and components rebuilt, refurbished, or replaced





Overview of Watts Bar Unit 2 Project

- Project Update
  - Completed primary cold hydrostatic test
  - Completed secondary steam generator (SG) hydrostatic test
  - Completed secondary hydrostatic test
  - Start ice load – forecasted February 2015
  - Start hot functional testing – forecasted March 2015
  - Fuel load – forecasted June 2015

Overview of Watts Bar Unit 2 Project

- Licensing Status
  - Final Environmental Statement – Complete
  - Safety Evaluation – Nearing completion
  - No Watts Bar Unit 2 Specific Contentions Remain Open
  - Generic Southern Alliance for Clean Energy contention remains regarding "Continued Storage of Spent Nuclear Fuel" Rule
  - Inspection Planning and Scheduling Items ~80% complete
  - Developing Substantially Complete Letter
  - Closure of remaining Licensing Issues

Overview of Watts Bar Unit 2 Project

- Transition and Operational Readiness Overview
  - Operating organization driving transition
  - Unit 1 sharing ownership of critical Unit 2 milestones
  - Staffing at appropriate level
  - Training complete for dual-unit operation
  - Corporate organization providing oversight and support
  - Preparing for Operational Readiness Assessment Team Inspection

Special Topics

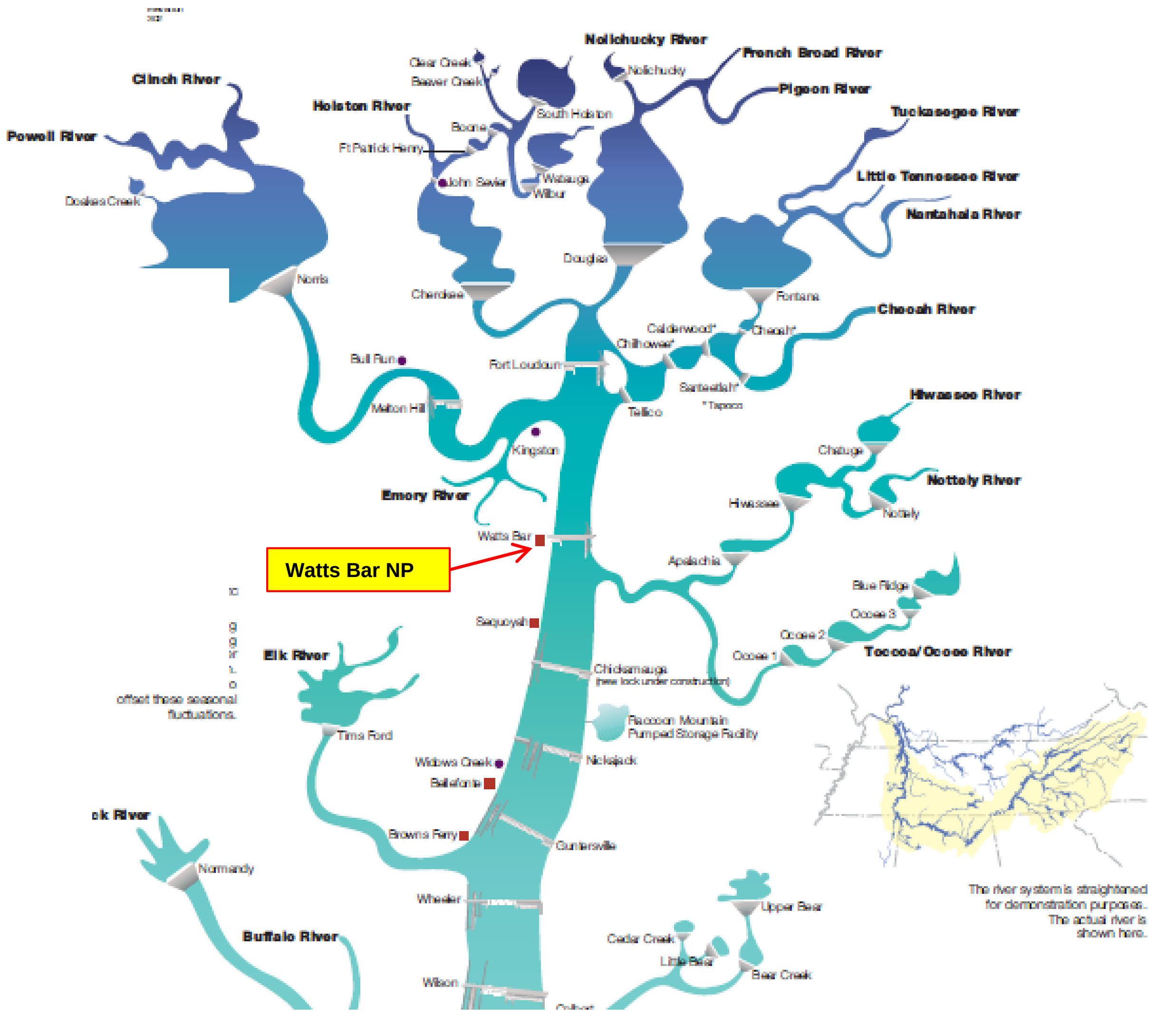
WBN Hydrology - Introduction

Current Status

- TVA has performed a hydrologic Probable Maximum Flood (PMF) analysis of the Tennessee River and tributaries using the industry standard hydraulic modeling tool Hydrologic Engineering Centers River Analysis System (HEC-RAS)
- Dams credited in the PMF simulations have been confirmed stable using current standards or modified
- Dam modifications are complete or will be complete by Fuel Load
- Systems, Structures, and Components (SSCs) required for Flood Mode Operation at the WBN site are protected or designed for submergence
- Several meetings have been held with the NRC staff and two site audits of TVA calculations completed
- There are currently no open technical questions with the NRC staff

Watts Bar Site on Tennessee River

Tennessee River and Tributary Dams



WBN Hydrology - Background

- Licensing basis challenges
  - Input parameter changes (discharge coefficients, etc.)
  - TVA reservoir operational changes
  - Lack of Quality Assurance (QA) documentation for TVA hydraulic model and support modeling software
  - Quality of the documentation of flood simulations and results
  - Dam stability documentation limited in scope and inconsistent with current industry guidelines

WBN Hydrology – Unit 1 License Amendment Request (LAR)

- Unit 1 LAR submitted in 2012 to address these issues
- LAR revised PMF flood level: 739.2 feet
  - Utilized HESCO barriers for embankments at Watts Bar, Cherokee, Fort Loudoun and Tellico to prevent overtopping
  - Major stability modifications at Cherokee and Douglas non-overflow dams to improve margin
  - Implemented plant modifications for protection of SSCs required for Flood Mode Operation
- Unit 1 LAR revised seismic-induced dam failure flood elevation (731.2 feet) and confirmed existing warning time was adequate
- NRC April 2014 audit challenged the PMF dam stability determinations

WBN Hydrology – Revised Approach for Hydrology

- TVA responded to NRC April 2014 audit of 2012 LAR with September 2014 WBN U1 LAR revision
- WBN U1 LAR revision changes for PMF:
  - Utilized HEC-RAS hydraulic modeling tools in lieu of TVA hydraulic model
  - Updated acceptance criteria for global dam stability
  - Conservatively modeled four additional dams as breached instantaneously and completely
  - Defined modifications to credit stability at five dams
- Critical WBN site flood elevation: 738.9 feet but retained 739.2 feet as the design basis flood elevation
- Seismic-induced dam failure flood analysis and warning time unchanged

WBN Hydrology – Basis for Acceptability of Revised Approach

- Revised WBN Unit 1 basis is justified and acceptable for WBN Unit 2 licensing
  - HEC-RAS is the industry standard for unsteady flow flood simulations
  - Dam stability acceptance criteria is consistent with current TVA River Operations dam safety standards
  - Four additional dams not credited; conservatively modeled as complete, instantaneous breaches at the peak elevation of the reservoir
  - Five major dams are being modified to meet current dam stability acceptance criteria
  - SSCs required for Flood Mode Operation can perform their design function under design basis flood conditions

Dam Modifications

Dam	Modification
Cherokee	Post-tensioning non-overflow dam and raising embankment overtopping elevation (removing HESCO barriers)
Douglas	Post-tensioning non-overflow dam and raising embankment saddle dam overtopping elevation; adding saddle dam toe berms
Fort Loudoun	Post-tensioning non-overflow dam (remaining HESCO barriers will be removed following installation of new bridge)
Tellico	Reinforcing the non-overflow dam “neck” and raising the embankments overtopping elevation (removing HESCO barriers)
Watts Bar	Reinforcing the portions of the non-overflow and lock “necks”; raising the overtopping elevation of embankments and flood walls (removing HESCO barriers); lowering the west saddle dam elevation to 752.0 ft

Cherokee – Embankment Dam

Installing roller compacted concrete to eliminate overtopping

Cherokee – Non-overflow Dam

Installing Dowels for Platform

Placement of Flow Fill in Seepage Cutoff for RCC

Drilling on TW-965-12 Anchor Hole

Drill on 28-1 Spillway Anchor Holes

Douglas – Saddle Dam # 1

Installation of Saddle Dam #1 relief wells

Watts Bar – East Embankment Extension

Embankment at Final Grade 8/26/14

Fort Loudoun – Non-overflow dam

Installing post-tensioning in non-overflow dam

Open Issue Resolution

- **Open Item 133 – Sand Baskets**

  In order to confirm the stability analysis of the sand baskets used by TVA in the WBN Unit 2 licensing basis, TVA will perform either a hydrology analysis without crediting the use of the sand baskets at the Fort Loudoun dam for the seismic dam failure and flood combination, or TVA will perform a seismic test of the sand baskets, as stated in TVA's letter dated April 20, 2011. TVA will report the results of this analysis or test to the NRC by October 31, 2011. (SSER 24, Section 2.4.10)

  TVA Response:

  - Seismic-flood hydrological analysis does not credit HESCO barriers
  - Sand baskets (HESCO barriers) are being replaced with permanent structures and will be complete by U2 fuel load except for Fort Loudoun embankment.

- **Open Item 134 - FSAR Section 2.4.4.1, "Dam Permutations"**

  TVA should provide to the NRC staff supporting technical justification for the statements in Amendment 104 of FSAR Section 2.4.4.1, "Dam Failure Permutations," page 2.4-32 (in the section "Multiple Failures") that, "Fort Loudoun, Tellico, and Watts Bar have previously been judged not to fail for the OBE (0.09 g). Postulation of Tellico failure in this combination has not been evaluated but is bounded by the SSE failure of Norris, Cherokee, Douglas and Tellico." (SSER 24, Section 2.4.10)

  TVA Response:

  - SSE + 25 year storm assumed failures of Norris, Cherokee, Douglas and Tellico dams are the controlling analyzed dam failure simulation for impacts at WBN site
  - SSE failures of Douglas, Fontana and Tellico were not analyzed because this combination is bounded by the analyzed dam failure simulation which considers SSE + 25 year storm assumed failures of Norris, Cherokee, Douglas and Tellico dams.
  - Basis: Post-SSE + 25 year storm failure flow through the Norris and Cherokee dams is ~9 times the post-failure flow through the Fontana dam. Also, the storage volume behind the Norris and Cherokee dams is approximately 4 million acre-feet compared to 0.45 million acre-feet behind Fontana dam. Therefore, the analyzed simulation bounds the unanalyzed simulation as stated in the LAR.

Conclusion

- WBN PMF hydrological analysis has been updated to current standards
  - Transitioned to industry-recognized unsteady flow simulation software (HEC-RAS)
  - Updated dam stability calculations to be consistent with current River Operations criteria

- Required modifications will be completed to support the Unit 2 fuel load milestone

- Watts Bar equipment required for Flood Mode Operation under the worst case design basis flood conditions are protected and capable of performing required design functions

Fire Protection Feasibility and Reliability of Operator Manual Actions

- Operator manual actions (OMAs) taken in response to a fire are evaluated according to the guidance in Regulatory Guide 1.189, Revision 2, "Fire Protection for Nuclear Power Plants," and NUREG-1852, "Demonstrating the Feasibility and Reliability of Operator Manual Actions in Response to Fire."
- The following topics for discussion involving the timelines and methods were requested:
  - Fire detection
  - Condition diagnosis
  - Personnel assembly
  - Communications
  - Coordination
  - Supervisor direction
  - Implementation of required actions
  - Transit
  - Assessment of the uncertainties and available time margins.

Fire Protection Feasibility and Reliability of OMAs

Fire Detection

- Cross zone detection (most areas of the plant)
  - No delay for confirmation of fire
- Single Zone Detection with Visual Confirmation
  - Delay Times Accounted for in Feasibility Evaluations
- Fire Reported by Plant Personnel (personnel continuously in buildings)
  - No Delay for Confirmation of Fire
- High Pressure Fire Protection System Initiation
  - No Delay for Confirmation of Fire
- CO_2 System Initiation
  - No Delay for Confirmation of Fire

Result - Early notification of fire development

Fire Protection Feasibility and Reliability of OMAs

Fire Scenario Questions

- **Would a slow, undetected fire disable equipment to prevent safe shutdown?**

  Examples of Engineering and Administration Controls in Place
  - Controlled Combustible Loading Program (permanent and transient)
  - Hot work permit and fire watch procedure
  - National Fire Protection Association code compliant detection and suppression
  - Equipment separation (Regulatory Guide 1.75 and Appendix R)

- **Would a rapid fire force entry Into Appendix R prior to Auxiliary Unit Operator (AUO) availability?**

  No equipment present in area which would result in immediate need to declare Appendix R event
  - Occurs only with accelerant present (e.g., oil filled transformers)
  - Five locations
  - No equipment present in area which would result in immediate need to declare Appendix R event
  - First required OMA in 1 hour

Result – Appendix R response ensures safe shutdown is achieved and maintained

Fire Protection Feasibility and Reliability of OMAs

Condition Diagnosis/Personnel Assembly

- Main Control Room (MCR) diagnoses initial plant response under Abnormal Operating Instruction (AOI) 0-AOI-30.1, "Plant Fires."
  - Dispatch Fire Brigade
  - Initiate personnel assembly
  - Verify high pressure fire pumps running
  - Evaluate fire criteria for entry into 0-AOI-30.2, "Fire Safe Shutdown"

- Auxiliary Unit Operator (AUO) personnel availability demonstrated
  - First AUO available in 3 minutes
  - Second AUO available in 5 minutes
  - Other AUOs available within 8 minutes

- AUOs dispatched immediately upon declaring Appendix R fire

Result – Rapid response to the fire condition

Fire Protection Feasibility and Reliability of OMAs

OMA Performance Times/Uncertainties,

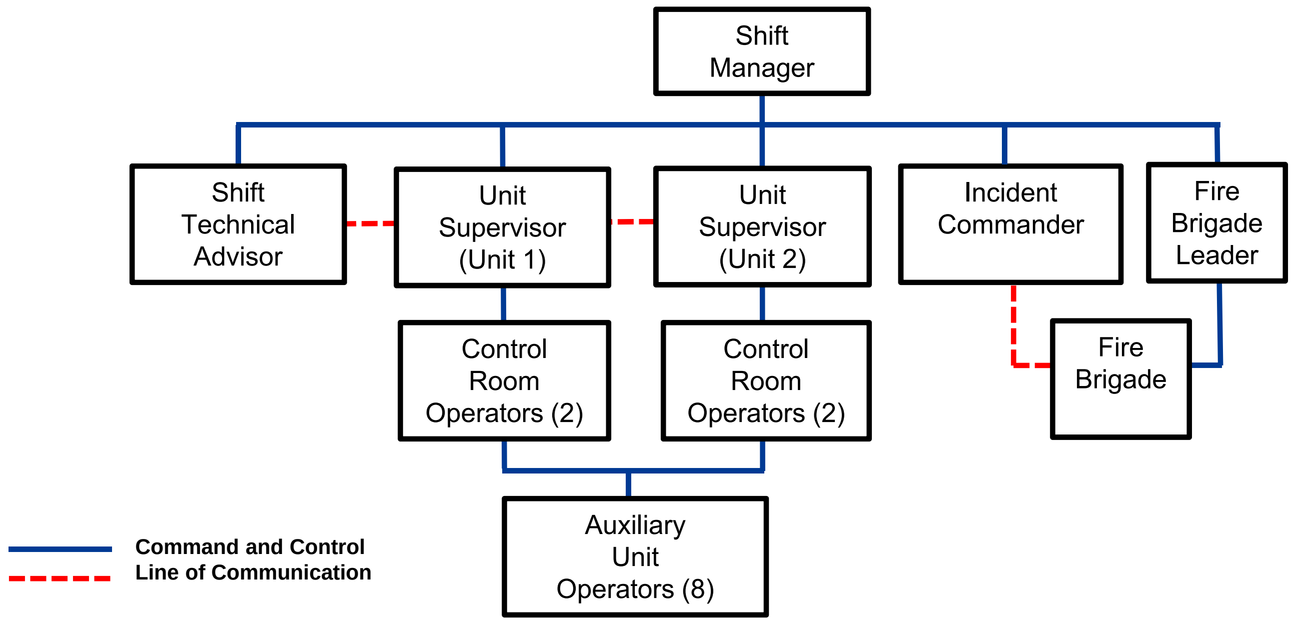
- Appendix R time requirements start when reactor tripped
  - First AUO available performs OMAs with shortest allowed time
  - OMA allowed times include transit time from MCR/ACR and performance time
- OMAs proceduralized and thus do not require diagnostic time
- OMA performance times demonstrated by walkdown
- Feasibility and reliability evaluations accounted for uncertainties such as environmental conditions

Result - OMAs in accordance with NUREG-1852

Fire Protection Feasibility and Reliability of OMAs

Staffing and Training

- MCR and AUO staffing based on total Appendix R actions



- Staff trained on Appendix R procedures and expectations
- Dedicated Fire Brigade

Result – Staff proficient and qualified

Fire Protection Feasibility and Reliability of OMAs

Environmental Considerations

- Lighting on transit paths and OMA performance locations
- Smoke
  - No short-term OMAs in fire area
  - Large rooms provide smoke buffer
  - Specific fire plans for OMAs potentially affected by smoke
- Radiation
  - No OMAs in high radiation areas
  - No short-term OMAs require C-zone dress-out
- No impact from noise since OMA actions proceduralized and AUOs familiar with plant locations
- Sprinklers, temperature, humidity, and proper personal protective equipment (PPE) accounted for
- Environmental conditions accounted for with a factor of 2 margin

Result – Feasibility and reliability evaluations include NUREG-1852 environmental conditions

TVA Fire Protection Feasibility and Reliability of OMAs

Communications

- Two physically separated radio systems
- Verified radios available to support required OMA communications
- AUOs carry radios

Coordination/Supervisor Direction

- Unit Senior Reactor Operator and Shift Manager in overall control of plant
- Incident Commander (SRO) responds to fire location
- Dedicated Fire Brigade and Leader responds to fire

Result – Strong Command and Control

Fire Protection Feasibility and Reliability of OMAs

Dual-unit Demonstration

- Fire affects both units
- MCR actions performed at simulator
- AUO actions simulated in plant
- Demonstrated effective coordination between MCR and AUOs
- Performance times met NUREG-1852 margin criteria

Result – WBN Fire Protection Program capable of supporting dual unit operation

Eagle 21 Two Way Communication Testing

Item 63 – Two-Way Communications with Eagle 21

- TVA should confirm to the NRC staff that testing prior to Unit 2 fuel load has demonstrated that two-way communications is impossible with the Eagle 21 communications interface. (SSER 23, Section 7.2.1.1)

Item 93 – Two Way Communications with Eagle 21 and ICS

- TVA should confirm to the staff that testing of the Eagle 21 system has sufficiently demonstrated that two-way communication to the ICS is precluded with the described configurations. (SSER 23, Section 7.9.3.2)

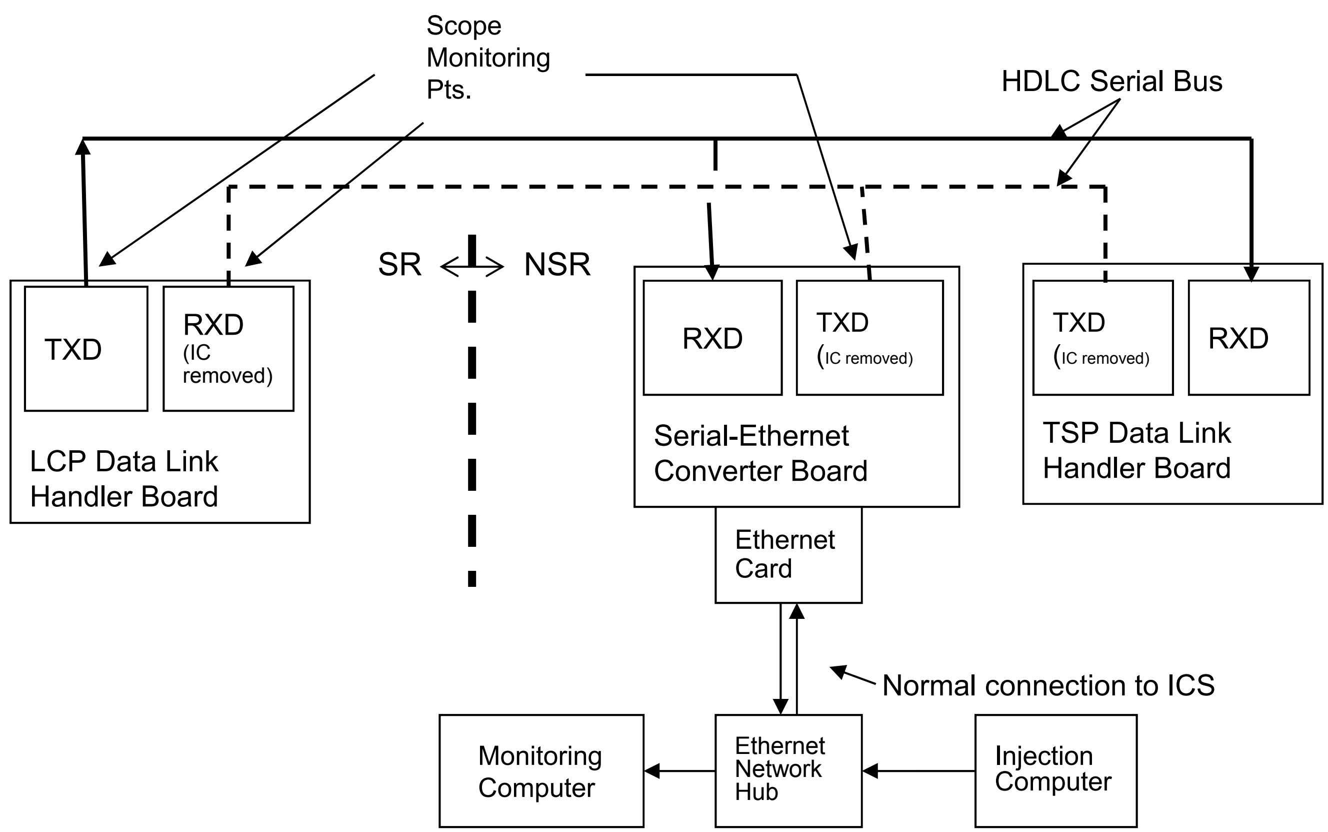
Eagle 21 Two Way Communication Testing

- Eagle 21 is a Firmware based digital system that has an external communications interface for transfer of plant data parameters to the Unit 2 plant Integrated Computer System (ICS).
- Each Eagle Rack is divided into a
  - Loop Calculation Processor (LCP) Subsystem which performs Safety-Related Functions and
  - Test Sequence Processor (TSP) Subsystem which performs Non-Safety-Related functions including communications to the ICS
- The communications interface from the LCP to the TSP is ensured to be unidirectional, since:
  - LCP data link handler (DLH) has no receive Integrated Circuit (IC);
  - TSP DLH has no transmit IC; and
  - Serial-Ethernet converter (SEC) has no transmit IC.

Eagle 21 Two Way Communication Testing

- Testing verified two-way communications is impossible with the Eagle 21 rack.
  - Validated the ICs for transmission of data to the LCP were not installed on the boards.
  - A computer was connected to Eagle 21 Ethernet port and configured to generate a data storm to the Eagle 21 by targeting its IP address.
  - The transmit output from the SEC board to the High Level Data Link Control (HDLC) Bus was monitored with an Oscilloscope. No data was detected.
  - The receive input to the LCP Data Link Handler Board (DLHB) from the HDLC Bus was monitored with an Oscilloscope. No data was detected.
  - The transmit output from the LCP DLHB to the HDLC Bus was monitored with an Oscilloscope to ensure that output data was not impeded as expected.
  - The Ethernet output from eagle was monitored to validate that the data to the ICS was not impeded by the data storm.

Eagle 21 Two Way Communication Testing



Thermal Conductivity Degradation

Open Item – 61

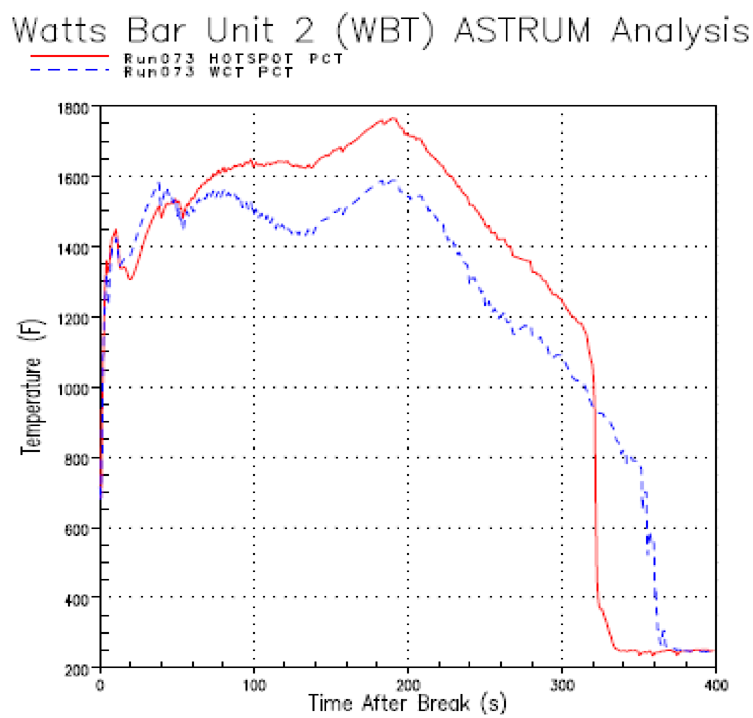
- TVA should provide information to the NRC staff to demonstrate that PAD 4.0 can conservatively calculate the fuel temperature and other impacted variables, such as stored energy, given the lack of a fuel thermal conductivity degradation (TCD) model. (SSER 23, Section 4.2.2)

Thermal Conductivity Degradation

- Watts Bar Unit 2 large break (LB) Loss of Coolant Accident (LOCA) based on Westinghouse codes
  - LBLOCA Best Estimate Code - ASTRUM
  - Fuel Performance (Robust Fuel Assembly 2 fuel) Code - PAD 4
  - Resulted in initial peak clad temperature (PCT) of 1552° F
- NRC issued Information Notice 2009-23 on TCD
  - Vendor safety analyses potentially non-conservative due to TCD
- NRC issued Information Notice 2011-21 on Realistic LOCA models
  - ASTRUM specifically mentioned as potentially non-conservative based on input from PAD
- NRC issues specific letters to vendors

Thermal Conductivity Degradation

- Pressurized Water Reactor (PWR) Owners Group Project to estimate TCD impact
  - Generic estimate based on plant groupings
  - Watts Bar Unit 2 impact of 175˚ F increase projected
  - Resultant Unit 2 peak clad temperature (PCT) - 1727˚ F
- Watts Bar Unit 2 requests Westinghouse to perform specific Unit 2 reanalysis for licensing
  - Uses ASTRUM and PAD4+TCD
  - Results in PCT - 1766˚ F analysis submitted to NRC for review



Thermal Conductivity Degradation

- NRC requests proprietary Westinghouse fuel data
  - NRC performs audit using FRAPCON 3.5
  - NRC approves results for first operating cycle
- Latest Unit 2 PCT with TCD
  - Resulted in a PCT reduction of 55° F
  - PCT 1711° F
  - Margin remains to 2200° F
- License condition for Unit 2 Cycle 2
  - Re-analyze LBLOCA once PAD 5 topical approved by NRC

General Design Criterion 5

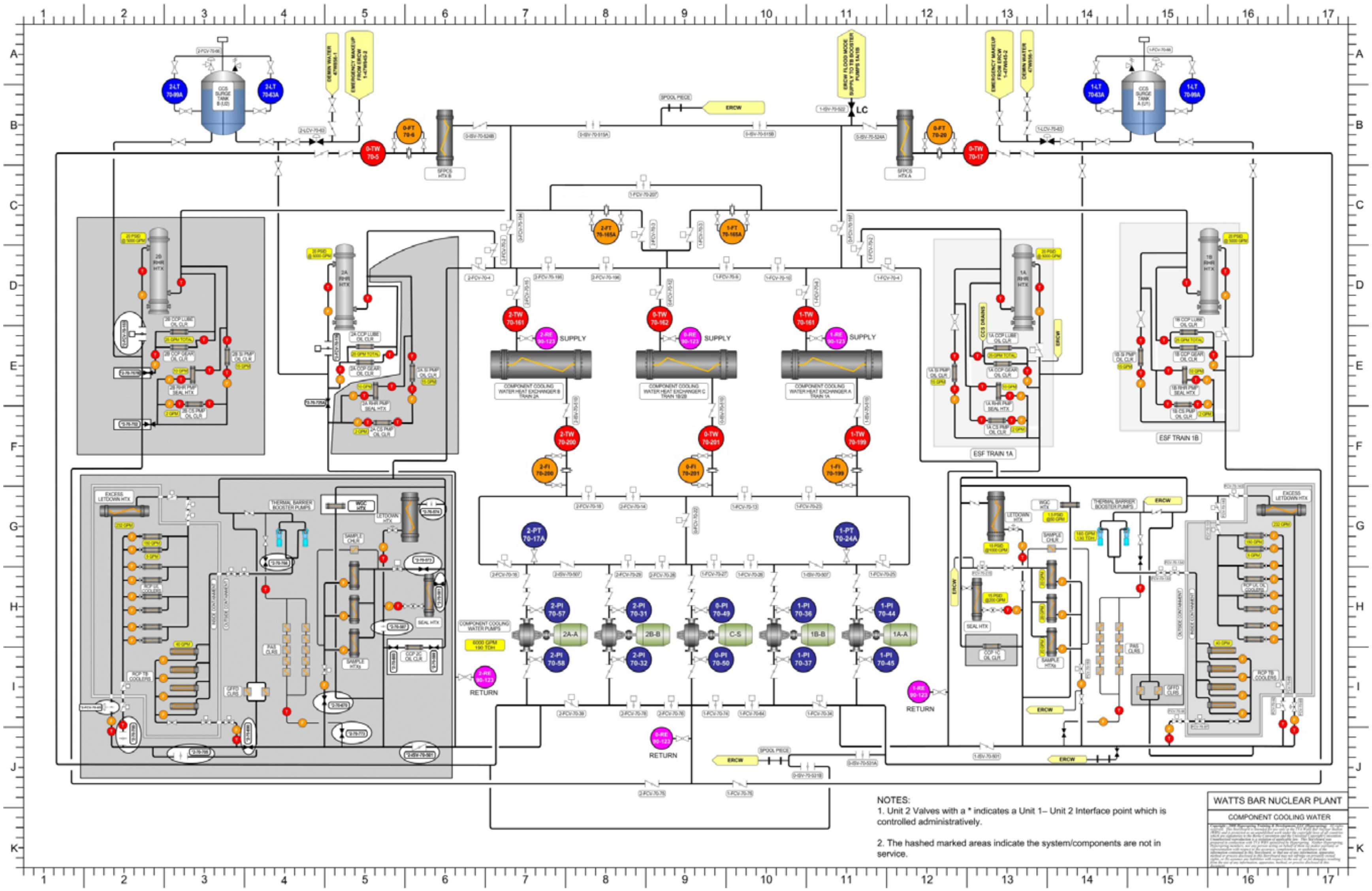
Item 91 – GDC-5

- TVA should update the FSAR with information describing how Watts Bar Unit 2 meets GDC 5, assuming the worst case single failure and a loss of offsite power.
- GDC 5 – Sharing of structures, systems, and components
  Structures, systems and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

General Design Criterion 5

- Design Basis
  - Watts Bar designed as a hot standby plant
    - One unit in accident
    - Second unit can remain safely in hot standby (≥350ºF)
  - Watts Bar has capability to safely handle one unit in an accident and bring second unit to cold shutdown (≤200ºF) within approximately 72 hours

General Design Criterion 5



General Design Criterion 5

- Watts Bar Unit 2 has dual-unit flow models of both Essential Raw Cooling Water (ERCW) and Component Cooling System (CCS)
  - Allows various combination of unit conditions to be simulated
- Assumptions for GDC 5 scenarios include:
  - Loss of Coolant Accident (LOCA) in one unit, second unit progressing to cold shutdown
  - Loss of offsite power
  - Loss of Train A power to both units (single failure)
  - Loss of downstream dam
  - 85° F river water temperature (technical specification limit)
  - Heat exchangers – max fouling
  - ERCW and CCS pumps at minimum performance
- This results in the single B train CCS heat exchanger serving both the accident and non-accident unit using the CCS pump C-S

General Design Criterion 5

- Analysis of this event shows:
  - Accident unit can be cooled safely
  - Non-accident unit can be brought to cold shutdown in 72 hours for GDC 5 compliance
  - Limitation is non-accident unit remains in Hot Standby (safe shutdown state) for 48 hours prior to entering residual heat removal (RHR) cooling
  - Auxiliary feedwater to steam generators
  - Steaming from SG power operated relief valve (PORV) or safeties
  - If non-accident unit is already on RHR in less than 48 hours, it may be necessary to return unit to Hot Standby
  - Allows decay heat to subside prior to adding load to CCS

General Design Criterion 5

- Final Safety Analysis Report (FSAR) has been revised describing compliance
- Staff requests for additional information have been answered
- Open item closed by NRC in SSER 27
- Remaining action
  - Technical specification revision

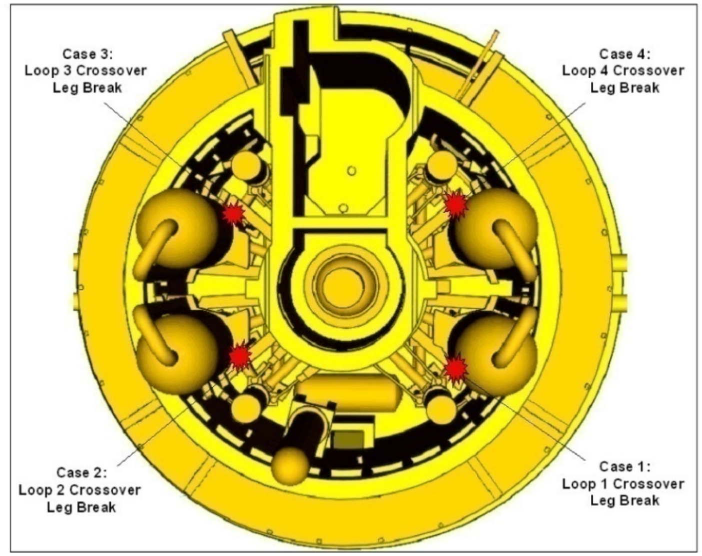
Containment Recirculation Sump

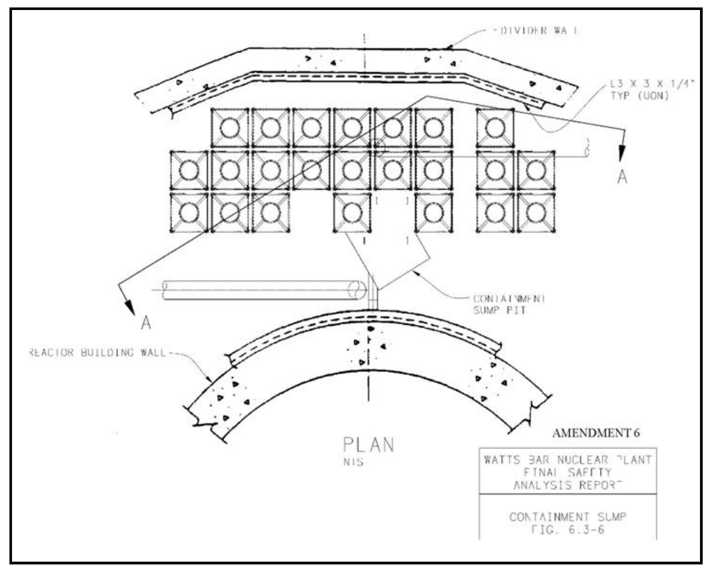
Item 59 – GSI-191
The staff's evaluation of the compatibility of the emergency safety feature system materials with containment sprays and core cooling water in the event of a LOCA is incomplete pending resolution of GSI-191 for Watts Bar Unit 2. (SSER 23, Section 6.1.1.4)

- In 2011, TVA committed that the ECCS and CSS recirculation functions will be in compliance with the regulatory requirements of GL 2004-02 for debris loading conditions at the time of fuel load for Unit 2.

Containment Recirculation Sump

- Strainer design
  - Unit U2 sump design similar to Unit 1
  - Stacked pancake configuration
  - 23 strainer stacks mounted to a plenum feeding the original sump
  - >4600 square feet of surface area
  - 0.085 inch strainer hole size
  - Located under reactor refueling cavity in lower compartment
  - Module flow testing conducted and acceptable





Containment Recirculation Sump

- Unit 2 containment low fiber design
  - Watts Bar uses reflective metallic insulation (RMI)
  - Unit 2 will have no min-K
  - Unit 2 will have no 3M fire wrap
- Debris sources analyzed
  - Unqualified coatings
  - Qualified coatings in the zone of influence
  - Metallic insulation
  - Latent debris
  - Tape, tags and labels

Containment Recirculation Sump

- Analyses include:
  - Debris generation (types and quantities)
  - Debris transport
  - Strainer head loss
  - Chemical effects using Westinghouse methodology (principally aluminum, concrete and fiberglass-surrogate for latent fiber)
  - Downstream effects using Westinghouse methods
  - Orifice erosion evaluated
  - Impacts on pumps, valves, and fuel evaluated
  - LOCA Deposition Model (DM) used to predict impact on fuel temperature

Containment Recirculation Sump

- Status
  - NRC staff confirmed analysis
- Remaining open issues
  - Final accounting of coating mass
  - Final walkdown for latent debris and cleanliness
  - Installation of strainer modules

Questions

ACRS Subcommittee Meeting Regarding

Watts Bar Nuclear Plant Unit 2

Status of Licensing and Inspection

Docket No. 50-391

January 13, 2015

Office of Nuclear Reactor
Regulation (NRR) –
Michele Evans and Justin Poole

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Agenda Topics

- **TVA**
  - Construction Completion Status
  - Discussion of Appendix HH Open Items 59, 61, 63, 91, 93, 133, 134, and Fire Protection Operator Manual Actions
- **NRC**
  - Status of Licensing and Construction Inspection
  - Staff's closure of Appendix HH Open Items 59, 61, 63, 91, 93, 133, 134, and Fire Protection Operator Manual Actions
  - Project Summary

Region II Presentation of Status of Construction Inspection Activities

Region II – Robert Haag

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Construction Inspection Program

- Same program that was used for all existing plants licensed under 10CFR Part 50
- Customized to address the unique history of Unit 2 – IMC 2517 specific to Watts Bar 2
- Historical inspection results factored into scope of current inspection effort
- 553 construction inspection items identified (IP&S database)
- IMC 2513 inspections in additional to IP&S

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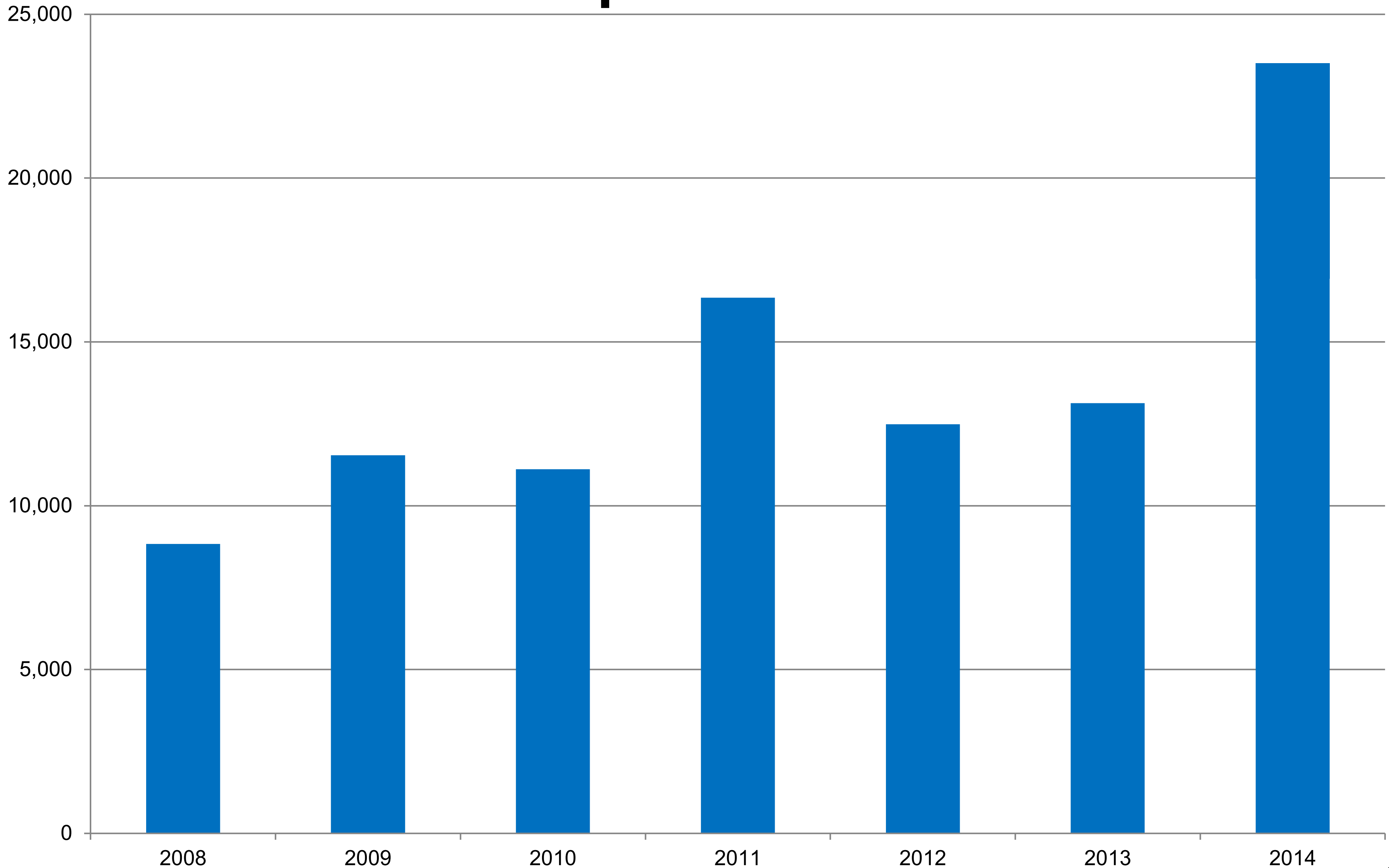
Status of Construction Inspection Activities

- Significant inspection effort in 2014
- Less than 100 IP&S items remain open
- Large majority of remaining IP&S items have been inspected
- Many remaining IP&S items linked to specific TVA activities (ex. ten IP&S items have verifications during Hot Functional Testing)

Substantial Inspection Effort Expended on Watts Bar Unit 2



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Pre-Operational Testing Inspections

- Pre-operational testing inspections closely following TVA’s testing activities
- One of six mandatory tests (RCS hydro) witnessed
- Portions of five of ten primal system tests witnessed
- Challenge: Responding to frequent changes in TVA’s testing schedule

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Operational Preparedness Inspections

- Scope of operational preparedness inspections adjusted based on existing site wide programs and processes being utilized
- Completed 18 of 36 inspection procedures from Appendix B of IMC 2513
- Majority of operations, health physics, quality assurance, and fire protection inspections performed

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Remaining Inspection Activities

- Complete construction (IP&S) inspections
- Pre-operational testing and operational preparedness
- Operational Readiness Assessment Team (ORAT)
- Follow-up to Fukushima Orders (TI-191)
- Fire Protection
- Cyber-security

NRR Presentation of Status of Licensing Activities

NRR – Justin Poole

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Status of Operating License Application

- TVA amendments to FSAR received (A92 to A112)
- Supplements to original Safety Evaluation Report
  - SSER 21 - identifies regulatory framework
  - SSER 22 – FSAR Chapters 2, 3, 5, 6, 8, 9, 10, 13, 14, 17
  - SSER 23 – FSAR Chapters 4, 7
  - SSER 24 – FSAR Chapters 2.4, 11, 12, 13.6.6, 15
  - SSER 25 – FSAR Chapters 15.4
  - SSER 26 – Fire Protection Report Review
  - SSER 27 – Closure of Open Items
- Review Areas Remaining
  - Closure of open items from SER review

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Status of Open Items

- Total Open Items – 128 (some numbers never used)
- Open Items closed as of SSER 27 – 106
- Of the 22 that remain open
  - Items requiring NRC *confirmation* (e.g., updating FSAR): 16
  - Items requiring additional NRC *evaluation* (e.g., additional information required from TVA to complete staff review): 6

Section 2.4.10: Flooding Protection Requirements – Closure of Open Items 133 and 134

NRR – Timothy Lupold

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Open Item 133 – Sand Basket Stability

- Open Item 133 looked to confirm the stability of the sand baskets (HESCO barriers) during a seismic event.
- October 31, 2011 – TVA stated sand baskets are not required to be in place during and following the seismic events in FSAR Section 2.4.4.
- July 19, 2013, - TVA stated the permanent modifications to replace the sand baskets have been chosen.
  - Combination of concrete floodwalls and raised earthen embankments or earthen berms.
  - Committed to have permanent modifications in place by May 31, 2015, except for 1900 feet at the Fort Loudon Dam that will be completed by February 1, 2017. (License Condition)
- Based on description of permanent modifications and the license condition to complete them in a reasonable timeframe, NRC staff considers Open Item 133 to be closed.

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Open Item 134 – Hydrology Review

- LAR submitted to update licensing basis for WBN Unit 1
  - Same information submitted as amendment to WBN Unit 2 FSAR
- Main differences from the current WBN licensing basis
  - Use HEC-RAS river hydraulic model to replace SOCH model
  - Meet FERC dam stability criteria
  - Update probable maximum precipitation (PMP) to produce probable maximum flood (PMF) elevation
  - Re-evaluate dam stability for postulated dam failures under PMF condition
  - Install permanent flood protection barriers

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Open Item 134 – Hydrology Review (cont)

- New PMF 738.9 ft. due to 7,980 square mile storm and postulated dam failures but will have a licensing basis of 739.2 ft. to provide additional margin.

- Wind wave setup and run-up effects were added on the 739.2 ft. for various locations of the site.

Open Item 134 – Hydrology Review (cont)

- Staff reviewed and/or performed confirmatory analysis for the following:
  - Watershed Hydrology, including updated watershed hydrologic and river hydraulic simulations
  - The controlling PMP from 7,980 mi^2 storm
  - HEC-RAS model input, assumptions, setup, and resulting data.
  - Stability analysis of critical dams
  - Impact on flood mode equipment inside of buildings
- Staff conducted a dam stability audit.
- No issues have been identified by the staff during its review and all questions have been resolved.

Fire Protection Operator Manual Actions

NRR – Charles Moulton and
Daniel Frumkin

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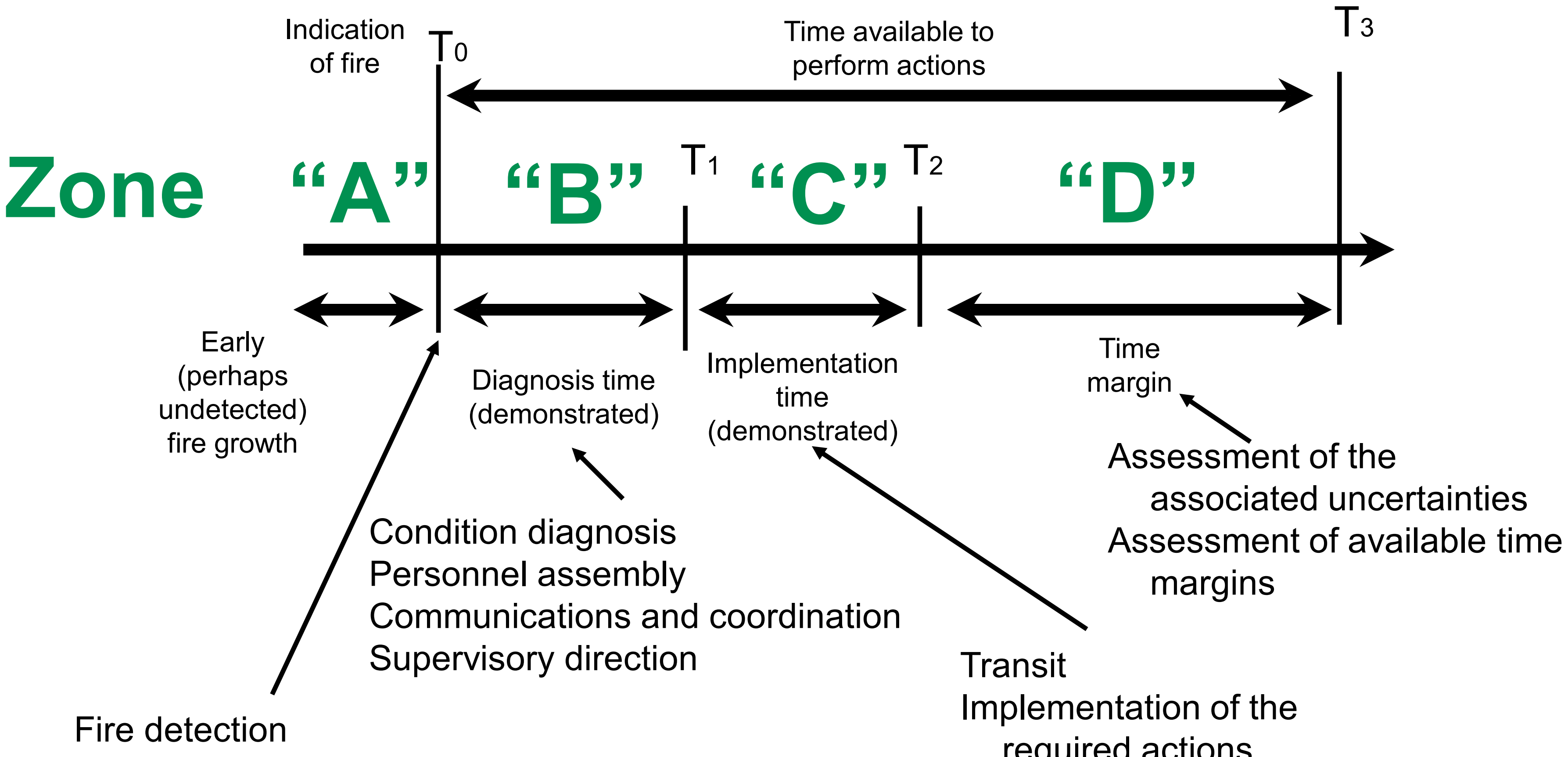
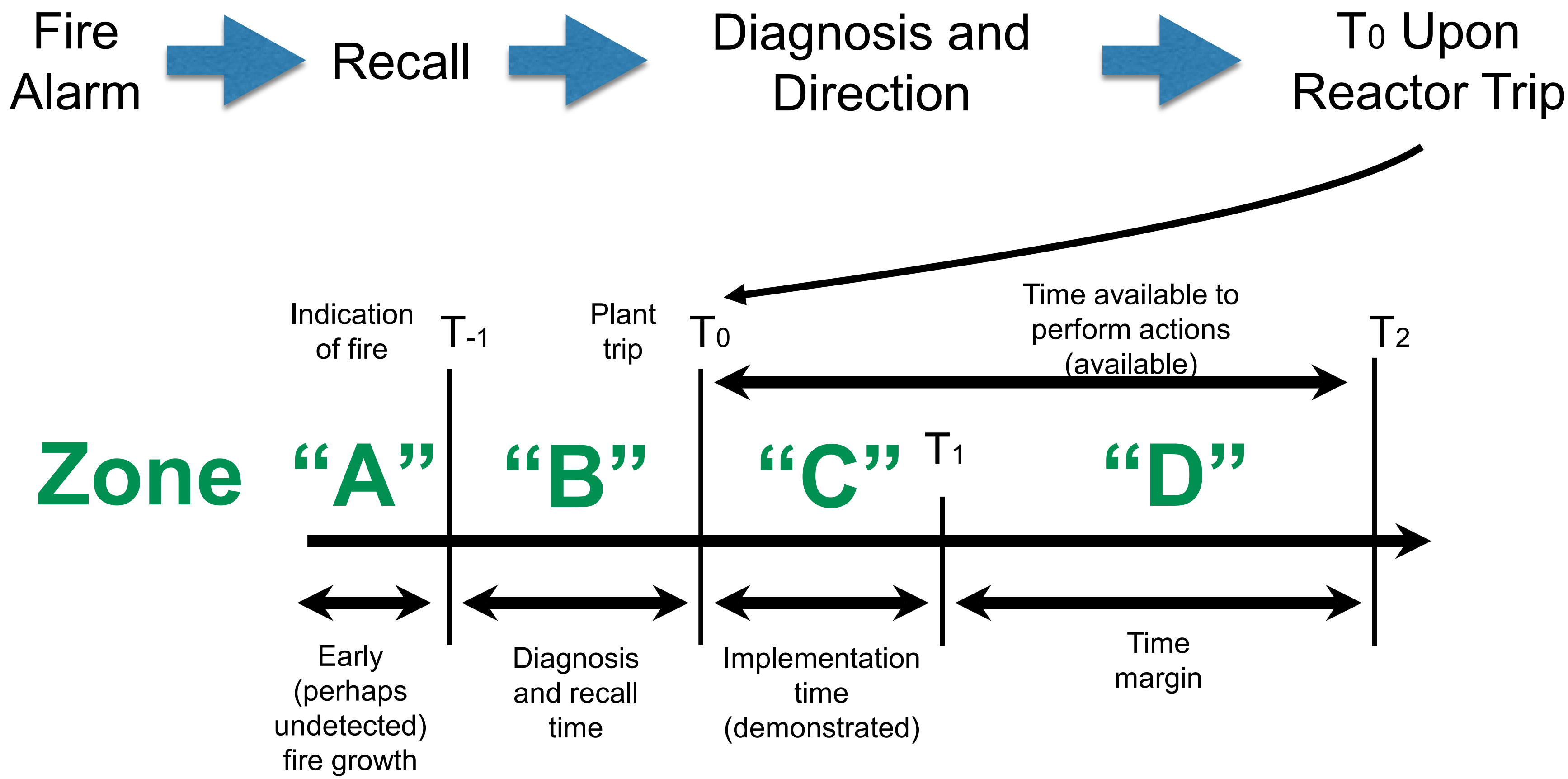
The figure compares ACRS' topics for additional explanation to the NUREG-1852 timeline.

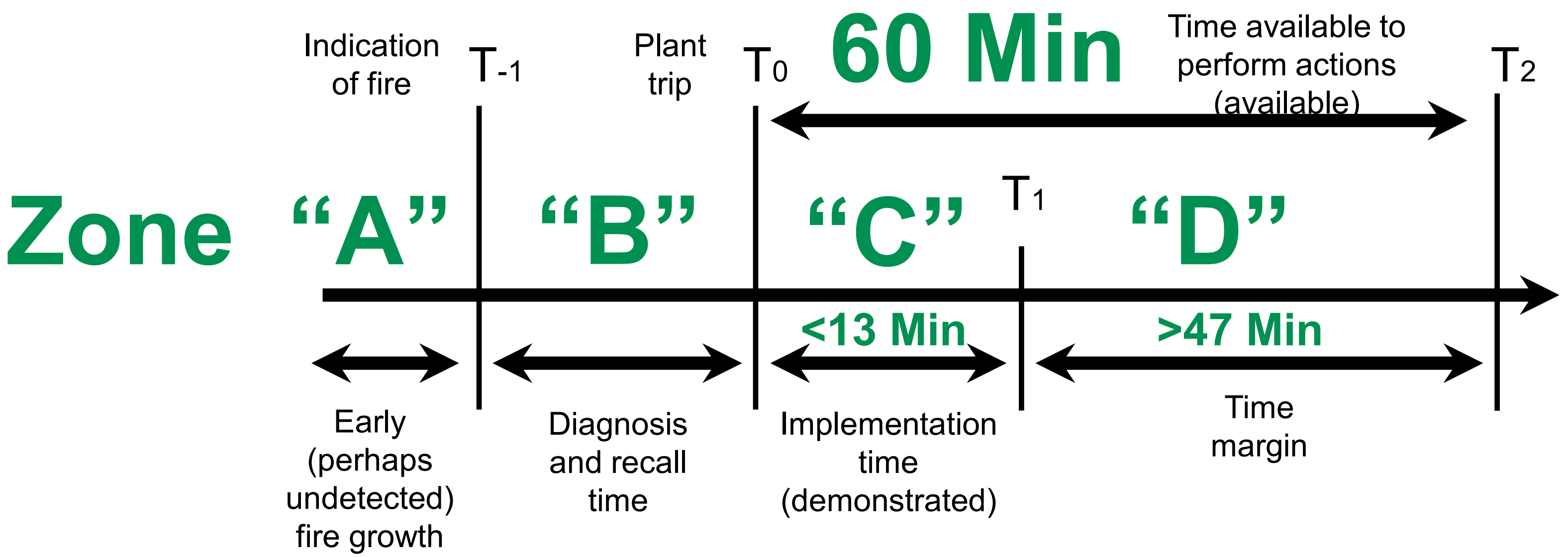


Watts Bar 2's analysis modifies the entry point into the NUREG-1852, to simplify Time=0.



Uncertainties are addressed through time margin. OMAs have >100% margin or the NRC staff has reviewed.

Operator Manual Action (OMA)1016
in Room 757.0-A10



Eagle 21 Communication – Closure of Open Items 63 and 93

NRR – David Rahn

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Open Items 63 and 93 – Eagle 21 Communications

- SSER 23 – Open Items 63 and 93 created to confirm that digital communication into the Eagle 21 RPS/ESFAS from outside the system is prohibited, and two-way communication is not possible.
- NRR staff reviewed test plan, test set-up, summary of test steps, and summary of results
- Region II witnessed testing during an inspection
- Staff found the setup to be appropriate and test results showed two-way communication can not occur.
- Open Items 63 and 93 are closed

Use of PAD4TCD –

Closure of Open Item 61

NRR – Justin Poole

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Open Item 61 – Use of PAD4TCD

- TVA provided new PAD fuel performance data that includes explicit modeling of thermal conductivity degradation (PAD4TCD).
- Previous use of PAD4TCD in EPU review (Turkey Point)
- Staff performed confirmatory analysis which showed good agreement between PAD4TCD and FRAPCON.
- Open Item 61 is closed.
- Proposed license condition limiting the use of PAD4TCD to the initial fuel cycle.

Emergency Raw Cooling Water – Closure of Open Item 91

NRR – Justin Poole

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Open Item 91 – ERCW

- Based on information provided in RAI response, Staff found ERCW to meet GDC 5 in SSER 23. Open Item 91 created to ensure this information was captured in the FSAR.
- TVA updated FSAR in Amendments 102, 105, 107, and 112.
- Staff is satisfied that the wording in the FSAR ensures that the ability to bring the non-accident unit to cold shut down is now included in the system requirements.
- Open Item 91 is closed.

Closure of Open Item 59

NRR – Justin Poole

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Open Item 59

- Statement on coatings added in FSAR regarding compatibility of ESF system materials with containment spray and core cooling water during a LOCA.
- Staff completed its review of WBN 2 response to GL 2004-02 (September 18, 2014)
  - Debris will not inhibit the ECCS or CSS performance of its intended function to assure adequate long term core cooling.
- Section 3.2.8 Coating Evaluation
  - Assumptions made in GL response match the statement added to FSAR.
- Open Item 59 is closed.

Project Summary of Watts Bar Unit 2 Remaining Activities

NRR – Justin Poole

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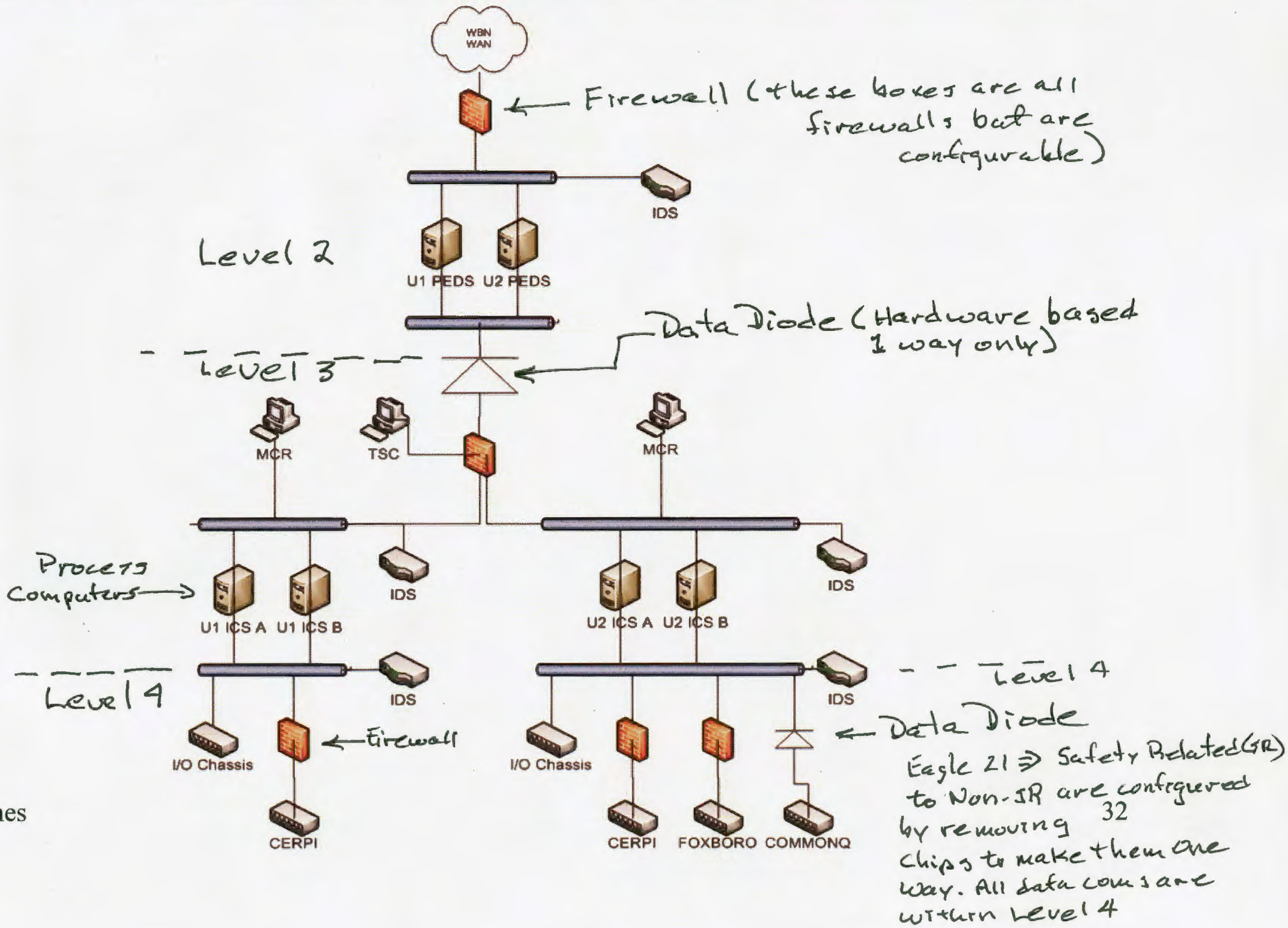
Project Status

- Staff review nearing completion
- Future Milestones
  - ACRS Full Committee
  - Close out remaining Open Items
  - Commission Vote Paper
  - Operational readiness assessment
  - Certification of as-built construction

Process Computer



Hilmes