UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

February 6, 2012

MEMORANDUM TO: Mr. Harold Ray, Chairman
Operations and Fire Protection Subcommittee
Advisory Committee on Reactor Safeguards

FROM: Girija Shukla, Senior Staff Engineer /RA/
Technical Support Branch
Advisory Committee on Reactor Safeguards

SUBJECT: MINUTES OF THE MEETING OF THE SUBCOMMITTEE ON PLANT OPERATIONS AND FIRE PROTECTION ON DECEMBER 15, 2011

A copy of the minutes for the subject meeting is attached for your review. Please review them and provide your comment at your earliest convenience. Please send me your comments and changes for incorporation. If you are satisfied with these minutes, please sign, date, and return the attached certification letter.

Attachments:
1. Certification Letter
2. Meeting Minutes

cc: Subcommittee Members
C. Santos

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

February 11, 2012

MEMORANDUM TO: Girija Shukla, Senior Staff Engineer
Technical Support Branch
Advisory Committee on Reactor Safeguards

FROM: Harold Ray, Chairman
Operations and Fire Protection Subcommittee
Advisory Committee on Reactor Safeguards

SUBJECT: CERTIFICATION OF THE MINUTES OF THE MEETING OF THE SUBCOMMITTEE ON PLANT OPERATIONS AND FIRE PROTECTION ON DECEMBER 15, 2011

I hereby certify, to the best of my knowledge and belief, that the minutes of the subject meeting held on December 15, 2011, are an accurate record of the proceedings for that meeting.

/RA/

Harold Ray, Chairman Date
Plant Operations and Fire Protection Subcommittee

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

February 13, 2012

MEMORANDUM TO: ACRS Members

FROM: Girija Shukla, Senior Staff Engineer
Technical Support Branch
Advisory Committee on Reactor Safeguards

SUBJECT: CERTIFICATION OF THE MINUTES OF THE MEETING OF THE SUBCOMMITTEE ON PLANT OPERATIONS AND FIRE PROTECTION ON DECEMBER 15, 2011

The minutes for the subject meeting were certified on December 15, 2011 as the official record of the proceedings of that meeting. A copy of the certified minutes is attached.

Attachment: As stated

cc w/o Attachment:
E. Hackett
C. Santos

cc w/ Attachment: ACRS Members

Certified: February 11, 2012 **Issued: February 13, 2012**
By: Harold Ray

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
MINUTES OF THE ACRS
PLANT OPERATIONS AND FIRE PROTECTION SUBCOMMITTEE MEETING
DECEMBER 15, 2011

On December 15, 2011, the ACRS Subcommittee on Plant Operations and Fire Protection held a meeting in Room T-2B3, 11545 Rockville Pike, Rockville, Maryland. The meeting was convened at 8:30 AM and adjourned around 3:15 PM the same day. The meeting was open to the public. No written comments or requests for time to make oral statements were received from members of the public related to this meeting.

ATTENDEES:

ACRS Members
Harold Ray (Chairman)
John Stetkar
Charles Brown
Mike Ryan
Dick Skillman
John Sieber
Said Abdel-Khalik

ACRS Staff
Girija Shukla (DFO)

TVA
David Stinson
Robert Bryan
Frank Koontz
Tom Wallace
Steve Hilms
Gordon Arent
Nick Welch

Westinghouse
David Fink
Alan McDonald
Chris Mchuge
Ryan Rossman
Robert Bryan

NRC Staff
Allen Howe, NRR
Robert Haag, Region II
Pat Milano, NRR
Leta Brown, NRR
Samuel Miranda, NRR
John Parillo, NRR
Roger Pedersen, NRR
Justin Pool, NRR
Ed Smith, NRR
Bruce Bavol, NRR
Steve Campbell, NRR
Fred Lyon, NRR
Steve Schaffer, RES
John Lamb, NRR
Geary Mizuno, OGC

SUMMARY OF MEETING

The purpose of the meeting was to review and discuss the status of construction, inspection, and licensing activities related to Watts Bar Nuclear Plant Unit 2 (WBN 2). The meeting transcripts are attached and contain an accurate description of each matter discussed during the meeting. The presentation slides used during the meeting are attached to these transcripts. Following are the significant issues and topics discussed in the meeting.

Significant Issues/Topics Discussed	Link of Pages in Transcript
NRC Staff Overview of Watts Bar 2	Page 6, Line 21
TVA Overview of Watts Bar 2, Reorganizations and safety-conscious work environment	Page 12, Line 18
TVA Discussion of Startup & Testing – Goals, Overview, & Current Status	Page 23, Line 12
TVA Discussion of Transition to Operations	Page 27, Line 2
TVA Discussion of SSER (22-25) Open Items	Page 36, Line 20
TVA Discussion of Radiation Protection	Page 37, Line 24
TVA Discussion of Meteorology	Page 52, Line 2
TVA Discussion of Radiological Consequences of Accidents	Page 64, Line 7
TVA Discussion of FSAR Chapter 15 Transient Analysis	Page 68, Line 24
NRC Staff Discussion of Chapter 15 Transient and Accident Analyses	Page 86, Line 25
Region II Presentation of Status of Construction Inspection Activities	Page 128, Line 13

NRC Staff Status of Licensing Activities	Page 158, Line 17
NRC Staff Discussion of Open Items	Page 160, Line 12
NRC Staff Discussion of Supplements 24 and 25 to SER	Page 164, Line 11
NRC Staff Status of Radiation Protection reviews	Page 164, Line 13
NRC Staff Discussion of Design Basis Accident Dose Consequence Evaluations	Page 186, Line 16
NRC Staff Project Summary of Watts Bar Unit 2 Remaining Activities	Page 195, Line 24

ACTION ITEMS	
Action Item	**Link of Pages in Transcript**
Need CVCS analysis in Modes 3, 4, 5, and 6	Page 73, Line 3
Discuss CVCS malfunction in Modes 3, 4, 5, and 6	Page 79, Line 20 Page 92, Line 10
Cyber Security needs to be discussed more	Page 149, Line 14
Discuss communication between Eagle 21 and the main computer	Page 154, Line 13
Discuss Confirmatory Items No. 63 and 93	Page 156, Line 4
Open Items of interest – 59, 61, 65, 91, 93, 132, 133, and 134	Page 198, Line 14

DOCUMENTS PROVIDED TO THE SUBCOMMITTEE:

- NUREG-0847, Supplement 25, Safety Evaluation Report Related to the Operation of Watts Bar Nuclear Plant, Unit 2, dated December, 2011
- Watts Bar Unit 2 Final Safety Analysis Report (FSAR) Amendments No. 105 & 106

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards
Plant Operations and Fire Protection

Docket Number: (n/a)

Location: Rockville, Maryland

Date: Thursday, December 15, 2011

Work Order No.: NRC-1340 Pages 1-210

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

+ + + + +

PLANT OPERATIONS AND FIRE PROTECTION SUBCOMMITTEE

+ + + + +

THURSDAY

DECEMBER 15, 2011

+ + + + +

ROCKVILLE, MARYLAND

+ + + + +

The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., Harold B. Ray, Chairman, presiding.

MEMBERS PRESENT:

HAROLD B. RAY, Chairman

SAID ABDEL-KHALIK, Member

CHARLES H. BROWN, JR., Member

MICHAEL T. RYAN, Member

JOHN D. SIEBER, Member

GORDON R. SKILLMAN, Member

JOHN W. STETKAR, Member-at-Large

NRC STAFF PRESENT:

GIRIJA S. SHUKLA, Designated Federal Official

LETA BROWN, NRR/DRA/AADB

ROBERT HAAG, Region II

PAT MILANO, NRR

SAMUEL MIRANDA, NRR/DSS/SRXB

JOHN PARILLO, NRR/DRA

ROGER PEDERSEN, NRR/DRA

JUSTIN POOLE, NRR/DORL

ED SMITH, NRR

ALSO PRESENT:

GORDON ARENT, TVA

ROBERT BRYAN, TVA

STEVE HILMES, TVA

FRANK KOONTZ, TVA

ALAN MACDONALD, Westinghouse

CHRIS McHUGH, Westinghouse

RYAN ROSSMAN, Westinghouse

DAVID STINSON, TVA

TOM WALLACE, TVA

A G E N D A

P R O C E E D I N G S

8:31 a.m.

CHAIR 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 Said Abdel-Khalik, Gordon Skillman, John Stetkar, Charles Brown, Jack Sieber and Michael Ryan. Mr. Girija Sukha of the ACRS staff is the Designated Federal Official for this meeting.

This meeting will be open to public attendance. A telephone bridge line has also been established for this meeting to preclude interruption of the meeting. The phone will be placed in listen-in mode during presentations and committee discussions. The subcommittee 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 Nuclear Plant Unit 2.

We've received no written comments or requests for time to make oral statements from members of the public regarding today's meeting. There is time on the agenda for public comments at the end of

the day.

The subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions as appropriate for deliberation by the full committee. The rules for participation in today's meeting have been announced as part of the notice of this meeting published in the Federal Register on November 18th, 2011. A transcript of the meeting is being kept and will be made available as stated in the Federal Register notice. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee. The participants should first identify themselves and speak with sufficient clarity and volume so that they may be readily heard.

Please silence your cell phones as the chairman is now doing with his. We will now proceed with the meeting and I will call NRC staff to make introductory remarks. Mr. Pat Milano.

MR. MILANO: Good morning, Mr. Ray and members of the subcommittee. We're here today as Mr. Ray indicated to continue with our discussions on the operating license application submitted by Tennessee Valley Authority for ultimate operation of Watts Bar

Unit 2. With me today and the individuals who will be speaking, to my left Justin Poole who's also with the Watts Bar Special Projects Branch, another one of the licensing project managers, and from the staff in Region II Mr. Bob Haag who is branch chief with the Division of Construction Projects and he'll be discussing the inspection status. There will be also members from the NRR technical staff who conducted, who were the primary leads for conducting the areas of review that we will be discussing today.

Before I actually get into the actual topics of discussion just so that you understand a little bit of change to the organization within the Watts Bar Special Projects Branch. Our branch handles both Watts Bar Unit 2 and TVA's Bellefonte 1 and 2, the Bellefonte 1 project in particular. So because of that and a shifting of our work assignments Mr. Poole is, Justin is going to be doing more of the lead review for Watts Bar, or coordination for Watts Bar. So, today he'll be doing the majority of the coordination for the NRC staff and in the future will be handling everything himself.

For today the agenda, we're going to be talking, TVA's going to be talking first. I'll be introducing them shortly. They're going to give you

a short discussion of the construction completion status that currently exists and then we're going to go into the areas of the FSAR review that we're here for today. Noting that some of these areas cover multiple supplements to the Safety Evaluation Report because of the fact that we postponed discussions and in particular with the accident transient analysis in Chapter 15, we did that awhile back. We were going to do that in one of the earlier meetings.

So today we're going to discuss Chapters 11 and 12. Basically that entails the liquid and gaseous release and operational dose consequences. Then we're going to go into Chapter 15.4 discussing the accident dose consequences. And it seems like, a little bit out of sequence but this aligns with the way TVA is going to make their presentation. Then they're going to talk to the actual accident transient analysis that's in Chapter 15.

Also, when the NRC comes up late this morning and then this afternoon we're going to, Mr. Haag will give you the status of the construction inspection and then we're going to go into a short status on open items. As you're aware, in Supplement 25 currently there are 83 items that remain in an open condition. Forty of those items are open and will

require some amount of staff evaluation once either, once TVA provides something or we obtain something from the region.

There are a couple items that are inspectional in nature like environmental qualification, inspection and audit. Of the other 43 items out of that 83 are what the staff calls confirmatory items and those items, the areas that those items exist in have to do with stuff where the staff has already made its reasonable assurance determination but that was based on something, based on the staff's understanding. And what those will be is as long as our inspection program or TVA provides us documentation which confirms the fact, the basis for our conclusion then there will be no other staff evaluation that needs to take place. We'll just document the fact that TVA confirmed something or the region confirmed by inspection that item. So in reality out of those 83 only 40 of them really will require some amount of staff evaluation and we'll be discussing those in future subcommittee meetings. And then lastly we'll discuss the few items that remain for staff review and presentation in the April subcommittee meeting.

CHAIR RAY: On the open items I think you

gave a good summary and certainly we all understand that confirmatory items are open because of the reasons that you said. In going through the 40 I'm sure there are some that you won't want to have to come back and talk to us about but there are some that we will.

MR. MILANO: Yes.

CHAIR RAY: And if we have time, let's see how time goes today but we may want to be more clear about which those are so that people aren't surprised or disappointed respectively on the subject.

And then I did want to say as I mentioned to you before the meeting, I guess I thought we were going to have more discussion of the complex relationship between Unit 2 and Unit 1 when it comes to flooding hazard and that assessment and the time lines associated with it and so on. There's a license condition proposed that deals with that, but I think we still need to understand it better than we did last time. I thought we were going to do that this time. It's not urgent but we do need to understand it because the full committee may wish to express an opinion about it.

MR. MILANO: Right. You are indeed correct, the staff's plans are to address that. There

are some actions that are continuing to go on in basically two areas. One is we -- this issue is not Unit 2-specific, it's site-specific. The same probable maximum flood level affects both units equally. The compensatory actions that are taken are for both units and so right now what the staff is doing, it's going to -- we believe it's going to take a licensing basis change and a license amendment for Watts Bar Unit 1. That is, the staff is working with TVA to get that submitted and evaluated, and also the staff is looking at doing some further evaluation of the results that were submitted in -- as an amendment to the Unit 2 FSAR that provided the new probable maximum flood level. We're going to be doing some amount of confirmatory analysis that's not yet completed and we'll present that also to you along with the discussion.

We were hoping to do that in April. However, based on all these activities it's doubtful that TVA and the staff can get completed by April. So those will be one of the follow-on discussions that we'll have at a later time.

CHAIR RAY: Well all right, but I still want to point out that this may not be as simple as oh well, we'll adopt what we did for Unit 1. It's

possible that there's some comment that would be forthcoming as to Unit 2 on its own and so the sooner the better so that that can be discussed. Thank you.

MEMBER STETKAR: Just out of curiosity, that all has to be integrated with Bellefonte also, right?

MR. MILANO: Bellefonte, what TVA had done is as you're probably aware when TVA reassessed the complete Tennessee Valley watershed area and stuff, and it came up during the Bellefonte 3 and 4 review and you're correct, it will affect Bellefonte, there's some actions that TVA is contemplating completing for Bellefonte 1 and 2 to change the site characteristics over there. So you're correct, it affects all of their stations.

MEMBER STETKAR: Okay, thanks.

MR. MILANO: With that I'm going to turn it over to TVA to begin their discussions. And Mr. David Stinson, the vice president for Watts Bar Unit 2 and his staff will be making the presentation.

MR. STINSON: Good morning.

CHAIR RAY: Good morning.

MR. STINSON: It's a pleasure to talk with you today. What we're going to do is I'm going to give you a fairly quick update on Watts Bar status.

We've had some changes since the last time we met that you may be interested in. Bob Ryan to my right will talk about meteorology and radiation protection along with radiological consequences of accidents, and Frank Koontz will talk about transient analysis. Then we'll open it up for questions.

As far as status goes let me just talk about four primary subjects to kind of give you an overview of the project. One is how we're doing with safety, quality, our safety-conscious work environment program, and then some reorganizations that we've done and new alignments on the project, and then Gordon will talk about Appendix HH status.

So last week we surpassed 13 million man-hours without a lost work day. That's a major milestone for us. TVA's record there is 14.3 so we still have a little ways to go. If we can keep ourselves focused on safety through the next three months we'll actually have two years without a lost work day so we're very proud of that. It's a good accomplishment for the project.

Last year we worked almost 7.5 million man-hours. We had a recordable injury rate of 0.49. On projects like what we are doing this job today we look for companies that have an RIR around 1 to 1.5 as

being a good record, so 0.49 is an exceptional safety record. Our contractors in the OTV team have done a good job here.

There are over 28,000 supervisors' safety interventions. This is something that we've done contractually. We try to get more people involved. We know that about 83 percent of all injuries occur when the foreman's not in the area, some level of supervision, so we try to get as many folks out in the plant as we can. Also, our craft engaged in this. I know the program card, the intervention, the card program when they find someone that's not wearing the correct protective equipment or doing something in the wrong manner, they write those things up and submit them and we get better because of it. So we're proud of our safety program, we continue to focus on that and keeping people safe to come back to work the next day.

Organizational structure. We had a contract with the Bechtel Power Corporation that was based on an engineering procurement construction contract. We've reached a time in the project where TVA needs to take more responsibility so we've actually converted that to more of a managed task contract, and the roles you'd expect for Bechtel are

being --

CHAIR RAY: Excuse me, Dave. Say that last sentence again, please? You converted it to?

MR. STINSON: To more of a managed task approach or a contract as opposed to in an EPC basically we give them the keys to the plant, they do the work and in the end they give the keys back. We're a little different in that TVA does have the startup responsibilities for the plant, we have an operating unit next door and the degree of interaction that we need to have daily is a little smoother when there's TVA people working directly with TVA people. So we modified the contract slightly. TVA, Bechtel has responsibility for engineering, for quality assurance, for supply chain and for ASME construction and other type construction work that we assign to them. What's changed really is TVA has taken on a different role in that whereas before work priority came under the EPC, TVA takes responsibility for work priority. We assign day-to-day direction. I think more importantly we're responsible singlehandedly for schedule and work performance. So this is, like I said, a natural evolution on the project.

We've staffed to fill these responsibilities on the TVA side. We have a few

vacancies that we still need to fill, and I think what's important for us is that this is the model that we'll actually start Bellefonte out as and finish as. It's TVA taking that leadership role day to day. So it clearly defines responsibility and it lines up our management model with our contract model so there are no conflicts between the two.

Organization is, I know you can't read this slide that easily, but what's important is that we've got bold blocks in there and then the non-bolded blocks. The bold blocks are the Bechtel organization. Because of the end stamp and their requirement to maintain technical direction we place them in the center of the organization and wrappered the TVA organization and other contractor organizations around that group. And like I said, it cleans up lines of responsibility and it changes behavior in a way that I think is very positive for us in that if we have issues on the project they're not a company problem, they're a project issue that we need to resolve. We've actually gone to one color hard hat for all our Unit 2 people to kind of further, you know, build that team environment on the project. And we've seen some success with that. Let's go to the next slide.

Quality. I just want to point out the

quality program has not changed. TVA still maintains the oversight role in that area. What has changed is that we modified our contract so that more companies can work under that quality, under Bechtel's quality program, gives us the ability to put different skill sets on the job and be more efficient. So no major changes there other than the fact that other companies are also working under Bechtel's quality assurance program.

Safety-conscious work environment is an important program for us. It's one of the cornerstones of our nuclear quality program. I think we understand the foundation of any SCWE-type program, communication. We spent a lot of time, I just finished 24 all-hands meetings to get all 2,800 folks through that process talking about the changes to the organization that we've had, our safety program, quality program, that sort of thing. So we try to talk a lot. We also try to listen more effectively. As managers we tend to be very focused on -- not necessarily listening, so we're working on that program.

We have a lot of different monitoring tools that we use to pulse the site, to make sure that we don't have issues that are ongoing that we're not

aware of. And like most utilities we have a lot of different ways for people to get safety issues on the table as you're aware. The supervisor is a principal path for identifying safety issues and getting those raised and resolved. And then we also have our Corrective Action Program, it's anonymous, and a kind of sign-your-name type program. Our employee concerns program, both the companies that we're working with and TVA. Interesting to note that people tend to be more comfortable coming to TVA's ECP, so about 92 percent of the people feel more comfortable working with that. We have both avenues available. We also have our inspector general who's actually onsite and either walk into any of their office or they can also use the empower line, phone line that works very effectively. I tell the folks that if they have an issue that they don't feel comfortable coming to their supervisor they can use that. Every morning at 6:30 I get the previous day's comments that may have come in and I get 15 days to respond so it's a good program there. And then finally, you know, the NRC and walking through the door there or hitting the hotline as well. This was an area that we were concerned with. Let's go to the next slide.

MEMBER SKILLMAN: Before you go, let me

ask this. I'm Dick Skillman. What events triggered your taking back the keys and your focus on presentations on SCWE? You just said you had 24 meetings to meet 2,800 people.

MR. STINSON: Right.

MEMBER SKILLMAN: That is a huge focus for you and your staff. Taking the keys back from Bechtel Williams was also a very large step. What triggered that?

MR. STINSON: Well, it was really was the conflict between the way that the project needed to be managed and the level of involvement that TVA needed to exercise on the program and the integration between all the different organizations. So the Williams part, Williams is actually relatively new. We took the indirect work, scaffolding laborers, because we have local contractors now working on the project more than just Bechtel, that was the original intent, so we have Day & Zimmerman, we have Williams working a couple of different scopes. We wanted to have like a single integrated support organization that supported all the contractors that TVA would integrate to make sure that everyone got supported equally. We found when we did that we actually had an overlap of responsibility, around 129 people. So we saw some

efficiencies that could be gained by reorganizing our contract models and then also the site. And then, and I would say it was time that we're in the stage where we're starting to start up systems in the plant, hand over major areas of the plant and so we needed to exercise more responsibility and our contract really didn't allow that easily. It was, we had to be given that authority under the contract. We just renegotiated the contract so it was clear that TVA had the lead role and that we would take responsibility for those actions.

MEMBER SKILLMAN: How about the SCWE part?

MR. STINSON: Kind of two reasons. One is it's a requirement. We have a confirmatory order that says that we'll do a certain number of meetings a year and engage the site population on the importance of the program. So there's a mandatory requirement. But also, and if we go to that next slide I'll show you, last year when I, I've been here about 9 years but when I first came onsite I asked how we were doing with NRC allegations and we had 26. And so in my view when you have a number like that, and the project that I came off of, the MOX project in Macon, South Carolina, another NRC reviewed site. And you know, we had around three in the four years that I was in the

same role there. So I saw that number as being very, very high and in my mind it really boils down to a trust issue. Do you feel like as an employee that you can raise safety concerns and that people will listen and they'll do something about it.

And so we have, you know, I talked about the past employee concerns resolutions, we have those five paths, four of those are internal to either the companies that work with us or TVA, and in fact both have those same paths. Usually if you're comfortable with the environment that you will use one of those four paths. And not always, but usually. So to me it looks like potential for a trust issue with the management team. And so I felt that it was important to continue focusing on these areas so that we could let people know, you know, our approach.

And it's really simple like trying to focus like with managers what their responsibilities are. We talked in terms of how we set work hours. I can tell you my work hours are set. I come in before the project starts and I leave you know well after the project is over for that shift, and the idea being that we ought to make sure that people know they can come in and talk and raise safety concerns or any issue that they might have, that that's my

responsibility that if no one else will listen to you I will. That was the message. Managers have that responsibility as well. So when you go from a situation where you have a lot of things that are going outside the internal paths to get resolution, that you've got to do things that are different. And so we're trying to take a different approach to folks and personalize the concerns process, trying to really emphasize to people you know like me. I grew up within five miles of the Valley, my family still lives you know right next to Browns Ferry. This is personal. You know, we need to make sure that we do a good job. We're all interested in this being a safe plant and that if no one else will listen to you that I will, and that's kind of the example that we're trying to set through these meetings.

MEMBER SKILLMAN: Thank you.

MR. STINSON: And you know, how are we doing, we're doing better. I wouldn't say we're good yet. We've, through September we've had four allegations, a couple earlier in the year and then one each in August and September. We have had an upturn in allegations. We, through this reorganization and through our new budget that we established for 2011 we had a layoff. About 750 people were affected by that

layoff. We got 3 to 4 allegations in October and I think we had 2 in November so we're up in the 10 to 11 range for the year. Better, still not where we need to be. And so there was a belief that we needed to continue to reinforce that message of openness on the project. So we're doing better, not quite where we need to be. I'd like to see that at zero or one, you know, kind of number. Let's go to the next slide.

I wanted to just follow up with some pictures of the plant as we finish out the area. A lot of focus right now in two areas. One's the turbine building. We're trying to get out of that by springtime so we're really focusing on just completing the startup of the secondary side of the plant, and also upper containment. We're in the process of painting out upper containment right now. That's lube oil system, the different panels that are there.

One of the things that this plant is a little unique in that we've had an operations and maintenance staff that have worked on a single unit inside a 2-unit plant for the last 16 years, and had been able to do pretty much what they wanted to do at the plant because it was all theirs. Now we're talking about bringing in a second unit and we want to make sure that it is very, very clear that they're on

Unit 2 and so we do that with color. So Unit 2 is the blue unit on the site. If you walk up to a panel the floor is actually will all be blue here in the near future. You know that you're on Unit 2. If you walk up to an MCC panel and the bucket is blue it's Unit 2; if it's white, it's common systems; if it's red it's fire protection; if it's any other color it's Unit 1. So we've been very directive on how we were going to paint out the plant to make it easier for people to understand the difference between the two units visually and then all the other cues are there as well, but just to minimize mistakes because of the many years that we've been running as a single unit. Let's go to the next slide.

Turbine deck itself. Like I said this is something that for us is a point of pride. You know, we have millions of man hours that go into this plant and when we finish all people really see are the paint and insulation, and so it needs to reflect the pride and the skills that we put into our work. So we're focusing very heavily in this area so we'll present the plant with a unit that they'll be very proud to own and to operate. Let's go to the next slide.

Talk quickly about our startup program on this slide. There's really nothing new. We have, you

know, a standard startup program, meeting all the Chapter 14 requirements. We're going through a component test and system test at this time. We've used a focus on the turbine building site so that we could get all of our safety-related system procedures and skills that are needed tested on the non-safety side so that we would minimize any errors that might occur on the safety-related side. And that testing is going well. Next slide.

So we're currently about 23 percent complete with component testing. We're doing system flushing. Right now we're flushing out the feedwater lines on the secondary side. Pre-operational testing, it's the 1.68 and FSAR guidance, we've got 43 out of 119 procedures that are approved and we're about 71 percent complete with overall procedure generation. We have 20 additional in our JTG. All the testing and flushing that's done is under NGDC as opposed to the operational group NPG. We've turned over 38 of 86 systems to startup. We turned over four systems to the operations organization. We have two more scheduled by the end of the year.

So where are we at? So we have our tanks are filled with pump suctions, refueling water storage tank, RWST, and the primary water storage tank. We

have condensate in operation, feedwater in service with two of the hotwell pumps running on 3 mrem. Booster pumps are running. We have tested through two of the three and the third one should be tested this week. The condenser circulating water is in service so the cooling towers are in operation. Raw cooling water is in service. The oil systems are put in place. We're turning over the turning gear, putting our turbine on turning gear weekly. Annunciator computer systems are in service. We're calibrating our solid state protection systems. The main feedwater pump oil systems are in service and the pumps are where we're flowing water through the feedwater system for flushing. And control air flushing is in progress.

I will tell you that we felt like the plant was in a good cleanliness level overall but we've been very surprised with how well the plant's cleaned up. We're very finding very little material in the strainers and we're going to come down in January and take condensate out of service. We'll go into the hotwell and we expect to find, you know, debris there but as you would normally. So we'll go and muck that out, clean that out and then we'll have a very clean, tight system in order to operate the

plant. Next slide.

So transitioning operations. The operations group are engaging regularly, you know, with us. We have a Unit 1-Unit 2 interface team, that 32 individuals that are part of the plant staff that work with us to make sure that the plant is ready to accept the systems and that the systems are in the right stage of completion for them to own. Our chief nuclear officer meets with us every other month in what we call a management review meeting. We've gone through and I think we've briefed on where we are with permanent staffing but we have a major turning program and new license classes for both licensed and non-licensed operators and maintenance craft. And one of the things that we're doing over this next year because our schedule is extending into next year is that we're actually using the Unit 2 maintenance staff as part of our startup organization and so we have 19 I&C techs that are in today working. By the end of February we expect to have about 30 mechanical maintenance people that are out of the class, 20 electrical and 20 more I&C techs, so about, I think the number is going to be around 79 maintenance people will be there. So the advantage is normally we would do startup with a contract staff but we'll actually do

it with our own maintenance people so they'll get the opportunity to learn the plant as it comes up, how they operate. Even though the plants are identical, you know, the pumps sound different, you know, than the other so it gives them a chance to really learn the plants. We think, you know, that's going to be very positive.

Training is continuing on dual unit licenses and unit differences and we try very hard to minimize those differences. As we go through the next refueling outage in September for Unit 1 those differences become less and less as Unit 1 comes up to some of our modifications. And under the work management program, you know, we're fully flushing out the process to get to a 26-week schedule basis prior to going into our surveillances for fuel load for the plant.

MEMBER STETKAR: You mentioned you're going to license the operators dual unit.

MR. STINSON: Right.

MEMBER STETKAR: Are you going to have a fully shared maintenance staff also or are they, are they unitized?

MR. STINSON: The maintenance staff is not unitized.

MEMBER SKILLMAN: In your preparations to head towards operations, what operating experience have you incorporated?

MR. STINSON: So, and I'm going to speak to the operations folks and Tom Wallace is our operations manager on Unit 2 that's doing a lot of that work for us. But there's been a lot of concern within TVA and the operational group that this has been a single unit for a long time. Now, we have a sister unit, Sequoyah, down the road. One of the things that they've stressed with operations and maintenance people is that they start taking care visits and going up to the Duke plants, going up to D.C. Cook, similar type plants, looking at their operation, but also looking at other utilities. So they've worked with INPO to set up these peer meetings and so that is one way that they're doing it. And then I think the other way is we, actually today we've got an SRO that's sitting in the horseshoe on Unit 2 and so we had a license class, made folks available. We have five AUOs that are on shift that are permanent AUOs for the plant and so they're coming into the testing process. You know, they're turning switches, operating equipment, they're doing rounds. We're working very hard to establish our standards, you

know, for performance and cleanliness in the plant and working with them to make sure that our standards, you know, are equal to or better than the standards on the operating plant.

So it's really that whole process, peer visits, bringing both operations and maintenance personnel onto Unit 2 in the startup phase of the operation where they start taking ownership of a plant. To me that's the biggest barrier is when is it yours. At what point in time do you take ownership. And so our intent was to bring that date in as early as possible, start making the opportunities available for the operating site to start owning that unit.

MEMBER SKILLMAN: Thank you.

MR. STINSON: Next slide. So transitioning operations. We have a procedure called TI-437 which is how the operations staff goes through the turnover documents and accepts the system. And fairly involved as you would expect. It goes through all the documents that go with that system, drawings, calculations, procedures, maintenance instructions, that sort of thing. And wrapped around some very intensive lockdown to make sure that the plant is exactly in the mode that operations staff expects.

To this point we've turned over four

systems. The first system we turned over was building heat, obviously a very small system, about five breakers involved in that, but it was a little rough. And we're thinking gee, five breakers, that's, you know, shouldn't have been a little rough but it was because you know, there's always that kind of conflict that you'll see between the organizations. What are you giving me, you know, how clean is that system. Are you giving me work to do after I accept it. And so part of this is that trust thing within organizations as well. And so that was a little rough. We did system 37 gland seal water and that was a system that does have ties into the operating unit directly on the secondary side. That was another level of complexity. As we went through we stopped at the end of each process and said okay, what worked, what didn't and we continued to revise these procedures.

Last week we turned over two more systems. These are heating and ventilation type systems, again, 30 Oscar November. We have two more systems that we're looking at this week and will actually go through plant health next week with the outside chance we might be able to do four. We've got a couple of electrical systems that will go over once the RCP

board, and so we're continuing this process. So we're still on primarily non-safety systems. We're working through the processes to make sure that the system, the process that we use is smooth and then we'll finish the safety systems. We'll be more effective that way. Gordon?

MR. ARENT: Yes, this is Gordon Arent from TVA. I just wanted to --

CHAIR RAY: Just a second. You're done, David, are you?

MR. STINSON: Yes, sir.

CHAIR RAY: Earlier in our review, I can't remember which meeting it was now for sure, but it was maybe the first or second meeting, the relationship between the Unit 2 schedule and the Unit 1 operating schedule, outage schedule and so on was of some concern because it was, Unit 2 appeared to be driven to a very tight schedule by the Unit 1 operating availability. Nothing is discussed here although I recall that subsequently there was some change made to relieve some of that pressure that existed. This is perhaps before you had the engagement, I'm not sure, but in any event I guess I'd like to ask you to comment on to what extent Unit 2 is being driven by Unit 1 outage and other status schedule requirements.

MR. STINSON: Okay. I may get some help with this from the folks around the room. I would tell you that there was a lot of pressure at the last outage trying to get the RCW completed during the outage because of the potential for needing a mid-cycle outage if you didn't get it during that outage. We were able to do that work but I think we learned a lot, you know, from that. And I would tell you today the interaction with the site you know goes through a process that does it slow us down from time to time? It does. We may want to get out of the system. You know, we're working around train weeks, you know. We're pretty closely tied into those units, especially around the electrical board so we, you know, we have to work around the train systems. The outage work, for now, you know, if -- we have the next outage for the unit is in September. We view that as an opportunity to do some work in an easier, that's the simplest word I can --

CHAIR RAY: Well, the issue at hand was whether or not Unit 2 was being driven beyond the headlights because of the need to meet those outage windows in Unit 1.

MR. STINSON: I don't see that today. I don't know, Frank, if you want to, or Tom, do you want

to comment?

MR. KOONTZ: Steve may be able to -- I think the issue at the time when we were up here earlier was the blackout testing on the diesels.

CHAIR RAY: Well, there was some but then there was this change --

MR. KOONTZ: I think we resolved that.

CHAIR RAY: -- that occurred.

MR. KOONTZ: How to do that without an outage.

CHAIR RAY: Maybe some overview of the schedule is yet to come and we'll understand that. We're not as concerned I don't believe with the turnover status, that's your business, but with whether or not you're having to do things on Unit 2 prematurely or under too much pressure or whatever because of the outage windows on Unit 1 that are available to you.

MR. STINSON: No sir, I don't see that today. I don't feel that pressure. Tom?

MR. WALLACE: No, sir. I don't think we have that pressure. We worked through earlier issues with our blackout testing and our need for tech spec changes that are ongoing in the process. We did put our hot pipe basically on our essential raw cooling

water system to be able to get our flow numbers that we needed to be able to determine if we could do flow balancing online or we'd have to do it in an outage. We were able to complete that in the outage and have the numbers we need right now to make that decision and not have an impact on the operating units.

CHAIR RAY: All right, well, that's fine then. Take your time. We're not in any -- we're not trying to push the schedule.

(Laughter)

CHAIR RAY: We want to make sure that if there is an interaction between the two that it's not leading you to do something on Unit 2 that you would, that's sub-optimal.

MR. STINSON: The one point I probably didn't mention and I should is that it's obvious we're not on our original schedule, that we're not going to finish in April of next year. And we're in the process now of doing a complete estimate-to-complete on the unit. This one is slightly different in that TVA actually has taken ownership of the schedule and the databases that drive it. We're running samples to make sure that the numbers are accurate. Once we have those estimates complete we'll go through actually a seven kind of level governance review till we get to

our board in February and at that point in time we will announce what our budget to complete will be, what our schedule to complete will be and we'll be able to share that, you know, with you. It's somewhat frustrating I know for staff, you know, wanting to know and set their inspection times around our schedule but because of Sarbanes-Oxley we can't release that. But it's clear that we have a little more time, it's given us a little more planning time to work around these critical issues.

CHAIR RAY: I think you're speaking to the thing that was of concern to us, it just didn't seem to me I could see how you were going to make what was being laid out. We'll see what you're going to come up with after you're ready -- when you're ready.

MR. STINSON: Yes, sir.

CHAIR RAY: Okay.

MR. ARENT: Briefly, I just wanted to talk about the open items. Pat mentioned that at the outset meeting. There were 124 open items total to date from SSERs 22-25. On the right-hand side of the picture you can see that 41 of those items have been in fact closed. We, TVA, have submitted 39 items for review so 80 out of the 124 are in some stage of closure or review for closure. The remaining 44, a

number of those as Pat mentioned are confirmatory items that will either be closed by the region or by NRR.

We do owe probably about 10 direct responses into NRR for their final review. That's not actually a confirmatory item but additional information that's owed, and right now we're on track over the next two submittals to have those completed by the end of January. So, a number of these items though from a confirmatory nature will go out as we complete the plant because some of them are physical verifications of plants. So that's where we're at today on that. Again as Pat mentioned we can go into more detail offline if you like on some of those specific items.

CHAIR RAY: Well, yes. We're talking about the same thing. We want to make sure that particular open items, not the confirmatory items I don't believe but open items that need some further opportunity for review here that we know which ones those are.

MR. ARENT: Right. Okay. That's all I have. I'm going to turn it over to Bob Bryan who's going to start our discussion on radiation protection.

MR. BRYAN: Thank you, Gordon. Good

morning.

CHAIR RAY: Good morning. As Dave mentioned we live in the Valley and we work at the plant so ALARA is important to us, so we've tried to build that into the plant. That said the basic shielding features for Watts Bar Unit 2 are identical to Watts Bar Unit 1. The buildings report at the same time. The plants are mirror images, they're not slide-alone units so it's, so when you walk on the Unit 2 side the things that are closest together are the common features and as you move out to the things that are closest to the outside wall on Unit 1 or closest to the other outside wall on Unit 2. The ventilation is designed so that you bring air into the upper floors that are clean and exhausted through the dirtier rooms so that you don't spread contamination that way. Because of the layout of the plant a lot of the features that go into the radiation protection such as counting rooms, decontamination rooms and labs were built as common areas that have feeds from both units and so they're shared between the units. The access to the auxiliary building into the radiation zone is common between the two units and so there's not a separate one for Unit 2, it's the same one that's used for Unit 1 and the egress is the same.

MEMBER SKILLMAN: If I could, your point that the units are mirror images intrigues me and I'm curious why you made that point.

MR. BRYAN: A lot of units when they build things the units are slide-along units. So when you walk into one the -- ours is just a little different.

CHAIR RAY: I can weigh in and say having built a mirror image unit and look at 1 Diablo Canyon, getting the reactor vessel back --

(Laughter)

CHAIR RAY: -- can create problems when things are right-handed, they're right-handed in both units which causes the arrangement sometimes to be awkward.

MEMBER SKILLMAN: Well, I wondered if that meant the operators have to be dyslexic on Unit 2.

MR. BRYAN: They have to be really good, but the constructors are the ones that have to be really good because at Sequoyah we did what they did at Diablo Canyon.

MEMBER SKILLMAN: I understand that there is a complication that comes because you can't go from Unit 1 to Unit 2 and expect the identical physical configuration. Got it. Yes, sir, thanks.

MR. BRYAN: Okay. On the NUREG/0737 items

we have done mission dose calculations for Unit 2 that we have updated in terms of some of the differences. I'll be talking about them a little bit later but we have done those and the vital areas of the plant were set up for Unit 1 operation for the single-unit operation so we recast the documentation to reflect the two-unit operation and it'll be next year when we actually transition to the finished plant configuration vital areas for the two units.

Similarly on radiation monitors the coverage is really virtually identical to Unit 1 there. There are a total of 84 radiation monitors shared between the two units, 29 are Unit 1 monitors, 29 are Unit 2 monitors, 26 are common. Eight Unit 2 monitors were put in service to support Unit 1 operation at the time of license so we're adding 21 new Unit 2 monitors. These are almost exclusively in the containment and along the secondary side paths. With the new monitors channel operability test extensions will be based on the operating experience. We have an adequate statistical base to support that. Unit 1 in the original plant, we had a number of local continuous air monitors. They have over time replaced those with portable continuous air monitors maintained by the rad protection people. Unit 2 is following the

same arrangement and will generally use portable monitors for the local continuous air monitors. We're able to use the building-wide range gas monitors to provide the basic 10-deck hour protection requirements and then we have installed continuous air monitors in the fuel pool area. The rest of the plant monitors are done with the portable monitors.

MEMBER ABDEL-KHALIK: Is there an unfiltered in-leakage, control room in-leakage tech spec?

MR. BRYAN: Yes.

MEMBER ABDEL-KHALIK: And will that be changed?

MR. BRYAN: No.

MEMBER ABDEL-KHALIK: Or is it the same --

MR. BRYAN: No, it's a common control room. The control building isolation area is the same for both, it's the same room for Unit 1 and Unit 2. You can look from the Unit 1 horseshoe to the Unit 2 horseshoe. So it shares the same ventilation.

MEMBER ABDEL-KHALIK: So it will remain --

MR. BRYAN: Pardon?

MEMBER ABDEL-KHALIK: It will remain the same as it's always been for Unit 1?

MR. BRYAN: Yes. It shares ventilation

system, it shares the same emergency ventilation system, same filtration system.

MEMBER ABDEL-KHALIK: Okay.

MR. BRYAN: Similarly the rad waste systems are, much of it is shared between the two units. There's a fair amount of operational flexibility though built into the system so that we can manage how much processing that we have to do on the releases. Typically the rad waste systems that treat reactor coolant and its associated waste get a high level of processing but typically on the secondary side we've run very, very clear. And for instance, we don't use the condensate demineralizers except generally in the startup mode and on Unit 1 we've never had to put them in service to handle high source in the secondary side as an example. So generally that waste is just monitored and diluted and released as an untreated release. If we did get a high source in there we are able to process it first by the condensate demineralizers. Then we also have a mobile demineralizer skid that we would treat the regeneration waste with.

MEMBER SIEBER: You said that you don't use condensate demineralizers during normal operation.

MR. BRYAN: That's right.

MEMBER SIEBER: And so you have a boiler blowdown system that's a substitute for that?

MR. BRYAN: We do a steam generator blowdown, yes.

MEMBER SIEBER: Right. And is that a continuous process?

MR. BRYAN: Yes, and it's just monitored and generally released.

MEMBER SIEBER: And what treatment do you provide to the blowdown water?

MR. BRYAN: Right now none other than dilution.

MEMBER SIEBER: Okay.

MR. BRYAN: It's monitored. But if we got a high-level release in there then we would treat it through the condensate demineralizer system. And then depending on how that came out probably would be treated also through the mobile demineralizer skid. But in the 14 years of operation on Unit 1 we've had no issues with just treating it.

MEMBER SIEBER: So let's pretend you get a small steam generator tube leak, you make a decision to continue to operate because it's so small. Your condensates and mineralizers will become radioactive. Your blowdown system if you used it would also be

radioactive. Do you have treatment facilities and procedures to deal with that kind of a situation?

MR. BRYAN: Absolutely, and that's, I mean, that was the way the plant was designed from -- that was part of the initial design. There are radiation monitors in the demineralizer areas. They're set up to be high-radiation areas with the shielding and restrictions. So yes, that's built into the --

MEMBER SIEBER: Right. Some licensees when they encounter that situation are surprised where the activity goes.

MR. BRYAN: Understand.

MEMBER SIEBER: Okay.

MEMBER ABDEL-KHALIK: Let's go back to the control room handling please for a moment. First of all, what is that tech spec limit?

MR. BRYAN: I'm sorry, I --

MEMBER ABDEL-KHALIK: It must be very small. Unfiltered control room in-leakage.

MR. BRYAN: I'll have to find out.

MEMBER ABDEL-KHALIK: I'm just wondering how often do you have to test for that.

MR. BRYAN: Pardon?

MEMBER ABDEL-KHALIK: How often do you

test for that?

MR. BRYAN: Well, once -- Tom?

MEMBER STETKAR: Make sure you identify yourselves.

MR. HILMES: Steve Hilmes, electrical and I&C. Eighteen months surveillance.

MEMBER ABDEL-KHALIK: Right. Has that been challenged, the tech spec limit for Unit 1 during the construction activities for Unit 2?

MR. HILMES: We did -- what do you mean by challenged?

MEMBER ABDEL-KHALIK: Meaning have you exceeded tech spec limits?

MR. HILMES: No.

MEMBER ABDEL-KHALIK: Did you have to enter an LCO because of that?

MR. HILMES: Tom Wallace.

MR. WALLACE: Like the man said, we have a breaching program. If we have to breach a penetration into the control room it limits the amount of open space you can actually have. It's the same space that you would have with the operating side if we weren't here. We can't see any limits. It's there and it's within the design of the plant. As long as we stay within the margin of those breaches and meet

the requirements that are set up with our engineering department to make that particular breach we do not challenge our tech spec.

MR. KOONTZ: Yes, this is Frank Koontz. I can also mention that a lot of, as Tom mentioned a lot of these breaching permits come over to engineering and we evaluate them. For example, if they're doing cable pulls through the walls we'll look at the flow area there, we'll look at whether that's an acceptable flow area you know as far as the in-leakage into the control room or we look at how to seal it up in an emergency if they have to seal it for some reason. If we would have an event then we're required to do that, what they need to do. All that is evaluated under the breaching permit.

MEMBER ABDEL-KHALIK: Usually that tech spec limit is pretty tight and I was just wondering if these construction activities would in any way challenge that limit.

MR. BRYAN: No.

MR. KOONTZ: So far we've not allowed it.

MR. BRYAN: We haven't allowed it. That's what Tom was saying, that basically we are limited as to the maximum breach that we can have in there and --

MEMBER SIEBER: Time and size.

MR. BRYAN: -- and so, by size. And so when we do the construction activities we are not allowed to --

MEMBER ABDEL-KHALIK: It's usually CFM.

MR. BRYAN: Right, but that -- but you can equate that to -- size hole. You know, the exact -- it's under 150 inches, cubic inches.

MR. WALLACE: Oh, yes, that's the problem is a much smaller --

MR. BRYAN: Much smaller than that.

MR. WALLACE: That's for the auxiliary building where we have 117 inches we can work within.

MEMBER ABDEL-KHALIK: For the control room it's much smaller.

MR. BRYAN: Much smaller.

MR. WALLACE: And much tighter requirements, that's correct. Yes, we have to do things like make sure the turbine building ventilation is set up and the doors are properly set. We've got a high energy stimulating the turbine building that it wouldn't factor into the equation.

MEMBER STETKAR: Have you finished pulling all the cables into the control room for Unit 2 yet?

MR. HILMES: Steve Hilmes. No, I haven't completed it all yet.

MEMBER STETKAR: Started?

MR. HILMES: Yes. Quite far along.

MEMBER STETKAR: Okay. So you have -- what I'm trying to -- you have some experience at least and you still haven't entered an LCO during any of the other capables.

MR. HILMES: We don't, yes, we don't enter the LCOs. We figure a way to limit the amount of in-leakage you get when you're opening it up. And there's tricks to the technique to get the cables in.

MEMBER ABDEL-KHALIK: So the tech spec is based on a CFM limit, or based on a whole size limit?

MR. BRYAN: The tech spec's based on a CFM limit.

MEMBER SIEBER: Right. You can calculate the whole thing.

MR. BRYAN: But you can take that and you know what the pressure differentials you're maintaining are and so you can calculate back what an allowable hole size would be with some conservatism. We'll have to get back to you on whether we have ever entered the LCO on control room leakage but to the best of my knowledge we haven't. It's something that we certainly never do routinely.

MR. STINSON: So you're saying no, we've

never --

MR. WALLACE: I can never recall that we've entered the tech spec. We've always stayed within the margin of the breaching program which the system's tested and that's numbers established based on the amount of leakage we had.

MR. HILMES: Steve Hilmes. When they performed the testing you end up with the given margin that you have left and that's what you can work with.

MEMBER ABDEL-KHALIK: And has the last testing been done after you started cable pulling for Unit 2?

MR. HILMES: Yes, it would have had to have been.

MR. BRYAN: Yes.

MEMBER ABDEL-KHALIK: And you passed the --

MR. HILMES: Yes.

MEMBER ABDEL-KHALIK: -- the tech spec during the test?

MR. BRYAN: The other thing was a few years ago when the generic industry issue came out about control room leakage Watts Bar control room design passed adequately. We didn't have to go back and do any of the special activities that some of the

plants did. The tracer gas testing that was done.

MEMBER ABDEL-KHALIK: Okay, thank you.

MEMBER RYAN: Just one follow-up question on the waste area. You've got common waste management systems. Have you evaluated, could you describe a little bit if you have how you looked at stresses from both units coming to that system at the same time, or a combination of different stresses coming to the rad waste area at the same time?

MR. BRYAN: Yes, we have. The systems were designed coming in as to supply two units. You know, it was built, they were sized for two-unit operation. They're very, very similar to the systems that we have at Sequoyah. So we've got good operational history of two-unit operation on these system designs.

MEMBER RYAN: I appreciate that's a normal operating circumstance. What if things aren't normal and you get more rad waste to deal with in both places? What's the head room and your ability to process I guess is one way to think about it?

MR. BRYAN: Well, actually quite a bit. And I was going to get to that here in a minute but --

MEMBER RYAN: Okay, that's fine. Save it for when you're going to get there, that's fine.

MR. BRYAN: Okay. One of the last things that's different in terms of the way we operate today than when Unit 1 was licensed, the original licensing, the plant assumed that we would do 22 containment purges a year at -- Unit 1 has gone to 100 CFM, the continuous filtered vent. Unit 2 is going to operate the same way and so the routine releases were analyzed with that set of assumptions.

MEMBER SKILLMAN: What drives that requirement, please?

MR. BRYAN: Well, two things. We're an ice condenser containment which is a relatively small volume containment so it manages pneumatic leakage into the containment so that you keep your pressures, control containment pressure. And the other thing is it also helps you with keeping the containment relatively clean for the weekly entries.

MEMBER SKILLMAN: Thank you.

MR. BRYAN: We use the ANSI N18.1-1984 search term for doing the routine releases. Things that were different from Unit 1, we updated the meteorology we were using to cover the period of time from 1986 to 2005. This is more or less consistent with the dates that went in with the Supplemental Final Environmental Impact Statement.

The FSAR information was based on the 2007 land use survey. When we do our annual releases we do an annual meteorology and an annual land survey so those are current for the year. The Watts Bar site is very similar to Unit 1. We use terrain adjustment factors for the local site area and then we did our 50 mile population dose, was based on a revised 20-40 year estimate.

MEMBER STETKAR: Bob, here's an off the wall question. You'll probably have to take it away, but maybe not. You have common meteorological towers for both of the units and I was reading about that. It has a data acquisition computer and something called the environmental data station which I'm assuming is at the tower, and it sends meteorological data to the plant, the central emergency control center (CECC) where there's a computer that then distributes it out to the technical support center and I guess eventually the EOP and any emergency planning folks. What are the power supplies for those facilities? Where do they get power to both the EDS and the CECC?

MR. BRYAN: Well, the CECC has its power supplies out of the, I mean, it's basically supplied by the Chattanooga Electric Power Board but it has,

the building has, and that part of it has backup power supplies at the TVA offices. Steve, do you know?

MEMBER STETKAR: Where is the CECC?

MR. BRYAN: It's in Chattanooga.

MEMBER STETKAR: Chattanooga? It's -- has its own diesel? How about the onsite, the EDS?

MR. BRYAN: Well, the onsite emergency center is in the --

MEMBER STETKAR: No, no, no, the data acquisition system, the thing that actually collects the meteorological data, processes it and sends it out.

MR. BRYAN: Steve, do you know the?

MR. HILMES: Steve Hilmes. The tech support center which is --

MR. BRYAN: He's talking about the met towers.

MEMBER STETKAR: The met tower itself. As I understand it, maybe I misunderstood it. The data comes to a met tower, goes into a little data acquisition system. The computer does a bunch of processing, sends it out to the CECC. The CECC sends it back to the tech support center and to, you know, the CECC itself and, you know, whatever other places you use for emergency planning if there are any.

That's at least reading through the brief summary in the FSAR as I understood it.

MR. WALLACE: This is Tom Wallace. The met tower, meteorological tower itself has plant power to it. There's a small interruptible power supply off there for some of the computers. There's also a small gasoline. It's been years since I've been there but there was a gas generator up there as well.

MEMBER STETKAR: I was going to say since it's been awhile since you've been there does anybody ever go out and check whether the gas generator actually works?

MR. WALLACE: Yes, sir. It's done by people up at Kingston plant that do that or one of the facilities that come out and service our meteorological tower up there. It alarms. But we know if the met tower goes down you know it immediately in the control room.

MEMBER STETKAR: I'm obviously thinking about it against the, you know, prolonged loss of offsite power, whether or not you'd actually have real-time meteorological data available for any of your emergency planning action limits.

MR. WALLACE: From our rev you'd have backup in that tower. It's out of -- that you get

from other staples in other locations.

MEMBER STETKAR: Well, but I mean there -- that's okay but it's not Watts Bar-specific, you know, as far as wind speeds and directions.

MR. STINSON: So why don't we take that back and get you a better answer.

MEMBER STETKAR: Okay, thanks.

MEMBER SKILLMAN: Yes, I would like to add onto that if I could. It sounds like from the gentleman's response that the staff at the Kingston station keeps an eye on your met tower physical facility. And I'd be curious whether or not your radiological controls people from your station or your maintenance people that are under the leadership of your station actually do hands-on on the met tower because that is your eyes and ears for an accident.

MR. STINSON: So, Tom Wallace runs operations. Of course he was the operations man.

MR. WALLACE: The people that do the met tower maintenance and manage that stuff out of our environmental group do the -- it's the same equipment for all the TVA sites. They're responsible for each and every one of those stations. But the system itself is smart too and if it goes down it makes notifications to people. There are requirements set

up, frequency-type requirements set up for maintenance that has to be done and maintained, surveillance if you will I guess you'd call it for that maintenance that's required to be done.

MEMBER SKILLMAN: Okay, thank you. Let me ask one more question. The terrain adjustment factors, those were identified in the SER on page 2-4 that TVA was not using the terrain adjustment factors and in this slide you're indicating --

MR. BRYAN: Well --

MEMBER SKILLMAN: Is that a change?

MR. BRYAN: No. We applied terrain adjustment factors basically to the area within about five miles of the site. We did not apply the terrain adjustment factors at, either on Unit 1 or Unit 2 out to 50 miles. We did do some studies of the -- and to understand how we did the terrain adjustment factors the doses are done with a straight line Gaussian program and so we ran a variable trajectory code to get, and looked at the chi over Q's at the locations of interest. And basically if the, for the near site if the variable trajectory code gave us higher chi over Q's we used those. If our straight line Gaussians gave us higher chi over Q's we used those. So we basically picked the worst case in that.

When you go out and you look out to 50 miles we ran the variable trajectory code out all the way to 50 miles and if you apply those to all the receptor locations you end up with doses that are, oh, between about three and five times lower than you would get using the straight-line Gaussian alone. If you take the worst case from all of them you end up with about to the 50 mile total person-rem. You change at about 0.3 rem over to 150 to 1.5 million people. The requirements are that you don't, for terrain adjustment factors that you don't substantially underestimate the dose. We don't feel like we are. So, what it's talking about in the SER is we didn't apply terrain adjustment factors to all the receptors on the 50 mile dose. We did apply them to all within about five miles.

MEMBER SKILLMAN: Thank you.

MEMBER RYAN: What case did you assume to say that you had the worst case? What meteorological condition did you assume to say you are now in the worst case?

MR. BRYAN: We looked at the meteorological, I mean we looked at the hourly meteorology for 20 years and so --

MEMBER RYAN: But you said it was the

worst case so in 20 years the meteorology changes quite a bit.

MR. BRYAN: Right.

MEMBER RYAN: Fumigation is the worst case.

MR. BRYAN: Well, what I meant was when you went in and you calculated the chi over Q's using our straight line trajectory code. So for each receptor I get a chi over Q.

MEMBER RYAN: Yes.

MR. BRYAN: I went and did that again with a variable trajectory code. All right, so now I've got two sets of chi over Q's. If the variable trajectory one was higher we'd pick that value for this receptor.

MEMBER RYAN: Okay.

MR. BRYAN: For this other receptor -- whichever one was higher was the one we used.

MEMBER RYAN: That's not the worst case analysis but that I accept.

MEMBER SIEBER: No, it's not.

MEMBER RYAN: I understand what you did now, but that's most assuredly not the worst case.

MR. BRYAN: I understand, not the worst, worst case. We took the, of those two values we took

the more conservative one.

MEMBER RYAN: You took the higher which is conservative. Did you do uncertainty analyses on those calculations?

MR. BRYAN: No.

MEMBER RYAN: No, so you really don't have much insight into that uncertainty or precision. I'm not arguing what you did, I'm just trying to make sure I understand the characterization of it.

MR. BRYAN: Okay.

MEMBER RYAN: All right, thanks.

MEMBER SKILLMAN: Thank you.

MR. BRYAN: For Unit 1 we used the RM 50 addendum to Appendix I which allows you to set limits based on the site. With two-unit operation we went to the basic Appendix I which puts the limits on a per-unit basis. The one addition that you have to do for Appendix I is you have to do a cost/benefit analysis which we did. It showed that there were no enhancements required. And then I think probably the best thing of all is we've got 15 years of operational data on Unit 1 and it shows that we're a very small fraction of -- what we actually put out is actually a very small fraction of what even the FSAR releases are.

MEMBER RYAN: I appreciate what you said and reading through that it struck me that you really have no insight into uncertainty. What you actually have are a range of values. You did bounding analysis kind of calculations and you were still under, you know, the limits that were set. So I'm trying to understand how you gain insight into variability or margin in those kind of calculations.

MR. BRYAN: Well, I think the most, you know, if you want to go look where a conservatism is and things you go and you look at the -- I mean, you start with the source term. And the source term would be equivalent to about 50 to 60 fuel pins leaking. That's a very, very large number. So, and I think when you go in and you look at what your FSAR releases are compared to your actual releases that really is the basis for most of the differences in them. And so that, I think there's, I guess we feel like there's more than sufficient conservatism there to bound other uncertainties.

I mean, we do, as I say we do look at all the meteorological data and we, for these releases we basically look at averages of the things. When you get over to the accident releases you're picking the things that are in the, you know, 5 percent, top 5

percent area.

MEMBER RYAN: Okay, I'll think about that. I guess what I'm struggling with is trying to understand your insight into what things could go wrong that could mean a bigger difference than other things that could go wrong in those releases. I mean, if they're all low, okay? But which one's more important. They probably have relative importance in terms of if something did go wrong which one contributed more.

MR. BRYAN: I mean, activity in the reactor coolant's most important. Then what your primary to secondary leakages is another key driver. Beyond that it's, I think everything else is at a lower level.

MEMBER RYAN: Thanks.

MEMBER SIEBER: What's the topography around the plant look like? Is it flat or hilly or mountains?

MR. BRYAN: It's a hilly river valley. I mean, the site, there's some local hills very close to the site. The Cumberland Plateau runs north, essentially north-south 5 to 10 miles to the west and off to the east probably about 40 miles you have the Appalachians.

MEMBER SIEBER: Okay. And so do you have occasional or frequent inversions?

MR. BRYAN: There are, at places in the Valley you do have substantial inversions.

MEMBER SIEBER: Traps.

MR. BRYAN: Chattanooga in particular was noteworthy for that. What I think we've seen, as you look at the, now about 40 years of meteorological data for the site what we have tended to see is that overall wind speeds are lower now than they were maybe back in the '70s. We don't have quite as many periods of calm now as we had maybe in the '70s.

MEMBER SIEBER: Have you ever considered using particle cell type codes for dispersion as opposed to gaseous distribution?

MR. BRYAN: There's a yes and no to that. Our meteorological people who do the basic studies for the valley do use the more advanced codes for their studies. For us at the sites because we've got the features built into this one that we need we haven't made the decision.

MEMBER SIEBER: Well, for emergency planning you need realtime data so whatever processing system you use to connect to your met tower plus whatever other inputs you might have, it depends on

what the software does with that data to determine where the radiation levels are high, where they're low and so forth. Usually in hilly country where you have a lot of inversions, radiation doses in the valleys are higher than they are on the hilltops. That can be quite pronounced.

MR. BRYAN: And we, that's -- we also have, we have field teams that go out and monitor.

MEMBER SIEBER: Yes, yes. That takes time to get them out there.

MR. BRYAN: It does.

MEMBER SIEBER: Yes. Thanks.

MR. BRYAN: Last slide. There were, through SSER 24 we had seven open items. Six of those were basically items where we needed to incorporate information into the FSAR that we had previously submitted. The other one was to perform the cost/benefit study. Of these seven we have one that's currently open.

CHAIR RAY: Of the seven what did you say?

MR. BRYAN: We have, we've performed the cost/benefit study and we've updated the FSAR for six of them so we have one that we still need to provide, including with the FSAR.

CHAIR RAY: Okay.

MR. BRYAN: That completes this part of the presentation.

CHAIR RAY: All right. I believe you're going to also do the next one.

MR. KOONTZ: Well, I've got -- this is Frank Koontz.

MR. BRYAN: We can move ahead and go to dose consequences.

CHAIR RAY: You want to go to dose and then come back? That's fine. What's on the agenda is radiological consequences of accidents.

MR. BRYAN: Okay. For the accident dose, for all of the accidents the dose consequences are of course less than 10 CFR Part 100 and also for those where you're supposed to be substantially below the Part 100 limits we meet those. The next bullet shows basically the regulatory criteria that we were meeting for each of the different accidents that we evaluated for dose. If you want to flip to the next slide.

Things that were different from Unit 1. For the accident analysis we updated the meteorology to get the chi over Q's based on a 20-year period from 1991 to 2010. Unit 2 has the original steam generators in them which have a slightly smaller primary and secondary volume than the replacement

steam generators at Unit 1 so we've accounted for that. We don't have tritium-producing rods in Unit 2. The dose equivalent iodine for these analyses was reduced to the tech spec limit and then we revised our fuel handling accident for the accident in the auxiliary building to use alternate source terms. The one for the containment, with the containment isolated still uses the Reg Guide 1.25 analysis. The fuel handling accident for -- in the containment with the equipment hatch open is bounded by the action in the spent fuel pool and so that analysis covers the containment open case 2.

CHAIR RAY: That's the containment open to the auxiliary building, right?

MR. BRYAN: Yes.

CHAIR RAY: Not to the exterior. What's the reason for that assumption? I couldn't find why you need to know more about how you operate I guess to understand why you wouldn't assume open to the outside, the door opened to the outside.

MR. BRYAN: Because once you get the head removed and you're flooded up you open the equipment hatch so you have ready access to the containment for maintenance work and other outage activities.

CHAIR RAY: Well, maybe I'm asking the

question unclearly. Why is it not assumed that the door to the exterior rather than to the auxiliary building is open?

MR. BRYAN: It doesn't have a door to the auxiliary building.

CHAIR RAY: Well, or -- but the auxiliary building is open to the outside. I'm just trying to recall what I read in the analysis which is that the door is open to the auxiliary building, not to the outside.

MR. BRYAN: That's true. The equipment hatch goes to the auxiliary building. It does not go to the outside and the auxiliary building is kept closed from the outside.

CHAIR RAY: I misunderstood the comment then I guess. It made it sound like to me that there was an assumption being made about there not being an opening that could have existed but doesn't, and you're just saying there isn't any such possibility.

MR. BRYAN: There isn't such possibility, no.

CHAIR RAY: All right. I misunderstood.

MR. BRYAN: Okay. The other things that were slightly different from Unit 1, a lot of even the emergency ventilation systems are shared between the

two units. So typically even for events in Unit 2 releases could come off of the Unit 1 shield building stack and that tends to be for, for LOCA as an example that's still the limiting event. For events that have releases off of the secondary side that go out through our valve vault, steam line rate, tube rupture and loss of AC. The path from the Unit 2 valve vault to one of the control building intakes tends to be the limiting path. So for Unit 2 they were analyzed on the basis of that.

MEMBER SKILLMAN: May I ask you to back up to slide 31, please? The bases for these analyses. These reg guides have in their lifetime gone through various revisions and upgrades. May I ask you to please comment on whether or not you have used a new or different version of a reg guide so that your analyses for Unit 2 are successful where they would not have been had you used the previous version of the reg guide? I'm just asking if you're cherry-picking.

MR. BRYAN: No. The only place that was for the fuel handling accident we changed some damper timing, damper closure timing and that would have applied to Unit 1 also. And using the alternate source term was advantageous for that but relative to the older reg guide analysis.

MEMBER SKILLMAN: Because I read it, your real conservatism for your fuel handling accident is the 23 feet of water over the drop assembly. That's what really gives you the lower amount that is released because so much is removed by the column of 23 feet of water.

MR. BRYAN: Right and that's what the alternate source term lets you take advantage of.

MEMBER SKILLMAN: Is that the same for Unit 1?

MR. BRYAN: For Unit 1 they are running, currently they were using that as an engineering evaluation of their damper condition. They are in the process of submitting the license amendment request to change their analysis basis to the alternate source term for fuel handling accidents also.

MEMBER SKILLMAN: Thank you.

MR. BRYAN: If there are no more questions I'll turn it over to Frank Koontz.

CHAIR RAY: Okay. We're a little ahead of schedule so we can go ahead and I think do this next piece and then we'll take a break.

MR. KOONTZ: Okay. This is Frank Koontz. I believe some of this information on Chapter 15 may have been covered at the last meeting. I wasn't at

the meeting. I was actually in Hawaii so I was going to say I missed the last meeting but I didn't.

(Laughter)

MEMBER STETKAR: You were absent.

MR. KOONTZ: I was absent from the last meeting. One of the things that we wanted to make a point of here is that the Unit 2 analyses that we did for Chapter 15 were generally similar to the ones that we had done for Unit 1 at the operating license for Unit 1. Some of the similarities is that we have the original steam generators in Unit 2, that's the model D-3 Westinghouse steam generators. Since the original license on Unit 1 they have upgraded the steam generators and they have gone to a new model 68AXP but we still have the original ones.

We do not have credit for a measurement uncertainty recapture. That's a leading edge flow meter. We do have that hardware installed but we're not asking for that under our initial license. That's similar to what Unit 1 had at their original license is they did not have LEFM installed at that time so our startup power is 3411 megawatts thermal NSSS, our reactor power. So those two are very similar to the original license.

Some of the things we did update and some

of the differences is what I'm going to talk about next. The first thing we did is we re-baselined the large-break LOCA and the small-break LOCA. We decided that we wanted to get away from the old BART/BASH methodology on large-break LOCA. We had gone to a best estimate analysis with Westinghouse on Unit 1. We wanted to do that best estimate analysis on Unit 2 and so we updated it with the ASTRUM methodology and that's what we've got for Unit 2. We did see a difference in the peak clad temperatures. For example, the Unit 2 95th percentile peak clad temperature under ASTRUM is 1552 so that gives us a large margin to the 2200 degrees.

We understand there is an Information Notice the NRC sent out with respect to PAD, their fuel thermal performance model and how that might affect ASTRUM but we do have a large margin there. And I don't know if we mentioned PAD but we're working with both Westinghouse and the Owners Group to see what we need to do to update that PAD code to put in the variable thermal conductivity as a function of burn-up, but that'll take awhile.

The benefit we've got there, the positive that we've got is that the thermal conductivity effect doesn't kick in for awhile as far as burn-up and so we

are in pretty good shape for at least the first cycle for Watts Bar Unit 2. But that would not be an impact to us and the NRC staff is looking at possibly a license condition on Watts Bar Unit 2 to resolve that issue before we get in the first refueling.

For the small-break LOCA we re-baselined that. We used the NOTRUMP code similar to what we use on Unit 1 and similarly there we've got a pretty large margin. Unit 2 came out around 1184 degrees Fahrenheit for the PCT for Unit 2.

Some of the other things we did in Chapter 15 is we had several new analyses. The next slide there, Gordon. One of the things the staff asked us to look at was overpressure protection on the second trip. Our Westinghouse analysis had looked at a turbine trip event as causing a peak overpressure on the system and but it credited the first safety grade trip. It was on the pressurizer. And the staff said well, the Standard Review Plan really says look at the failure of the first trip and model it as if it tripped on the second trip. So we went back and we re-analyzed that for the staff. We did get acceptable results. It didn't make a large difference. For example, the limit is 2750 psia, that's 110 percent of the design pressure. The original trip came in at

2691 psia and when we went to the second trip it came in at 27, around 2715 psia. So we still have a margin, that limit of 2750. So the staff accepted that and they may talk about that this afternoon.

They also asked that we look at a CVCS malfunction event. We had not looked at that for Unit 1. What we did look at was an inadvertent SI and we had made the case that that was bounding to the CVCS malfunction. The difference in those two events is for an inadvertent SI you get an immediate reactor trip on the safety injection. For a CVCS malfunction it may be something like a charging pump control failure of some type, that the charging starts to over-charge and perhaps the letdown isolates and then you're filling up the pressurizer. And the question on that event is whether it will fill the pressurizer and actually relieve water through the PORVs on the pressurizer and whether the PORVs are qualified for water relief.

So we had Westinghouse go back and analyze several cases on CVCS malfunction. We were able to show that we did not get to a point where we had water relief through the PORVs, that the operators could terminate that event in a timely fashion.

MEMBER ABDEL-KHALIK: In which mode?

MR. KOONTZ: This is in power mode, mode 1.

MEMBER ABDEL-KHALIK: Have you analyzed that during modes 4, 5 and 6?

MR. KOONTZ: No. We haven't looked. We believe that the power mode is bounding. We do have the staff here from Westinghouse that did the analysis. Ryan, would you like to comment? Would there be any differences in the lower modes? Or Alan, or Chris, either one of you three guys, that you believe would be more limiting.

MR. MCHUGH: This is Chris McHugh from Westinghouse. Thermal remotes are not typically a problem because it's conservative less decay heat. If you turn decay heat off at mode 1 it takes forever to fill. It's really a combination of the SI and the decay heat cause the thermal expansion. So there's a lot more time in lower modes than there is in mode 1.

MEMBER ABDEL-KHALIK: We heard a different story for another licensing action so you may want to consider.

MR. KOONTZ: And that's for the CVCS malfunction? Because I know we also get into the lower modes in the boron dilution event also.

MEMBER ABDEL-KHALIK: Right.

MEMBER STETKAR: Do you want, when you shut down on Unit 1 do you basically fill the pressurizer solid? How do you do gas on Unit 1? I don't know how plants do it.

MR. KOONTZ: The question is how do we go through the shutdown process.

MEMBER STETKAR: When you're coming down, when you do degassing and you're coming down, do you cycle pressurizer level essentially full?

MR. WALLACE: Yes, sir. We will carry the pressurizer solid. We'll continue to run solid all the way through de-gas and cleanup.

MEMBER STETKAR: Decay heat is still pretty high at that time because that's typically the first day or two. Okay, thanks. There's a vulnerability, for example.

MR. KOONTZ: Yes. Well, we do have protection systems there for coms and you know, safety valves to protect the system if there was water solid.

MEMBER STETKAR: Are your PORVs qualified for water relief or not?

MR. KOONTZ: Well, not through a regulatory process. I mean, the PORVs are the target rock models. They were successful in some of the EPRI valve testing as far as water relief so I think the

case could be made that they would qualify. And we did look at the civil analysis on the tailpipes and the tailpipes will withstand the water relief load. We haven't made that case at the NRC so I'd say in a licensing space we're not qualified.

MEMBER STETKAR: But they're the target rock.

MR. KOONTZ: They're the target rocks, yes.

MEMBER SIEBER: Do you have loop seals on the discharge side?

MR. KOONTZ: Not on the PORVs. On the safety valves we used to have the loop seals on the safety valves but we drained the loop seals and put in the associated trim for the safety valves. We found that the slug loads from clearing the loop seals on the safety valves were just too high.

MEMBER SIEBER: You have to do a lot.

MR. KOONTZ: So even on Unit 1 a long time ago we learned that lesson and drained the loop seals out. And that's one of the things we're trying to show to the staff is that we didn't get water relief which would challenge either the PORVs or the safety's. The safety's in the EPRI valve test had a little harder time passing water. They tend to

chatter and then gall and stick, and then you have a potential of moving to a more severe event like a small-break LOCA. So that was the goal of the analyses was to show that we wouldn't challenge the PORVs or the safety's.

One of the other analyses that the staff was interested in was the core response to the main steam line break. And the principle problem was a couple of things. They were a little bit concerned comparing Unit 2 to Unit 1 that we had a better return to power, in other words a lower value. They didn't understand that, compared to both Unit 1 and other plants that they had seen. So one of the things we did to --

MEMBER ABDEL-KHALIK: In terms of what, your NTC?

MR. KOONTZ: In terms of the peak heat flux, return to power.

MEMBER ABDEL-KHALIK: Because you have different core design?

MR. KOONTZ: Well, it wasn't so much different core designs as it was different conservatisms in the reactivity coefficients that we had used in the analyses. That was one thing. And we were able to deconstruct for them the results going

from Unit 2 all the way back to Unit 1 showing as we changed each of the parameters back how it went from the Unit 2 results all the way back to the Unit 1 results so they could see, you know, what the changes did and how those affected the results. And what we ended up doing was re-running the main steam line break core response using consistent reactivity parameters, in other words, same amounts of conservatisms in both analyses and the staff was able to see then that they had the right relationship between the loss of offsite power cases and the power available cases, and then also how that compared to Unit 1 including the shutdown margins that we had committed to on Unit 1 in the analysis versus the Unit 2 analysis. So they became satisfied that the main steam line break indeed was responding as they thought it should. And a lot of it was due to this conservatism that was held up in some of the reactivity coefficients.

MEMBER ABDEL-KHALIK: What is your tech spec limit on the NTC at end of cycle?

MR. KOONTZ: Well, we're -- Tom? I think it's zero. We do not allow it to go positive.

MEMBER ABDEL-KHALIK: End of cycle.

MR. KOONTZ: Oh, the end of cycle.

MEMBER ABDEL-KHALIK: Hopefully is a big negative number.

MR. KOONTZ: I don't know. Do you know the tech spec, Pat? You, Chris, or Tom?

MR. WALLACE: No, not off the top of my head I don't.

MR. KOONTZ: We can find that out if you want to know what it is.

MEMBER ABDEL-KHALIK: Okay.

MR. KOONTZ: Some additional analyses that we did. We did re-look at the inadvertent ECCS analysis. As I mentioned earlier we had looked at it on Unit 1 from the perspective of not challenging the safety valves. We were worried about the Crosby 6M6 safety valves. Like I mentioned they did perform poorly in some of the EPRI tests as far as water relief. So what we did in our original safety analysis is we assumed the PORVs were blocked and then that would maximize the challenge to the safety. In other words, we didn't credit any relief through the PORVs. We made it look to see if it would challenge the safety's, relieve water through the safety's.

That's a good safety analysis. The staff didn't accept that though. They had issued a RIS 2005-29 and the RIS was actually oriented towards if

you did credit the PORVs then you need to show they're qualified and they can relieve water and whatnot to protect your safety's. Well, we hadn't done that but they asked the question what if the PORVs got challenged. Then how would you handle that? So we went back and we re-analyzed the event and were able to show that even if the PORVs were allowed to open that we didn't challenge the PORVs, that they would not pass water and that the peak reactor, or peak pressurizer level remained below the top of the pressurizer. So we got acceptable results. They would not challenge the PORVs or the safety's. Neither one would pass water.

MEMBER STETKAR: That's based on a timing analysis for operators?

MR. KOONTZ: It's based on timing, it's based on 10-minute operator action time and time for the operators to respond to the event. Any other questions on that?

CHAIR RAY: Said, did you want to make a more definite request with regard to the CVCS and other modes?

MEMBER ABDEL-KHALIK: I would like to see that.

CHAIR RAY: Okay.

MR. KOONTZ: Okay, so CVCS malfunction and shutdown events.

MEMBER ABDEL-KHALIK: Right.

MR. KOONTZ: Shutdown modes. Okay.

MEMBER STETKAR: Yes, I mean, you know, we worry primarily is going down when the system is still tight and the level is high. You know, and there are a couple of time windows in there that you're vulnerable to those types of malfunctions. You know, pressurizer.

MR. KOONTZ: Pressurizer, yes.

MEMBER STETKAR: Overfill --

MR. KOONTZ: Overfill in the pressurizer.

MEMBER STETKAR: -- malfunctions.

MR. KOONTZ: One of the other analyses the staff was interested in was boron precipitation. We have the same tech spec requirements for our boron that we have on Unit 1. Unit 1's are based principally on the fact that they have the tritium-producing burnable absorber rod so they have to maintain a higher boron concentration in the accumulators in the RWST to offset lithium that's lost during a large-break LOCA. To lower operator confusion we decided to keep the same tech specs for Unit 2 and what that does, it results in a time-to-

hotleg recirc around three hours as what we use for both Unit 1 and Unit 2. So the staff wanted to reassure themselves that that was a conservative time. So we had performed calculations to show it was in the order of five hours is when you'd really need to go to hotleg recirc and we gave the staff enough data that they could independently do their own confirmatory analysis. And they may talk about that this afternoon. But they also came up with acceptable results so the three hours was considered a good time frame.

One of the open items that we have on the Chapter 15 transient analysis is the boron dilution and at the last meeting we indicated that we had just started looking at that. This was boron dilution in modes 3, 4 and 5. We had the analysis in the FSAR for modes 1, 2 and then the refueling shutdown mode 6. So we went back to do explicit analysis on modes 3, 4 and 5, and one of the things we did first was that we went over to the simulator and ran some tests. Bob and I both went over there and observed some of the indications that came in that would alert the operators that they had a boron dilution going on in modes 3, 4 and 5. Then we went off and did the Westinghouse safety analysis because it's a more

conservative model to see what kind of timing would result for operator action. And the goal in these studies is to show that the operators have at least 15 minutes to respond from the time they get the alarm or indication that there's a dilution event going on until they can go out and secure the system so that it doesn't go re-critical.

That analysis is just now getting to completion. Chris McHugh has been working on that at Westinghouse. We haven't submitted the results to the NRC yet so this is preliminary information but we did get acceptable results in mode 3 that the time from alarm to re-criticality ranged from, depending on which case we were running 36 to 97 minutes. So there was quite a bit of time for the operators. In mode 4 it ran from 36 to 58 and in mode 5 we had cases running from 22 to 29 minutes. Of course that's subject to staff review and they'll look at the conservatism we had in the models and see if they concur with us on those. And we'll probably submit those perhaps by the end of the year we can get it through checking and review.

And that's really the most controversial things I guess out of the staff reviews on Chapter 15. Most of the other analyses that they looked at were

pretty similar to Unit 1 and although we had a lot of RAI questions on each event these were the ones that they concentrated on. That's the only thing I have.

MEMBER ABDEL-KHALIK: What is your peak pressure for the loss of feedwater ATWS?

MR. KOONTZ: Ryan do you know, or Chris? We can look it up. I don't remember what it is off the top of my head.

CHAIR RAY: Okay. Because Said you're not able -- we have two meetings running today and Said won't be with us this afternoon. Would you like us to try after the break to bring forward the staff discussion comparable to this Chapter 15 discussion we've had here?

MEMBER ABDEL-KHALIK: That would be good.

CHAIR RAY: Pat, can you do that?

MR. MILANO: Yes, our transient analysis reviewer, we've called him and he should be on his way over here now.

CHAIR RAY: All right, because we're supposed to hear from the region but because of Said's having to attend two meetings today I think it would be helpful to the subcommittee if we could have the staff do their review comparable to what Frank has done after the break. Okay? Anything else?

MEMBER ABDEL-KHALIK: If that's okay with the person from the region. He may have travel scheduled.

CHAIR RAY: Well, yes, I was hoping that I could assume that but I shouldn't. Thank you. All right. So we'll try and do that. But before we adjourn for the break let's see if there's any other questions for TVA.

MR. ARENT: We do have one follow-up item. This is Gordon Arent. To your earlier question regarding the tech spec limit for in-leakage it's P1 CFM 51, 51 CFM. And that is tested on an 18-month period.

MEMBER ABDEL-KHALIK: No, the question really is whether, given all the work that you're doing in the control room, whether that testing frequency is still okay.

MR. ARENT: And we'll confirm that. But again, it is looked at each time we perform a penetration into that boundary so.

MEMBER ABDEL-KHALIK: Right. It is a very small number.

MR. ARENT: Yes, it is.

CHAIR RAY: Yes, I think the issue would be has experience shown that it's unlikely that you're

violating that unaware during the work that's ongoing. Okay. If there's nothing else we will take a break until 20 minutes to 11, 20 minutes to 11. And then hopefully we can shuffle the agenda here so that the item 11 on the list here which is the transient analysis --

MEMBER ABDEL-KHALIK: He's here.

CHAIR RAY: Okay, good. Then we will resume with the staff will come forward with that discussion. And then we'll pick up with the agenda with the region before lunch. We are in recess.

(Whereupon, the above-entitled matter went off the record at 10:20 a.m. and resumed at 10:41 a.m.)

CHAIR RAY: Back on the record. And before the staff makes the presentation that we asked for before the break TVA has asked to respond to some questions that were left open.

MR. KOONTZ: Yes, this is Frank Koontz again. We were able to determine some of the responses for your questions that we had this morning during the break. One of the questions surrounded the met tower and its backup capabilities. And what we determined there is that the system is configured with a 30-minute uninterruptible power source and then

there's a propane-driven 30 kilowatt generator as a backup to that. So that was the met tower.

There was a question on the end of cycle moderator temperature coefficient. And it's not in our technical specification but it's in our core operating limits report, and it's listed as -4.5 times 10^{-4} and that's delta-k/k degrees Fahrenheit.

And then there was a second question similar to that on the ATWS event. And what we do there is we follow the generic methodology in WCAP-8330. And for the loss of normal feedwater event which is the one you mentioned the peak pressure is 2725 psia and for the loss of load turbine trip event it's 2780 psia. And we still have the outstanding question on this in modes 3, 4 and 5.

MEMBER ABDEL-KHALIK: Thank you.

MR. KOONTZ: That's all I have.

CHAIR RAY: All right, thank you. Now to the staff.

MR. MILANO: I'll just do a quick introduction. The lead reviewer for the accident transient analysis from the Reactor Systems Branch was Samuel Miranda and Mr. Miranda will be presenting the results of his, or the findings he obtained during the course of his review of Chapter 15.

MR. POOLE: I think, you know, Pat opened it up. Frankly, as part of the request we're jumping ahead to Sam's portion of the review which was Chapter 15, Transient Accident Analysis.

MR. MIRANDA: Good morning. My name is Sam Miranda. We met yesterday. I ended up, the Reactor Systems Branch part of the review of the Watts Bar license application. And I'll give you a summary of what the major issues were during this review. I'll follow that structure there, review procedures, results. We selected a few aspects of the review that presented some challenges to the staff and finally the conclusions.

We were instructed in this review to refer to the Watts Bar Unit 1 analyses. They had been reviewed and approved and basically we were asked to look for any differences that might have occurred between the time at Watts Bar Unit 1 and Unit 2. But as we got into the review we found that it was more complicated than that and things had come up in that intervening time period. And some of our findings it turned out would also apply to Unit 1. And we'll see that later on.

The analytic methods that were used were approved methods for both Units 1 and 2. And we also,

during our review we tried to keep a perspective on this plant. Since it is such a dated design we wanted to compare it to other plants of a similar design and power level. This did result in several rounds of RAIs and I have to admit some of the responses we got did not really answer our question so we had to do several rounds of RAIs and we had to do two audits. The first audit, there were many questions that remained. We had to settle them finally in June in the second audit, two-day audit.

We have the benefit of a Safety Evaluation Report. We had 22 supplements of the Safety Evaluation Report to look at, and it provided a long history of analyses and reviews dating back to '84 I think, or actually earlier than that. And we found that the results we have received from Watts Bar Unit 2 were acceptable with sufficient margin. They met the acceptance criteria that applied.

We did single out five accident analyses that we had some issues with and we'll go through these individually. The first was the overpressure protection analysis. In that case the Standard Review Plan specifies that the reactor trip that is credited in the analysis should be the second safety-grade trip. And the analysis that we received with the

application credited the first reactor trip. The second issue with the CVCS malfunction event, it simply wasn't in the licensing basis. It wasn't in the FSAR and I pointed out to TVA that this should have been submitted way back when Watts Bar Unit 1 safety analyses were submitted. It was specified in the Reg Guide 1.70, the standard format for -- standard format and content for the safety analyses reports. It's listed as one of two mass emission events in Table 15-1. And eventually we received that analysis. We had an issue with the inadvertent ECCS actuation of power and that's a long story which we'll get into in further slides.

We asked for a boron dilution analysis in modes 3, 4 and 5. TVA had submitted analyses in modes 1, 2 and 6. And the steam line break had a number of issues that we'll describe later.

So as I said we were looking for an analysis in which the second reactor trip signal was credited. We didn't get that. We got a copy of the overpressure report, certified overpressure report and in that report it said that the first reactor trip signal was credited. TVA was trying to argue that the first reactor trip signal was the trip signal that is received from the turbine hall and that was not

accepted by the staff. The trip coming from the turbine hall is not considered qualified since it's coming from a non-seismically qualified source. So we're looking for the second reactor trip signal from the reactor protection system. Usually the first signal is the high-pressure followed by an over-temperature delta t. When that signal occurs we assume the reactor is tripped and the peak reactor coolant system pressure that is attained during the analysis which is a loss of load analysis is the limiting pressurization transient. And that is verified to be less than 110 percent of reactor coolant system design pressure. In TVA's case it went up from something like 2694 psi in the previous analysis to the 2714 psi, still below the 110 percent of design pressure which is something like 2750 psi.

As I said before the CVCS malfunction is missing. We asked for it. TVA had argued that this event was bounded by the inadvertent SI actuation event and our response, the staff's response was yes, the flow rate is lower for this case. It's usually less severe than the inadvertent SI actuation event but it's a different transient, different things happen and it's not exactly an apples to apples comparison that we would have to see an analysis. And

the analysis results indicated that there was adequate time for manual mitigation. It was 10 minutes or more available for shutting off the charging flow, and it was bounded by the SI actuation event although it's not necessarily true that the inadvertent SI actuation event would always bound this case.

MEMBER STETKAR: Sam, a couple of questions on that to look at. Is there a requirement for the applicant to perform a feasibility analysis for that nominal 10-minute time window or is it just presumed that people are always 100.00000 percent successful because they have nominally 10.0000 minutes to mitigate this event regardless of its cost? For example, if local operator actions are required out of the plant to turn the pumps off. So, the basic question is is there a requirement to perform what, you know, we typically call a feasibility assessment that indeed those actions can be performed within 10 minutes.

MR. MIRANDA: We have been, we have been presuming that 10 minutes is sufficient time for operator action. And the practice has been that if 10 minutes is shown by analysis to be available then we accept that. If it's less than that then we ask for a verification through simulator exercises.

MEMBER STETKAR: So 9.9999 minutes you need an analysis, 10.0001 minutes the operators are guaranteed success?

MR. MIRANDA: That's what it amounts to, yes.

MEMBER STETKAR: Okay.

MR. MIRANDA: Yes.

MEMBER STETKAR: You weren't here when we were discussing the CVCS malfunction event with TVA. The question arose about possible CVCS malfunctions during modes other than power operation 3, 4, 5, 6. The 10-minute time window here I assume was for a CVCS malfunction that is initiated at normal pressurizer level. There are conditions when a plant is shutting down, in particular degassing operations where they actively fill the pressurizer almost water solid. The CVCS malfunction that occurs during those conditions gives the operators, oh, essentially zero time before you actually challenge whatever relief capacity you have, depending on how they actually do the degassing operations. Have you looked at all, asked TVA about those types of malfunction events? Because, you know, arguments are that, well, decay heat is much lower. It's actually not when you're coming down because they typically do the degassing within the first couple of

days of the outage. So decay heat levels still can be, you know, not as high as immediate post-scram but still interesting. Have you asked TVA about those other malfunctions during non-power conditions?

MR. MIRANDA: Well, the Reg Guide 1.70 specifies that the limiting case should be presented in its safety analysis report, and the limiting case usually is at full power. In this case --

MEMBER STETKAR: Excuse me. The limiting case is usually at full power because nobody's ever thought of non-power conditions. That's why the limiting case in the regulations is at full power because nobody's ever thought of non-power conditions.

MR. MIRANDA: We've thought about it.

MEMBER STETKAR: Okay. That's what I'm challenging.

MR. MIRANDA: We thought, for example, one of the questions we asked was we wanted analyses of the boron dilution in modes 3, 4 and 5. Those studies had been done in the past looking at different accident analyses in the lower modes and the determination had been made that there's less margin available at full power.

MEMBER STETKAR: Absolutely.

MR. MIRANDA: In this case for the CVCS

malfunction we didn't ask for analyses in lower modes. Part of that is covered by LTOP and that's considered elsewhere in the FSAR.

MEMBER STETKAR: The only question though is if there -- you said LTOP but if the valves aren't qualified for water relief or if there's a reasonable chance that they might stick open you now have an inventory control problem. So.

MR. MIRANDA: Yes.

MEMBER STETKAR: You know, LTOP is good, they'll probably open the valves pretty quickly if it's in service under those conditions and it probably is, but that still doesn't solve the water relief problem through the valves.

MR. MIRANDA: Well, you can reasonably argue that the valves are qualified for water relief based on the fact that that you are at reduced temperature, that you're passing subcooled water through those valves. Okay. Because the valve tests, the valve tests are conducted for various transients and for various water conditions up to saturation. And I think the results show that when you, as you go away from saturation that the valves are --

MEMBER STETKAR: Is this for PORVs?

MR. MIRANDA: Yes.

MEMBER STETKAR: I'm not talking about the safety.

MR. MIRANDA: Right, the PORVs. Right. Right. And there are some PORVs that, the ones I can think of offhand are target rock valves that are qualified for water relief under any condition based on the test results. So it depends on the plant and the conditions and part, some of those lower modes which fall into the LTOP region where you have analyses of relief through those valves, through the PORVs either due to mass addition from the charging system or due to a heat addition of some kind.

MEMBER STETKAR: Yes, most of them I've seen look at the heat addition part of it, or mass addition, you know, making the argument about the time available for somebody to stop the mass addition. But there are admittedly short, but there are time windows where that available time for operator intervention can be pretty short where you do -- the only thing you have mitigating an overpressure transient is basically LTOPs. And then qualification valves then comes into question.

MR. MIRANDA: Right, and those valves for LTOP are set to a much lower pressure. And also, when you're in the lower mode you also consider what

systems are operating and available. So for example, if you're, say if you're in mode 3 or even mode 4 you wouldn't have the, wouldn't necessarily have pressurizer level control in the sense that, you know, you wouldn't have a failure there so what would be your postulated failure would have to be an operator error.

MEMBER STETKAR: Operator error or some sort of electronic or control system malfunction.

MR. MIRANDA: Yes, and a lot of those control systems would not be operational. There's no automatic control there, it's just, you know, whatever the operators are doing. And you can reasonably argue that, you know, an operator making an error would realize it rather quickly and correct it. You know, having his hand on the switch and he says oh, I shouldn't have turned that switch. I'll turn it back again.

MEMBER ABDEL-KHALIK: Wouldn't that be the case with the boron dilution transient during these modes that you ask them to do?

MR. MIRANDA: Yes. The boron dilution is a plant operation and you start the boron dilution, so many gallons in so many minutes and so on. And that, the boron dilution is, I believe is usually an

operator error. Yes.

MEMBER ABDEL-KHALIK: But there your criterion is to give them 15 minutes.

MR. MIRANDA: Yes, it's 15 minutes in modes 1 through 5 and 30 minutes in mode 6. Yes.

MEMBER ABDEL-KHALIK: What I'm trying to say is that your logic is inconsistent.

MR. MIRANDA: It is. I didn't make it, I just followed -- these are the safety analysis conventions that have been adopted over the past 40 years. It's 15 minutes for operator action in boron dilution, it's 30 minutes for operator action in most events and for the mass addition events it's come to pass that 10 minutes is accepted. Anything less than 10 minutes we demand simulator exercises. I can't support it any further than that.

CHAIR RAY: Well, we appreciate the candid summary anyway. Thank you.

MR. MIRANDA: The inadvertent ECCS actuation. The analysis we received -- well, let me back up a little bit on this. The inadvertent ECCS actuation is an event that is classified as a condition 2 event. It's an anticipated operational occurrence. It happens, it has happened. It's happened at Millstone 3, it's happened at Salem. The

pressurizer does fill and the PORVs open. So far a PORV has not failed to open although some PORVs when they receded were leaking.

The analysis we received from TVA consisted of an inadvertent ECCS actuation, the maximum safeguards flow, but the PORVs were not assumed to be operational. And the logic there was without the PORVs they did an analysis showing that the maximum pressurizer pressure achieved during this event did not reach the safety valve opening setpoint. And they said well, we've demonstrated that we won't open the safety valve. It's important not to open the safety valve because the safety valve once opened and failed open is not isolatable. The PORVs we don't need to worry about because the operator can always close a block valve. That was their logic and --

MEMBER ABDEL-KHALIK: What is the shutoff head of these pumps?

MR. MIRANDA: The shutoff head is usually, it's very close to the opening setpoint of the.

MEMBER ABDEL-KHALIK: Let me just try to ask a specific question. What is the shutoff head of these pumps and what is the flow rate that you would get at the normal operating pressure?

MR. MIRANDA: I don't know offhand what

the flow rate is. The shutoff head of the charging pumps is usually around 2,600 psi. The opening setpoint of the safety valves is 2,500 psi.

MEMBER ABDEL-KHALIK: I understand all that, I'm just trying to get a feel for what is the flow rate when these pumps are actually actuated at normal operating pressure.

MR. MIRANDA: We've got that information. Let me see if I have it. I don't have the currents with me but that information is available. We can go back and get that information.

MEMBER ABDEL-KHALIK: Thank you.

MR. MIRANDA: In fact, it's a question that we sometimes ask, you know, give us the flow delivery curve. We have received that.

MEMBER ABDEL-KHALIK: So just continue.

MR. MIRANDA: Okay. So the results of the analysis showed that the peak pressure that was achieved was just under the opening of the pressurizer safety valve setpoint, just below that. And we said well, there you are. If we have such an event we're not going to open the safety valve. Therefore, we're okay.

MEMBER ABDEL-KHALIK: Now, let me ask you a question. If the shutoff head of these pumps is

above the setpoint of the safety valves what terminates the transient?

MR. MIRANDA: The transient is not terminated.

MEMBER ABDEL-KHALIK: What limits the peak pressure?

MR. MIRANDA: The peak pressure is basically the run-out of the shutoff head of the charging pumps and what you have here is --

MEMBER ABDEL-KHALIK: You just said that the shutoff --

MR. MIRANDA: I know.

MEMBER ABDEL-KHALIK: -- head is higher than the --

MR. MIRANDA: Right, I said that. What we have here is we have a pressurizer that's so many feet high, the safety valve is on top of the pressurizer and the pressure, there's an elevation head involved here. You have flow coming in from the charging pumps. It's going to be a very small flow at the shutoff head, 2,600 psi or something below 2,600. And as it goes through the reactor coolant system there are pressure drops along the piping and then there is the elevation head to get from the search line up to the top of the pressurizer where the safety valves are

located. And that elevation head, the difference in the pressurizer pressure compared to the reactor coolant system hotleg pressure is usually something like 80 psi.

MEMBER ABDEL-KHALIK: Are the reactor coolant pumps assumed to be tripped during this event?

MR. MIRANDA: No. No, they're not. Nothing happens during this event. It relies on operator action. The operator has to recognize what's going on and following procedures of what -- let me revise that. The reactor is tripped at time zero because the safety injection signal also trips the reactor.

MEMBER ABDEL-KHALIK: Right.

MR. MIRANDA: And then the operator, then nothing else happens. The operator has to follow emergency operating procedures to diagnose what's happened here and determine that the proper course of action is to shut off the safety injection. And he has basically 10 minutes to do that.

MEMBER ABDEL-KHALIK: So the peak pressure that's -- maybe if the licensee can answer this that would be very helpful. The peak pressure is limited to a value below the setpoint of the safety's even though the shutoff head of the pumps is greater than

the setpoint of the safety's because of what?

MR. MACDONALD: This is Alan Macdonald from Westinghouse Transient Analysis. During that time period the operator -- credit is taken for operator action to terminate the SI. Usually what happens is that you terminate SI prior to the pressurizer going water solid. However, post you have a swell of decay heat which causes the pressurizer to go water solid and that time is just a race to move to decay heat fast enough to make it so that you offset that swell.

MEMBER ABDEL-KHALIK: But the event is terminated by operator action.

MR. MACDONALD: Yes.

MEMBER ABDEL-KHALIK: Thank you.

MR. MIRANDA: As I said, this analysis was not accepted by the staff and the reason is that unless a plant is operating with block valves closed you wouldn't have a situation like this. And you will open the PORVS, and there will be water passing through the PORVs. And what we were looking for was some assurance that these PORVs if they open under water relief they'll recede. We don't have that, we don't know that unless they're qualified for water relief. And in most plants they're not. In TVA's

case they're not. So we asked for a new analysis.

MEMBER STETKAR: I'm sorry, you said in TVA's case they're not qualified for water relief?

MR. MIRANDA: Right. There are only six plants that have qualified PORVs. Watts Bar is not one of them.

MEMBER STETKAR: So during LTOPs if they have water relief they're not qualified?

MR. MIRANDA: Well, during LTOPs as I said it's a different set of conditions. It's lower pressure, lower temperatures.

MEMBER STETKAR: Not lower pressure.

MR. KOONTZ: Maybe I can help on that. Frank Koontz. When I mentioned earlier that the PORVs were not qualified that's for full pressure power type operation conditions. We do credit PORVs. We submitted information to the staff showing that they will work under LTOP conditions which is much lower temperatures and pressures.

MR. MIRANDA: So, we were getting analyses like this, along these lines where the safety valves are demonstrated not to open and the PORVs are, the PORVs are set aside as being valves that could be isolated. And we found that to be unacceptable and the reason was that if in the event that the PORV

should open under water relief and should stick open that by itself constitutes a small-break LOCA at the top of the pressurizer and that violates the acceptance criteria that prohibits a condition 2 event from developing into a condition 3 event. So if the operator is closing a block valve he's not mitigating an inadvertent SI actuation, a condition 2 event, he's mitigating a small-break LOCA, a condition 3 event which is evidence that the criterion has been violated.

So we wrote a RIS on that in 2005 basically saying don't send us analyses like this anymore. Show us that you meet the condition 2 acceptance criteria. And that was in 2005 and TVA submitted an analysis like this in 2008. So we went back to them and asked them for a new analysis. And after several rounds of RAIs we did get the new analysis and the results showed that there was at least 10 minutes available for operator action. So they were acceptable.

Boron dilution. We got analyses only in modes 1, 2 and 6. We were looking for analyses in all modes. And TVA at first tried to tell us about Generic Letter 85-05. It's a letter written by the staff in 1985 which basically said don't worry about

analyses in modes 3, 4 and 5. We don't consider it a safety risk in the sense that we don't want to be backfitting anyone. If you don't have analyses in modes 3, 4 and 5 you don't need to submit them because we don't think it's worth it. And that was addressed to operating plants. Except Watts Bar units were not operating in 1985 so we asked them to do the analyses and we haven't gotten them yet. This is an open issue.

But the two things we're looking for in all modes, especially in modes 3, 4 and 5 which are the shutdown modes, we want to see that the operator has sufficient time to terminate the dilution, 15 minutes, and that 15-minute time span has to begin from some indication, some reliable indication to the operator that there is a boron dilution going on. And the Westinghouse methodology that we received from Watts Bar was a set of analyses in modes 1, 2 and 6 where this time span, this time period 15 minutes began at the initiation of the event, not at the time of a reliable indication.

MEMBER ABDEL-KHALIK: Wouldn't the assumption that the 15-minute period begins at the initiation of the event be more conservative?

MR. MIRANDA: The time -- let me see. No,

because if you don't get an indication that would alert the operator that something is going on that boron dilution could continue until you reach criticality. And that could be anytime. If the operator doesn't know that he needs to do something he could reach criticality. The operator would never know it until it's too late.

MR. MILANO: Is your question, you know, the difference between the start time of initiation and start time of initiation based on the alarm? And I think what Sam, what the difference is is that -- is the way the staff is reviewing it it takes into account that there has been a certain period of time of dilution that's already occurred prior to the alarm, and then the operator has 10 minutes more, you know, where dilution could still be taking place until he terminates it. So you've got a longer time period where dilution is occurring if you -- and by the way the staff is reviewing it.

MR. MIRANDA: I think, in other words when the operator finally realizes there is a boron dilution going on there may be no time left, or very little time left.

MEMBER STETKAR: Depending on where the alarm is set.

MR. MIRANDA: Yes.

MEMBER ABDEL-KHALIK: And your assumption is that it will take the operator a minimum of 15 minutes to do it because that would be the only way to logically say that, assuming that time counting starts from the point of detection is the more conservative is if this 15 minutes is an assumption that this is the minimum time it would take the operator to do the job.

MR. MIRANDA: That's the way it works out, yes. That's the -- you call it an assumption, it's a ground rule. It's 15 minutes we have to have, yes. Right.

MEMBER ABDEL-KHALIK: It is an assumption.

MR. MIRANDA: Yes.

MEMBER ABDEL-KHALIK: Okay, thank you.

MR. MIRANDA: The steam line break. We had a lot of discussions concerning this.

MEMBER SKILLMAN: Would you please discuss what "too good" means in that context, please?

MR. MIRANDA: Yes, yes, I will do that. Steam line break is a condition 4 event and it's analyzed with and without offsite power. And the results in almost all cases for all plants, Westinghouse plants, is that the case with offsite

power will lead to a return to criticality. This is a steam line break occurring on hot zero power. The core returns to critical and generates power. And the power, the peak power level in a case with offsite power is always, always higher than the case without offsite power. And the reason is that without offsite power the reactor coolant pumps are tripped. The reactor coolant system flow is lower and therefore the primary to secondary side heat transfer rate is lower. So the cooldown that is initiated from the secondary side due to the steam break has less of an effect because the primary system flow rate is lower so that in the case without offsite power the return to critical and the power generation that results would go to a lower level. So for example, a 4-loop plant of the Watts Bar design might return to critical and produce, say, I don't know, 15 or 18 percent power with offsite power and only about 5 percent without offsite power.

The TVA results were reversed. The case without offsite power produced a higher power level, and that was not very high, it was only about 3 to 5 percent power. The case with offsite power produced a much lower power levels, less than 2 percent, so I questioned that. And the response was that, the case

without offsite power, because the heat transfer rate was not as high it caused a less severe depressurization in the reactor coolant system, and this depressurization did not extend to the accumulator setpoint. So there was no benefit of boron coming from the accumulators. Therefore, the core reached a higher power level. The case with offsite power produced a great depressurization. It caused the accumulators to inject so the core got more boron in that case.

So the natural question after that was well, show me a smaller steam line break case with offsite power, one that is too small to depressurize the reactor coolant system to the accumulator injection setpoint. I want to see a case without offsite power and without the accumulator boron. And the answer received was that all sizes will produce accumulator -- with power will produce accumulator injection which I couldn't believe. And Westinghouse provided some analyses.

MEMBER ABDEL-KHALIK: Excuse me. All sizes including inadvertent openings of secondary side valve?

MR. MIRANDA: All sizes. Even zero. Even zero, yes. So after several rounds of questions the

answer it turned out was that they were always getting accumulator injection for the with-power cases because of the auxiliary feedwater assumptions they were using. They were using very, very conservative flow rates for auxiliary feedwater, very high rates of auxiliary feedwater addition so they were cooling down the plant just with auxiliary feedwater. So a zero break size would cause accumulator injection.

MEMBER STETKAR: Does that mean every plant trip causes accumulator injection?

MR. MIRANDA: Well, according to those assumptions, yes. Yes, they were flooding the steam generators with aux feed.

MEMBER STETKAR: A lot of cold feedwater.

MR. MIRANDA: Yes, yes. So, we got a new analysis --

MEMBER ABDEL-KHALIK: But if that's the case it wouldn't make any difference whether the power, you have offsite power or you don't.

MR. MIRANDA: Well, you have the offsetting effect of the degraded heat transfer due to the lower flow. So you could have more heat being extracted from the secondary side but how that feeds back to the core under reduced flow conditions, it's not obvious. It just, there is -- you're increasing

the secondary side heat extraction, but how it translates to the core temperatures is not, there's not as much of a direct link due to the reduced RCS flow.

So that was one question I had. Another question was they analyzed one state point. The procedure for steam line break is to select state points from the transient and feed them through to a detailed core model, thermal hydraulic model to evaluate the DNB ratio. So they would take the power, temperature, pressure, boron concentration and so on at any given point and they would do a transfer of state points. And this is basically hundreds of state points but they select one, the one they think is going to be the most severe and they take that, they carry that through to a natural DNBR calculation. And that DNBR calculation should result in a DNBR that's greater than the limit which would be 1.3.

MEMBER ABDEL-KHALIK: So your primary concern was DNB?

MR. MIRANDA: DNB, yes. The steam line break, it's a condition 4 event but it meets the Westinghouse plants, it meets condition 2 criteria.

MEMBER ABDEL-KHALIK: So what was the peak containment pressure for this ice condenser

containment during a steam line break?

MR. MIRANDA: That's a different analysis. That is done at full power and it's designed to produce high temperature. It's a containment pressure response analysis where you try to dump as much steam into containment as possible. In this case you're trying to maximize the cooldown.

MEMBER ABDEL-KHALIK: What is the steam generator pressure at hot zero power?

MR. MIRANDA: At hot zero power the steam generator pressure is at its highest.

MEMBER ABDEL-KHALIK: Correct.

MR. MIRANDA: And it's about 1,100 psi.

MEMBER ABDEL-KHALIK: Correct. So if I had a steam line break inside containment at hot zero power at end of cycle wouldn't that produce the highest containment pressure?

MR. MIRANDA: No because if you have, you have the high pressure and you have the contents of the steam generator which are also pretty high. But if you do a case at full power you're generating power so that the steam --

MEMBER ABDEL-KHALIK: The reactor trips very, very quickly. The reactor trips very quickly in that --

MEMBER SIEBER: But you've got the decay heat level circuit.

MR. MIRANDA: Yes, you have decay heat. In the hot zero power case you assume there's no decay heat because you want to maximize the cooldown. So basically what you're doing for the containment pressure response case, you have the plant initially at full load, it trips, then you have the full decay heat that you need to remove and you're generating steam with that decay heat. And --

MEMBER ABDEL-KHALIK: So let me just ask the licensee the question. What is the peak containment pressure during a steam line break? Whether it is at full power or at hot zero power and in this case it would have to be end of cycle so that you can have the highest NTC and the highest decay heat.

MR. KOONTZ: This is Frank Koontz again. We'd have to check on the peak containment pressure. What I can say is that for the containment design what we worried about for pressure is the large-break LOCA because that's the one that generates the most mass energy release to the containment, generates the peak pressure.

MEMBER ABDEL-KHALIK: I understand, but

sometimes they are comparable.

MR. KOONTZ: Right. For the steam line break it turns out that what that generates is the highest temperatures in containment. They're much higher temperatures than for the large-break LOCA and they peak around 325 degrees to 327 degrees Fahrenheit. And for the steam line break although you get a lot of steam out there's not a lot of mass associated with that compared to the LOCA where you've generated all the primary side leak into containment. The ice does not fully melt out in a steam line break as it does in a large-break LOCA. So from the perspective of the containment design we don't melt as much ice for the steam line break but we do generate higher temperatures in the lower compartment. And for the LOCA we melt all the ice but we don't generate quite as high of temperatures in the lower compartment. And what Sam's concerned about is the event he was looking at is the quarter response, the return to power and all those effects that you get from over-cooling the water from the steam line break.

MEMBER ABDEL-KHALIK: Right.

MR. KOONTZ: We can look it up. I mean, I don't remember exactly what the --

MR. BRYAN: This is Bob Bryan. In the

design your first pressure peak, whether it's a steam line break or a LOCA is pretty much caused by the shoving all of the air from the lower compartment into the upper compartment. And that gives you about a psi. And so that's just basically a gas law equation. So even for moderately small steam line breaks you will essentially blow all of the air out of the lower compartment. So basically for all of these breaks except for very, very small ones you're going to see pressures in or about the 8 psi range. And as Frank said, since you've got total energy release is so much lower in a steam line break compared to LOCA you never melt the ice so that represents the peak pressure.

MEMBER ABDEL-KHALIK: Could you please give us definitive numbers to the peak containment pressure during the event?

MR. BRYAN: To contrast that the peak pressure for LOCA is around 12.5.

MEMBER ABDEL-KHALIK: Okay, thank you. Thanks. Now, are these calculations done at the moderator temperature coefficient that they give for a tech spec limit of, I guess I translate your units to -45 PCM per degree?

MR. MIRANDA: The core response steam break analyses which we were reviewing are conducted

at hot zero power, end of life conditions with the most negative NTC. And that's in order to generate the greatest reactivity excursion.

MEMBER ABDEL-KHALIK: Okay.

MR. MIRANDA: So, my first impressions in looking at the steam break analyses were that, first of all that this relationship between a steam break with offsite power versus a steam break without offsite power seemed to be reversed and that was attributed to the effect of the accumulator. And then also the magnitude of the return to power seemed to be rather low. And Westinghouse explained that that was because of their reactivity coefficients they were using. And they had been improving shall we say, improving since the time we first saw the Watts Bar results back in the '80s until today. So that the -- in similar plants they're also getting rather low returns to power.

And so what we did was during the second audit Westinghouse conducted a series of analyses in which they changed one reactivity coefficient at a time starting with the Doppler feedback and then going to the moderator temperature coefficient and so on until they reproduced the results I had seen earlier from the '80s. So that explains the effect of each

coefficient that was in use. And these coefficients that Westinghouse was using were documented and used in other plants of similar design.

MEMBER ABDEL-KHALIK: Now, you indicated earlier that, you know, you did sort of due diligence and found out that they are running the aux feedwater flow at fairly high value and that's the reason perhaps for this discrepancy in the result. What was the assumed aux feedwater flow and is that within the capability of the aux feedwater pumps?

MR. MIRANDA: They were, it's conservative. You'd have the cooldown, the maximum cooldown so what they were doing was using the maximum aux feed flow available, all pumps running and I believe they were all going to the faulted steam generator. So it's kind of an unrealistic situation.

MEMBER ABDEL-KHALIK: So they were assuming runout capacity for all aux feedwater pumps and all of that going to the faulted generator?

MR. MIRANDA: That's what I --

MEMBER ABDEL-KHALIK: Is that correct?

PARTICIPANT: That's correct. It's 2,842.

MEMBER ABDEL-KHALIK: Okay.

MR. MIRANDA: So in effect they were creating another accident in aux feed flow-induced

cooldown.

During the course of this review we -- there was a lot of reliance on the WCAP-9226 which was written in 1978 which was written in order to show that limiting cases were identified for Reg Guide 1.70 which requires limiting cases. So the WCAP-9226 did a series of -- reported a series of sensitivity studies, steam line breaks of different sizes and different assumptions including cases with and without offsite power. And they concluded from that WCAP that the largest steam break was also the limiting case.

But a lot of things have changed since 1978 and just to mention a few. In 1978 the flow measuring Venturi was located in the steam line and therefore it was possible to have a break upstream with a steam line which amounted to a 4.5 square foot break. And that was analyzed in WCAP-9226. Today Westinghouse plants don't have a flow Venturi steam line. It's located in the steam generator outlet nozzle so it's not possible to have a break upstream of that Venturi. And the maximum break that could occur in a Westinghouse plant is 1.4 square feet which is the area, the 16 inch flow area through the nozzles where the flow chokes. So, more than half of the cases analyzed 9226 were no longer applicable, they

were the large-break that doesn't exist anymore.

MEMBER ABDEL-KHALIK: No, let's go back to the sort of unreasonable assumption of too much aux feedwater flow. Regardless of whether you have the reactor coolant pumps running or not this assumption leads to a much more severe cooldown transient, is that correct?

MR. MIRANDA: Much more than I would expect under normal conditions, yes.

MEMBER ABDEL-KHALIK: Correct. So regardless of whether one is more severe than the other per your expectations you would expect that because the assumed transient is more severe in terms of the cooldown that if they were to do this correctly either, number one, the reactor would not return to power or the peak power would actually be less than what they calculated.

MR. MIRANDA: You mean if they were to reduce the aux feed flow to --

MEMBER ABDEL-KHALIK: Correct. To make it a less severe cooldown transient.

MR. MIRANDA: Yes. Right. They do that to produce a conservative analysis. Right. So if they were to use a smaller aux feed flow rate I would expect a, either a no return to criticality or a

smaller peak power level.

MEMBER ABDEL-KHALIK: So if that's the case why are you concerned and asking them to repeat the analysis?

MR. MIRANDA: I asked them to repeat the analysis to understand how they got the results they got because the other side, the other side of that question was why is the flow rate, why is the peak power level reached so small. It should have been much higher, especially with the higher aux feed flow. It should have been, I was expecting a peak power level in excess of 20 percent and they were showing only, I don't know, about 5 percent. So that part of it, the analyses they repeated to examine that part was due to the reactivity coefficients they were using. They were much improved coefficients compared to the ones they were using in the '80s.

MEMBER ABDEL-KHALIK: But nevertheless they have agreed to redo the analysis.

MR. MIRANDA: They did that. They did it during the audit, yes. And because, actually it was a series of analyses where they separated out each coefficient to see the effect of it.

MEMBER ABDEL-KHALIK: Okay.

MR. MIRANDA: So I was able to get from

the '80s results to the 2008 results.

MEMBER ABDEL-KHALIK: Thank you.

CHAIR RAY: You have this all written up somewhere I trust for historical purposes if we wind up having to re-resurrect this from five years?

MR. MIRANDA: Well, we do have an audit report.

CHAIR RAY: Yes, okay.

MR. MIRANDA: Another thing that changed, this is historical. Another thing that changed since WCAP-9226 was written was the boron injection tank. Plants in those days had a boron injection tank in the safety injection system containing 20,000 ppm boron which was injected into the core and then had a dramatic effect on the reactivity. That's been removed and now the concentration of boron in the safety injection water is only about 2,500 ppm.

So, it doesn't, the reactivity curves don't show, you can't tell by looking at the reactivity curves exactly when the safety injection water enters the core. It used to be that there would be a big drop-off. Now it just levels off.

And the end of the steam line break is not so much the time at which high concentration boron enters the core, it's more related toward when the

steam generator dries out, when the -- basically when the cooldown has proceeded to its logical end. And then the temperatures begin to level off and the reactivity excursion is ended and the core returns to sub-critical.

So the staff as a result of this particular review, it was the only review by the way that I've seen where these results were reversed. And it's traced back to the methods used that date to 1978. And we are, the staff is reviewing WCAP-9226 and chances are that it's not going to be accepted any longer for referencing in licensing applications because it's outdated. And the staff retains the right to do that when they approve a method or topical report. When things change the staff can withdraw its approval.

So as a result of all this all of the analyses we've seen with the exception of the boron dilution where we're still waiting for results, we've seen -- we're convinced that --

MEMBER ABDEL-KHALIK: Sorry, back to the comment you made about withdrawing approval of a licensing topical report. What code was used to do this analysis?

MR. MIRANDA: The code that was used to do

the Watts Bar analyses was the RETRAN code.

MEMBER ABDEL-KHALIK: The RETRAN.

MR. MIRANDA: RETRAN.

MEMBER ABDEL-KHALIK: LOFTRAN.

MR. MIRANDA: Was it LOFTRAN?

MEMBER ABDEL-KHALIK: LOFTRAN, that's almost 30 years old.

MR. MIRANDA: That's right, okay. You're using LOFTRAN. You usually use RETRAN. For this case you're using LOFTRAN and for the sensitivity studies at the audit it was also LOFTRAN. WCAP-9226, the studies that were done for that report in 1978 they used the MARVEL code.

MEMBER ABDEL-KHALIK: MARVEL.

MR. MIRANDA: And that code is no longer used, except by Mitsubishi. And you'll find MARVEL studies --

MEMBER ABDEL-KHALIK: So your withdrawing approval of that particular licensing topical report does not impact the staff's approval of LOFTRAN.

MR. MIRANDA: No, no, LOFTRAN is a valid code, so is RETRAN. So is MARVEL. It's just the way in which they were used for the steam line break analysis.

MEMBER ABDEL-KHALIK: Okay.

MR. MIRANDA: We found that some of the things that came up during the Unit 2 reviews would extend to Unit 1. So that's something that needs to be addressed, how Unit 1 is going to deal with the effects that were found in Unit 2. And as I said before, the steam break analysis methods have to be updated. The methods that Westinghouse is using today are not the same methods that were described in WCAP-9226. There are some things they no longer do and there are other things that they've added that they haven't reported.

MEMBER SKILLMAN: Does your second bullet point to deficiencies in the present analyzed condition of Unit 1?

MR. MIRANDA: Well, for example, the inadvertent SI actuation, both Units 1 and 2 have that, well, before the review started they had that analysis that looked at depressurizing safety valves and showing they wouldn't open. Well, the licensing basis as a result of this review for Unit 2 has a new analysis and so now we have two different licensing bases with two different analyses. And we would expect to see a similar change made to Unit 1 and that would be also in line with the RIS that was written in 2005. That RIS indicated that kind of analysis was

not acceptable and that applications by licensees even on unrelated topics would be reviewed with respect to the inadvertent SI actuation event and if necessary there would have to be a change. That's what the RIS said that would be reviewed.

MEMBER SKILLMAN: How is that handled in enforcement space for Unit 1?

MR. MIRANDA: Well, I don't know. I don't consider this to be a safety issue, I think it's a licensing issue. I don't think you're going to have a small-break LOCA tomorrow at one of these plants.

MEMBER SKILLMAN: Our business here, it poses a very interesting question when you take a newer unit and apply it to the licensing basis of the older unit. And then the analytical activities on the newer unit discover what could be a shortfall or an efficiency on the licensing basis of the old unit.

MR. MIRANDA: Yes.

MEMBER SKILLMAN: That seems like even though that's not ACRS's purview for Unit 2 that certainly raises a flag about what is going to be done on Unit 1.

MR. MIRANDA: Yes. Another example is that Unit 1 does not have the CVCS malfunction in its license. It's not in their FSAR, it needs to be added

to comply with Reg Guide 1.70.

CHAIR RAY: Well, let's not get into what's required to comply with the reg guide. Go ahead.

MR. MIRANDA: Well, that's it. Unless there are any further questions.

MEMBER STETKAR: Can I ask TVA a question? What is your, you refer to it as LTOPs. It's referred to as COMS, the low pressure setpoint on the PORVs. I've been searching for it here, I can't find it in the FSAR.

MR. KOONTZ: You mean where do they arm, the pressure that they harness?

MEMBER STETKAR: What is the arming pressure, do you know?

MR. KOONTZ: For Unit 1 it's 350. I think for Unit 2 it can be armed as low as I'm thinking it was 250.

MEMBER STETKAR: Well no, not the arming. What is the actual pressure, the opening pressure setpoint.

MR. KOONTZ: Oh, it's a variable. We'd have to look into it.

MEMBER STETKAR: Oh, it's variable as opposed to the temperature.

MR. KOONTZ: Yes.

MEMBER STETKAR: Okay.

MR. KOONTZ: It's in the pressure temperature limits report is where it's at.

MEMBER STETKAR: Okay.

MR. KOONTZ: PTLR they call them.

MEMBER STETKAR: Yes. We obviously don't have that. I was just trying to get a feel for where it's at.

MR. KOONTZ: I was trying to think, it may be in the --

MEMBER STETKAR: I can't find it in the FSAR. I've been sitting here trying to find it so I don't think it is. Okay, thanks.

CHAIR RAY: Okay. Well, any other comments or questions on the transient analysis presentation now that we've heard both from the TVA and the staff? Thank you, Sam. Okay, now --

MEMBER ABDEL-KHALIK: Thank you for accommodating us.

CHAIR RAY: Yes, appreciate that. Pat, we can either break for lunch now or we can take the region. I think we would prefer to break unless the region needs to go forward in which case we can accommodate that.

MR. MILANO: Bob has already indicated to us that he doesn't have a travel restriction that wouldn't prevent us from doing it this afternoon.

CHAIR RAY: All right. Then we will take a break for lunch and we'll resume at, in accordance with the schedule we'll resume at 1 o'clock.

(Whereupon, the above-entitled matter went off the record at 11:48 a.m. and resumed at 1:03 p.m.)

CHAIR RAY: We'll resume session and we'll begin with our scheduled report before the lunch break from Region II.

MR. POOLE: Okay. So the next portion of the presentation we'll go turn it over to Bob Haag to go over the status of the Region II construction inspection activities.

MR. HAAG: Good afternoon. As mentioned before my name is Bob Haag. I'm the branch chief from Region II with oversight for Watts Bar 2 construction activities. What I wanted to do was kind of give you the results of some of our recent inspection efforts and assessment efforts, then go over kind of the status of where we're at with implementing the inspection program. Our level of effort is the amount of inspection that we've been performing, kind of where the staff is as far as how many people have been

assigned to the project and inspecting at Watts Bar. And I was also going to spend a bit of time at the end of the presentation going over pre-op testing inspections and where we're at in our preparation phase.

So the first slide deals with the results of our inspection program. In previous presentations I had described how we were assessing performance for Watts Bar 2 construction project, and it's similar to the way we're looking at performance and assessing performance under the ROP. It's very structured, you know, at each quarter we'll look at performance at a mid-cycle. We look at it in a more formal manner at the end of cycle. We also look at it -- we've adopted that policy and that process.

So our last formal performance assessment was the 2011 mid-cycle review. And the overall results from that review was that we felt performance was at an acceptable level and that TVA's programs, processes and implementation were adequate for the given level of activities involving safety-related work.

I wanted to highlight three areas that we both discussed during our performance review which is an internal NRC review and that we highlighted to TVA

in our assessment results letter. The first area I wanted to highlight was a problem that we'd seen with implementing, their implementation of corrective action for some historical problems. And these were issues that had been identified back in the '80s time frame. Most of them were identified through TVA's rating of a condition, a construction deficiency report (CDR) and we were following up on those actions to make sure that they were properly implemented. And what we found were four examples of where TVA thought the corrective actions were complete. When we looked and pursued it we identified that corrective actions had not been adequate. They resulted in a severity level IV violation that we issued. And our concern there was based on the number of historical issues that TVA has to fix, again that have been identified during regional construction and some of the more recent construction activities is the fact that they need to be diligent in making sure those corrective actions are complete. So we've iterated that to them, we've discussed that in some public meetings and clearly we're following up during our review of other historical --

MEMBER ABDEL-KHALIK: Can you give us examples of significant historical issues that fall in

that category?

MR. HAAG: Not significant, none of these were significant as far as the typical, you know, mind frame of what a significant issue is. The ones that come to mind as far as these four examples, a couple of them dealt with welds, inadequate welds that either they needed to go back and assess as far as were the welds adequate or they had already identified they needed to do some repairs and hadn't done the repairs. None of them, though, I would characterize as far as significant.

MEMBER ABDEL-KHALIK: Okay, thank you.

MR. HAAG: The second area I wanted to highlight was the ongoing saga with the Heinemann circuit breakers and the seismic qualification for those breakers. These are the molded case, 120 volt circuit breakers and during a previous inspection we had identified a problem with the seismic qualification. These are new breakers, replacement breakers that they're using. And what we highlighted in our letter was just the length of resolution for this and the fact that it hadn't been resolved. It's been going on for almost two years as far as once we identified it TVA's initial resolution or initial response to us, the back and forth. Where it stands

right now is we wrote, the region wrote a TIA request for information for the technical branch and NRR to look into it and they've had a series of public meetings where the TVA staff presented to the NRR staff their position and where they're at with the qualification effort. It's still yet to be resolved.

The third item I wanted to mention was the fact that during this review, the mid-cycle review we went and looked at crosscutting aspects. We follow a very similar process for our construction inspections as we do in the ROP. If we have a finding we'll look to see if there are crosscutting aspects and if the numbers reach a certain threshold we're questioning whether there is a substantive crosscutting issue.

During an earlier assessment back in I think this was the end of cycle review for 2010 they had satisfied the criteria in our manual chapter for number of similar crosscutting aspects that would give you a substantive crosscutting issue. But at that time we recognized that two of the four issues were very recent and we had yet to be able to really assess TVA's corrective action. So we delayed deliberation to say whether there was a substantive crosscutting issue. We went back and we reviewed that in our 2011 mid-cycle review and determined there was not a

substantive crosscutting issue. So that kind of blows the book on that issue.

MEMBER ABDEL-KHALIK: Because of corrective actions?

MR. HAAG: Because of the corrective actions and the fact that when we had an additional six months of review time the numbers actually went down to less than what the threshold would have been in manual chapter as far as reaching a certain threshold.

The other points I discuss from our mid-cycle review is that when we looked over at the period of time, and typically you always look back for a 12-month period of time, there have been 12 severity level 4 violations identified during that period and they had a variety of subjects, design control, corrective action, I mentioned one of the corrective action issues, procurement and procedural compliance. I would highlight, you know, there were no escalated enforcement or severity level penalties, civil penalties and that's one of the criteria in the manual chapter as part of our assessment process where if there were escalated enforcement or civil penalties we would look at increasing our inspection effort.

CHAIR RAY: Bob, does this matter of who's

got the keys that you heard discussed earlier today, I think you were here for it.

MR. HAAG: Yes.

CHAIR RAY: Just tell us how that affects you if at all.

MR. HAAG: As far as the change recently and how TVA is interacting with their contractor?

CHAIR RAY: Well, you could express it that way but basically we're looking at a period of time here which has included both modes of operating going way back. I don't know if you were there or not. We talked about how because of the legacy of responsibility having shifted to a portion of it at Bechtel and some that is still there that used to be with TVA and now part of it, and I'm not trying to differentiate here between quality affecting activities and management responsibilities. I understand the difference between them, but I'm really asking the question how if at all, and a comment was made about everybody wears the same color hat now so implying that it's a single integrated team, no differentiation between TVA and Bechtel is the way I took that. The question really is are you affected by that at all one way or the other.

MR. HAAG: No.

CHAIR RAY: Does it make any difference at all?

MR. HAAG: The answer is no. I mean, when I look at how we were conducting our inspections, interfacing with either TVA or the workers, it has changed very little over the past, well, since the project has taken place. I mean, TVA has always had an active role, contractually things may have changed but they've always had an active role in the project from my perspective. And they continue to maintain that.

CHAIR RAY: Okay. Well, I noticed design control is an issue up there and of course design control moved from TVA to Bechtel and I guess it's still with Bechtel even under this modified.

MR. HAAG: Clearly engineering efforts are being done by Bechtel engineers.

CHAIR RAY: Okay.

MEMBER SKILLMAN: Bob, my question is with this inadequate corrective action for several items that are legacy, years old, what confidence do you have in TVA's present QA program and particularly their energy around criterion 16 to identify items and to pursue them until they are fixed.

MR. HAAG: The way I'd respond to that is

the current corrective action program while clearly has to envelop these legacy issues they're somewhat separate. And we look at the current corrective action program under the same tools that we do the ROP. We do PI&R inspections, we typically look at, you know, when problems are identified do they correctly identify it, do they capture all aspects of them and then we'll look at the corrective action. And we do, we've been doing annual PI&R inspections and we've seen some problems there and we've seen some improvements and the typical corrective action program and what's implemented right now at the station.

These historical issues, the identification was not a problem. You know, the identification had been done years ago. It really was the follow-up to the issue and ensuring that, you know, if you had some belief that corrective action was done back in the '80s and now you needed to confirm that, well you need to have some clear evidence that those actions were done, not relying on somewhat anecdotal information. So it was more of that where they, the level of pursuit of the corrective actions, that's where we saw some breakdowns at least in these four examples.

Our confidence going forward? It really

has to be built. I mean, we're going to, we've identified those historical issues that we have on our inspection plate and we're going to look at those things so clearly we're not just sampling those. There's, you know, a set number of historical issues we're going to inspect. So we'll be verifying the corrective action for those. And again, through the discussions we've had, management discussions and you know, in emphasizing to TVA, the importance that they understand what the corrective actions are and that they do due diligence, making sure it gets done.

MEMBER SKILLMAN: Have you heard with the same energy that TVA leadership speaks of building a safe work environment, the same energy around having quality workmanship and a quality product for what they are doing at Watts Bar 2?

MR. HAAG: I mean, I would say that was never a problem. It was these examples where we found shortcomings. And you know, we've looked at TVA's corrective actions for the severity level 16 violation in that, you know. Obviously the individual items had to go back and be corrected but they also needed to step back and look at and ask themselves why didn't we pick up on this. Why did we think the problem was resolved when it really wasn't. And we've pursued

that and we're looking at that. Yes, we have some confidence that they have made some changes and have improved their process but again, until we get, you know, additional examples where we've looked at their closure packages, where we've looked at their corrective actions and have some confidence, you know, it's still an open issue.

MEMBER SKILLMAN: Thank you.

MEMBER ABDEL-KHALIK: I had a question about design control. Are there any concerns about updating design drawings in a timely fashion to correctly reflect the as-built condition?

MR. HAAG: I'm not aware of specific examples or concerns related to that, you know, updating their drawings, making sure that the design you know didn't fit what they thought it did, that when they make a change that they clearly update all the design documents. I don't think we've seen problems there. The design control, it's typically been, you know, classic criterion 3 violation where they didn't properly translate the design maybe into a working document, or you know, the product that they had in the plant, that was more the examples that we've seen as far as design control.

MEMBER ABDEL-KHALIK: Could you say that

again, please?

MR. HAAG: The criterion 3 where you have, the plant is designed. You have the design basis, whether it's a calculation or an analysis, and then transcribing that to your field instructions, your work packages for actually building the plant. That's where we've seen some of the disconnects. Again, these would have been at a severity level 4 level so they weren't necessarily that significant themselves.

MEMBER ABDEL-KHALIK: Okay, all right. Thank you.

MR. HAAG: So the next slide I wanted to use was to kind of give you a sense of the level of effort that we're expending for the construction inspections. For 2011 we spent over 17,000 of related hours involving inspection. Now those are all not direct inspection effort. Those are some of the hours that the inspectors and the folks who work in the region, who work for me, you know, managing the project. But a large number of that is inspection effort, inspectors actually out at the plant, out there looking at construction, looking at records. That was an increase from the previous year of almost 4,000 hours. And when we look at our scheduled inspections and what's left to be done we think it's

going to pretty much stay at that level of 17,000 hours which is a huge effort. When you convert that to FTE I mean it's a significant effort.

We're planning to continue the four resident inspectors, staffing at four inspectors onsite. We've had success in being able to look at areas that we wanted to, especially on those things where the schedule isn't as firm as you might necessarily would like as far as predictability and being able to send the regional inspector. So having someone out there on a full-time basis clearly alleviates that problem. They're there always and you know, if there's a change in schedule they can look at something else and be ready to look at the particular area that you're interested in.

As far as effort besides the four resident inspectors, when I went back and I counted up over the past year as far as how many inspectors you can see the number, 41 inspectors. I think that's pretty impressive as far as folks we either had from the region, some of those are contractors. We had a couple of inspections where we had contractor inspectors but 41 other individuals, you know, have actually been, you know, having eyes on construction activities and doing inspections.

As far as the regional complement and this is still within my branch we've increased the numbers. We have four people who work for me on a full-time basis on the project and that's an increase from we had two before back in 2010. And this previous year we added a team leader and a senior project manager to my branch.

Another initiative I wanted to talk about was our periodic public meetings. Our regional administrator has an interest in maintaining ongoing dialogue and allowance for the public to understand where the project is so he's asked us to conduct periodic meetings as necessary to set the time frame. He just wants us to ensure the local public has the ability to understand where the project is from an inspection standpoint, understand any of the issues that may be going on between NRC and TVA, ask questions and comments. So we're initiating those.

And we're taking credit for several different initiatives. We have an end of cycle meeting as part of the process and I'm including that as the ability to get out and tell the public what we're doing, let them ask questions, provide comments. So in total we had four public meetings out at the site in the local area at different venues in which

the public had an opportunity to, again, hear our inspection effort, what we're doing, any issues that are going on between TVA and the NRC and then ask comments and questions.

MEMBER SKILLMAN: Bob, please tell us what the mood is when you meet with the public.

MR. HAAG: It's varied. You know, none of the meetings have had a huge turnout. I'd say typically we may get, you know, between 20, 25, 30 members of the public and it's varied. We have, there are several individuals who are opposed to the project and they're routine attendance. We also get quite a bit of turnout from local officials who are supporting the project and they want to just voice their continued support for the project.

MEMBER SKILLMAN: Thank you.

MR. HAAG: So it does vary.

MEMBER SKILLMAN: Thank you.

MR. HAAG: So the status of where we're at in implementing the inspection program. During a previous briefing I had described kind of how we developed the inspection program for Watts Bar Unit 2 and it is unique because the history and the time frame from when they did the initial construction to where they're at right now, we had a -- we're doing

more than just typically what was done in earlier plants. Clearly the NRC has a program for inspecting construction. It's managed at 25.12, pre-op is 25.13, start is 25.14 but we're doing more than that, you know. So we went back, and again I don't want to go over all that, but we've looked in these different areas. And we ended up with over 500 unique inspection items that we're doing for Watts Bar Unit 2 and we've got those loaded into an access database where we're tracking. Whenever we do an inspection we'll track it and we'll close it out. So in the end we're going to be able to say we've completed the inspection program. To date we've closed a little over 150 of the items so there's still quite a few left to be done.

A large majority of the remaining items we have looked at one way or another and we've documented that inspection in a report. There's just either a few things we want to continue to follow up on and close out. Some of them we haven't even looked at at all but a large majority of the remaining items we have spent some inspection on. And you know again, there's just a piece that we need to look at to be able to say we're finally complete.

We've completed inspection of seven of the

corrective action programs, special programs. Those were the get well programs that TVA initiated to deal with the problems from the early construction that was done back in the 1980s. A couple of those programs are broken out into sub-issues and we've closed eight of those sub-issues. So there's still quite a bit of work left to do there, but again I would say the large majority of the CAPs and SPs we have inspected to some degree and you know, we understand what's left to be done and we're just either waiting on the construction to be finished or our ability to get up there and look at these issues.

MEMBER STETKAR: Bob, are you, you know, you mentioned your resource estimates for FY 2012 on the order of about 17,000 person hours. Given the fact that at least according to this slide, now recognizing that you're in progress on several of those, but this is, what, 30 percent complete roughly?

MR. HAAG: Just based on --

MEMBER STETKAR: I have no idea what TVA's new schedule will look like but are you quickly going to become resource-constrained or do you think that you're okay?

MR. HAAG: We think we're okay and it's more than just, you know, just a hunch. You know,

what we've done for all of the IPS items, we've estimated the level of inspection by number of hours and we routinely track that as far as where are we at, percentage complete, what's left to be done, when are you going to inspect it. We've had a recent initiative where we want to get the remaining inspections loaded into our Primavera construction inspection schedule. We're pretty successful on that. What's the uncertainty part, and that's the last bullet right here, is the corresponding construction activities. What we're trying to do, and it's similar to the effort that they're doing for the Part 52 plants is to take your construction inspection effort, whatever you want to look at, whether it's a weld, the installation of a hanger, whatever, tie that to the construction schedule from the utility, align the line time. And when they update their schedule our inspection schedule is also updated. We've had moderate success in doing that. It's a work in progress. I mean, it sounds like an easy process but it's not because, you know, the way they code items in their construction schedule sometimes it's difficult for us to be able to link our inspections to that. But again, you know, we're working on that. As part of the fact that we're also, CCI is also doing the

Part 52 construction and they're much more sophisticated in that effort. You know, we're taking advantage of the people who have that expertise to be able to help us out in the Watts Bar 2 project. Next slide.

So the last thing I wanted to do was kind of give you an idea of where we're at with the pre-operational testing inspections. I mentioned earlier we added a position to my branch. It's a team leader and his focus and his charge really has been looking at the 25.13 inspection program, kind of defining that, what do we want to do, coming up with the resource estimates, interfacing with TVA, what does their schedule show for system turnover, when the testing is going to be done and make sure we're ready for that. And we're having success in at least the initial scoping effort.

Manual Chapter 25.13 has mandatory tests, tests that have to be witnessed. These are the larger tests, the containment integrated leak rate test, hot functional test, RPS. Then it also has the primal system tests. Those are, you know, it lists over 20 different systems and you can pick and choose which systems you want to spend your inspection effort on to be able to look at both the test procedure, test

witnessing and records reviews. So we've gone through and we've selected the systems that we want to focus on and we've assigned inspectors, lead inspectors for all the mandatory and the primal tests. Our challenge now is to define the remaining inspection support group that's going to be needed because one person certainly can't look at many of these tests. They're involved and you may need, you know, three or four people, you know, back shift coverage and things like that. So what we're looking at right now is coming up with the resources that are needed, figuring out who in the region or even outside the region can provide those inspections. We're also looking at possibly having contract inspectors to assist us in that.

The other part of 25.13 is the operational preparedness inspections. Those are the areas, the traditional support areas. Management controls the procedures and I gave you some examples up there, radiation protection, chemistry, security, fire protection. We're taking a little different approach there. If you spend any time looking at those inspections and the way the program is defined the procedures have not been updated since they were issued and used back in the '70s and '80s, maybe early '90s. So you know, we've questioned is there a need

to do all those inspections as currently written. We think the answer is no so we're going through and doing a review to understand what's required for the inspection, factor in related inspections that may have been done recently under the ROP or other related inspection areas and come up with a clear understanding of what's needed for Watts Bar Unit 2 given its, you know, situation, the fact that many of these programs have been established and have been in use for Watts Bar Unit 1. We've been inspecting them over a number of years so what do we need to look at. Do we need to look at program inspections or do we need to look at, you know, implementation and has TVA captured, you know, what needs to be added to the program to cover Unit 2. We think that's the answer, but again we need to go back, define those, come up with some recommendations, make sure the program office, the NRR branches who have responsibility for those areas are in agreement with that and then kind of lay out our inspections there. So that was what I wanted to present to you as far as the inspection program.

MEMBER BROWN: Can I ask a question?

MR. HAAG: Sure.

MEMBER BROWN: You talked about, and you

have a list of access, I guess it's a database for stuff and there are, I don't know, there's a hundred and something, 120, 130 open items that are covered in the SSER where Region II is identified as the lead person or lead organization for resolving those, confirmatory and otherwise. Are those in your --

MR. HAAG: Yes, they are.

MEMBER BROWN: -- database also?

MR. HAAG: Yes.

MEMBER BROWN: The other thing I noticed in here was that there's a number of combinations of Region II NSIR items all dealing with emergency facilities, accident control, whatever, for the site. Nothing in there relative to the cybersecurity issues relative to the new rule 73.54. How is that being addressed in terms of your long-term confirmation of that the integrating of that particular issue? I seem to remember we had a previous full meeting on cybersecurity stuff and they explained what they were doing. All I'm trying to do is figure out how, I don't see anything being set up to go cover that. Or at least it's not listed.

MR. HAAG: And it's not included in that access database mainly because the temporary instruction that is going to be written to cover the

inspection effort has not been finalized. It's still in draft.

MEMBER BROWN: Who's doing that, headquarters or you?

MR. HAAG: NSIR is doing that. The region has been involved, there is a point of contact in the region, not in our division but the Division of Reactor Safety who will be doing the inspections at the operating site. He's also been involved in it as far as planning for Watts Bar Unit 2 because that will be one of the first plants that actually gets this inspection. So that's a point of contact, you know, from a continuous standpoint, you know. They've been involved in it, they will be involved in it, not just for construction activities but also for the operating plants. We will put, once that temporary instruction comes out it will get added to the IP&S database so we make sure we track that and we've completed it before we say all our construction inspections are done.

MEMBER BROWN: I don't know, I'm just, I'm winging it right now, okay? I'd really like to hear at a later date when that's, I think we should hear at a later date how that's being executed. You know, what does it look like, what do you all intend to do.

MR. HAAG: Yes.

MEMBER BROWN: In other words, how is that getting passed down, what's the temporary instruction say, how will you all execute that and what are the key critical areas which you intend to go pull the string on to ensure that we've isolated the plant and the items of interest from external hacking to put it bluntly. So I'd like to have that on the -- Harold, if you don't mind I'd like to have that discussion at some point from an inspection standpoint when it's available.

CHAIR RAY: Well, yes. As far as this process that we're engaged in here now of course it's leading up to a full recommendation and a full committee letter or perhaps more than one letter and we can discuss at that time whether to put something in the letter pertaining to what you're --

MEMBER BROWN: No, I just wanted to have some detail instead of waiting until the eleventh hour. I'd just like to have some idea of where they're going and how you intend to do that before we get to that point.

CHAIR RAY: Oh, I thought you wanted something more than just some additional information.

MEMBER BROWN: At one of the other meetings I'd like to have --

CHAIR RAY: Let me ask Justin here. We need to have some tracking of this between yourself and Girija so that Charlie or I can ask when are we going to get any more information about this inspection procedure.

MR. POOLE: Sure.

CHAIR RAY: And we're not going to, like I say, if nothing is available by the time we need to wrap this process up we can make a note of it at that time.

MR. MILANO: I'd like to make one comment.

CHAIR RAY: Sure, Pat.

MR. MILANO: One of the other things that we're going to do in this process is working with NSIR they are going to do a pilot audit at Watts Bar and that's not an audit type of inspection out there. What they're going to do is after the temporary instruction is prepare. They're going to take it to Watts Bar and look at its ability to be implemented. And it'll be sort of like a tabletop review. They'll go through it and say, you know, can this step actually be accomplished or do they need to adjust the focus or the direction in it to accomplish the objective that they want. So that audit right now we're looking at sometime late spring but it's still,

it's not fixed. It's all predicated as we've indicated on the initial development of the temporary instruction.

MEMBER BROWN: I'm just not sure what the instruction is going to say. I'd like to have some idea what's in it, what it's intended to accomplish. What an instruction does, is it just to make sure that the plant comes out like you want it to be or is it something that somebody's going to do every three months for the next 30 or 40 years, or what is it? I mean, I just, I don't even know what this instruction is supposed to accomplish. That would be a nice thing to know also.

MR. MILANO: The reason why I was bringing that up was it's probably, timing-wise it's probably best to, if you do want to hear something about it is after the audit is done and it's adjusted accordingly --

MEMBER BROWN: That's fine, I'm not pointing at any, tomorrow, or something. I'd just like to have, before we close out and we're ready to, you know, make a full understanding of what we think we've got we ought to have some idea what's going on there, that's all.

MR. SHUKLA: Mr. Chairman, there is only

one subcommittee meeting between and the full committee meeting remaining, so.

CHAIR RAY: Well, that may or may not be the case, we'll see. But in any event as Charlie said I'm not trying to change whatever the present schedule is, I just don't want to lose track of this item. If we can get the information before we're done and resolve it so that it goes away I think that's in everybody's interest. If not.

MEMBER BROWN: I have one other once we're finished with this.

CHAIR RAY: That's fine.

MEMBER BROWN: A couple of the action items also still have to deal with the communications between the Eagle 21 and the integrated computer system, the site, this large site integrated computer system. And they have a nice explanation of what this is supposed to be, you know, a configuration and how it was supposed to be hard-wired and all this other kind of stuff. You guys are down as the responsible action party to resolve this and make sure it comes out looking like that. And I guess I'd like, I presume you're going to be recommending that it be closed or not closed. Two of the items, let's see, one of the items associated with this is a

confirmatory item, the other one is an open item but you were still down as the action party for both of those. I guess I'd like to, because of the delicate nature of that whole one-way communication, you know, does it get configured the way it's supposed to, how are you going to check it, what are the resources you have to do that and how is it made such that it can't be, you can, the configuration control for that area which is kind of open.

MR. HAAG: So you'd like to have a presentation once we finish that inspection, give you the results?

MEMBER BROWN: Yes, that sounds like a short item, 5 or 6 minutes, 10 minutes, whatever it is. It's not rocket science, it's a matter of what's it look like in reality as opposed to the PowerPoint slide and explanation. That's something a little bit more to amplify again what's in the SSER to make it clear.

MR. HAAG: As I mentioned earlier we have included all those Appendix HH items that have Region II inspection portion, we have those included in IP&S and we've got an individual inspector assigned to all of that appendix items. So there is someone who is assigned to it. I can't tell you right now how far in

this case it's a female, how far she is in looking at it but we've got --

MEMBER BROWN: I'm not asking for that right now. Just, it's item 63 and 93 I believe. So thanks to Harold reminding me.

CHAIR RAY: Appendix HH.

MEMBER BROWN: Yes, Appendix HH in the latest SSER. The details are in SSER 23.

MR. HAAG: Sure. Okay.

MEMBER BROWN: Okay?

MEMBER SKILLMAN: Bob, I'd like to ask another question, please. What's interesting about Watts Bar 1 and 2 is the number of years between Unit 1 having come online and when Unit 2 will come online. And you've identified a number of programs here that are essential for the health of the unit rad pro, chemistry, security, fire protection, but there are more, configuration control, configuration management, design control. And my presumption is that by and large Unit 2, Watts Bar 2 will either adopt or be adopted by the Unit 1 procedures. And that leads me to wonder are there weaknesses in the Unit 1 procedures that need to be resolved before the integration of Watts Bar 2 is pulled into applicability for those procedures. In other words,

are there existing weaknesses today that really need attention so that when Watts Bar 2 is adopted that the program is healthy for both? Have you given any consideration to that, please?

MR. HAAG: I'd answer that by saying the people who will be doing that portion of the 25.13 inspections are the same organizations within Region II who have been doing the inspections on the Unit 1 programs. For example, the radiation protection. You know, the ROP clearly has baseline inspections that you do on an annual and a biannual, you know, period. We'll be having that same branch perform the inspections on Unit 2 that once we define what inspections need to be done they'll be doing those inspections. So they would have the best insight from a regulatory standpoint as far as where are some of the problem areas that have been identified with the Unit 1 programs if they exist and how are those, if it's a shortcoming or, you know, a marginal program how is that being addressed now because there's two units that that program has to support. So I mean, I think that's the best answer I'm going to be able to give you in that, you know, we have that consistency both from an understanding of where the problems are and also, you know, history on, you know, where do I

need to look, where should I be spending my time because of insights from previous inspections.

MEMBER SKILLMAN: Harold, do you consider that something worth talking about at a later point? I'm thinking about a lot of the work that I've done where I've found that the organization knew it had problems but didn't do anything and a year or two passed and now two units were in trouble. Here's a case where there's really a time constant that is introduced.

CHAIR RAY: Well, let's talk about it at the end, Dick. I'm not inclined to think that it's something we should create an action item about.

MEMBER SKILLMAN: Okay, thank you. Bob, thank you.

MR. POOLE: Okay. Thanks. The next part of the presentation is to go over the status of the licensing activities.

Okay, this slide shows based on the staff's review over the past two years or so and asking RAI questions and writing up their SE evaluations. TVA has had to make numerous amendments to their FSAR. The current version of the Watts Bar 2 FSAR is at Amendment 107. The next bullet there is to show that over the --

MEMBER STETKAR: Is that -- that's been amended?

MR. POOLE: Yes. Yes, it was. The next bullet there is to show that over the past five supplements to the safety report a large chunk of the review, the safety review has been completed and having gone before you guys today most of them have at least been discussed in front of the committee. The major areas that we have remaining is fire protection which we intend to talk in April and then the closure of the open items in the SER. And then I'll also point out, it probably should have been a bullet on here too, was the discussion we had last time on hydrology and the maximum flood level.

MEMBER STETKAR: For sure.

MR. POOLE: Okay. So as has been pointed out a few times already both in the introduction and TVA had a slide in their presentation and we've heard from some of the members here there's been a number of questions on how do we handle the open items. So we provided a slide here today just to go over some of the numbers, how we break them down and then Chairman as you mentioned we would love to hear at some point, you know, which ones, go over at some point which ones you guys are most interested in.

CHAIR RAY: Yes, I've gone over them myself. We have hard copies for those who want to use same but it looks to me like we'll have time that we can refer to that today and just go over the open items to see if any numbers have particular ones that are open at this time that we think warrant further discussion with the subcommittee or potentially full committee. But you tell me when you would like us to do that.

MR. POOLE: Sure. Let me run through this slide and then we can talk about that. So as the first bullet says there was 124 open items that were written into the different supplements of the Safety Evaluation Report. Just to avoid confusion there was, you know, looking at Table HH I believe the final number on there is actually 139. The reason for the discrepancy is that in preparing the different supplemental SERs there were drafts, open items originally created and then for whatever reason never ended up getting published. They were either resolved prior to publishing or were delayed until a further publication. So there were some numbers that were never used.

As TVA pointed out before, to date as of SER 25 we've closed 41 of those 24 which means that

there's a total of 83 that remain open. We show in this slide that we break those down into essentially two categories, the items requiring NRC confirmation of which there are 43, and then items which require additional NRC evaluation which there are 40. Items that require confirmation essentially were created when the staff was provided sufficient information in order for them to make a finding of reasonable assurance. We needed confirmation, needed some sort of confirmation from the applicant to complete a follow-up action. This action could have been satisfactory testing, installation of equipment, or it could be a submittal of a report or a safety FSAR update. So given that, the closure of these confirmatory items can be accomplished either by regional inspection or a submittal to the headquarters staff.

For items requiring a submittal to headquarters staff the staff will verify that the information submitted is what was expected in order for the item to be closed. A very typical example of this is when during the review the staff required additional information and requested via an RAI. TVA provided the response and in reviewing the response staff felt that the information provided was important

enough to require an update to the FSAR. In many of these RAI responses TVA actually provided draft versions or pages of what they intended to update the FSAR to look like which allowed the staff to review at the same time as they're reviewing the technical information. So these truly are just a check of getting the same information that was already sent in, and then the staff just wanting to verify that it gets put into their FSAR to remain as part --

CHAIR RAY: We understand, I think. That's fine.

MR. POOLE: Okay. And then the other part of that is -- so because it's just a check, a confirmation there's no evaluation done in the Supplemental Safety Evaluation Report. It's marked off in Appendix HH and the submitted document is referenced in the table. This is also done similarly for inspection items, confirmatory items that are closed via inspection. There's no evaluation written in the SER and its update of the table pointing to the evaluation done by the region and their inspection report.

And then the items that require additional evaluation which are essentially the true open items, these were written because the staff required further

information from the applicant in order to complete its review. Upon receipt of the information the staff can finish its evaluation and document it appropriately in the next, in a further supplement to the Safety Evaluation Report. Our goal is to close as many if not all of these by the April subcommittee.

CHAIR RAY: Okay, well, tell you what, Justin. You probably have staff people standing by here that are intending to participate in these scheduled items of staff presentation. Why don't we stop the review of open items here now. I think we understand the difference between confirmatory items and other open items.

MR. POOLE: Okay.

CHAIR RAY: And so that we can let these people get back to productive work. Let's do the staff presentations that are on the schedule now. We will have a break perhaps after the first one given what time it is now. But finish them up and then at the end we'll be able to go through the open items table and give an indication to you and the applicant which items warrant consideration for the next, or if there are other subcommittee meetings in addition to the next one, future subcommittee meetings.

MR. POOLE: Okay.

CHAIR RAY: Can we do it that way?

MR. POOLE: Yes, that's fine.

CHAIR RAY: That way it lets the staff get back to their business. So, with that you take over and let's go through the items where there are staff presentations yet to do.

MR. POOLE: Okay. While they're making their way up to the table here I'll just point out, the next slide was just to say that before the -- their presentations are based on previous to Supplement 24 and 25. These were the dates. Okay. The next part of the presentation that we'll go over is the status of radiation protection. The reviewer for this portion was Mr. Roger Pedersen. I'll now turn it over to him.

CHAIR RAY: All right, Roger.

MR. PEDERSEN: Good afternoon.

CHAIR RAY: Good afternoon.

MR. PEDERSEN: I'm a senior health physicist in the Office of Nuclear Reactor Regulation. I reviewed Amendments 92 through 104 in terms of how those changes related to radiation protection both the occupational radiation protection in Chapter 12 of the FSAR as well as public radiation protection in terms of radiological effluents, both liquid and gaseous

effluents that's contained in Chapter 11 of the FSAR.

TVA made several changes to Chapter 12 in terms of occupational radiation protection design features. The list that I have here are some of the more notable. I didn't provide an exhaustive list of all the changes that were made. And of these six changes only the third bullet there in that last bullet resulted in a situation in which the initial change was unacceptable to the staff and we had to go back through the RAI process and resolve those issues. But let me run through them real quickly here.

There were a number of changes to the source terms that were identified in the FSAR. The most notable is the containment airborne estimates. TVA had identified an error in their previous calculation so they corrected that. It did not result in a significant change. It did not change the, even though the airborne estimate in the upper containment and lower containment changed it did not change whether they were considered an airborne area requiring controlled access or not. So it had no impact on our previous analysis.

There were a number of changes in plant radiation monitoring. Again, the most notable of those were the area airborne radiation monitors in the

aux building. Previously the FSAR described a fixed system of airborne monitoring. TVA had revised the FSAR consistent with how Unit 1 is being operated and that in the aux building which is pretty much common to both plants they have four portable monitors that provide four channels of airborne monitoring that are comparable to the fixed monitors that were previously described there. They alarm locally, they alarm --

CHAIR RAY: Was this a 50.59 change for Unit 1 or what?

MR. PEDERSEN: I would imagine so.

MR. BRYAN: This is Bob Bryan. Yes, it was.

CHAIR RAY: Okay.

MR. PEDERSEN: In addition to that there was a change in the description of the calibration frequencies and the channel operability tests. I'll get back to the position that we negotiated. There was a significant change in the description of the HP support facilities. The original FSAR had layout drawings depicting things like whole body counters and dosimetry and respiratory protection issues. Those layout drawings were removed from the FSAR. In lieu of replacing those drawings I accepted a detailed description of the facilities and the commitment out

of the applicant that they're adequately sized for two-unit operation which of course will be a subject of follow-up inspection activities.

The applicant also changed, made some changes to their dose assessment both the collective dose assessment, the annual dose that they expect to operate the plant and the dose assessment for vital area access. That's the dose to operators that have to access the plant during accident conditions to operate vital equipment to mitigate the course of the accident. It's TMI Lessons Learned item 0737-2B2. And that last item is actually one of the open items. Most of the RAIs that I had with these issues and the other issues were clarification issues asking for the applicant to clarify the basis for the change. And so they have clarified the basis for the change with the vital area access, they just haven't documented that in the FSAR yet. That's I believe the only open item left in the open item list.

And then the last item, again that was one of the ones that ended up as not acceptable to the staff, was an issue about RPM qualifications. The previous FSAR had a fairly clear commitment to the regulatory guidance in our Reg Guide 1.8 1978 in terms of what the qualifications are for the radiation

protection manager. That was removed. The response that I got to my RAI was not clear. It actually precipitated a review of the current procedure on qualifications. And one of the two issues besides the number of years of operating experience, one of the other issues that I brought up was whether there was a clear criteria as to how long someone who does not meet the qualifications could act as the RPM. It turned out that their procedure wasn't adequate to cover that to ensure the way they did things would be consistent with the Reg Guide 1.8. So I believe that generated a corrective action. That's what I was told, I haven't verified that. So they're going to change their procedure based on that. But now there's a clear commitment to Reg Guide 1.8 in their FSAR.

Let me back up to the other item before we change slides. The area of radiation monitoring, the channel operability test. The previous FSAR and the way Unit 1 was originally licensed, there was a commitment to do quarterly channel operability tests. That's to take each channel of the area radiation monitors, test the alarm capability, make sure they alarm at the appropriate point, make sure that they have full range of reading, et cetera. They had made a change, a 50.59 change from that commitment to a

periodic test per their procedures and that's what the original change to the FSAR stated. They went from a quarterly commitment to a periodic commitment. When I asked what "periodic" meant I got the 50.59 change package and some problems with the bases there. So the long and the short of the review is that the TVA has committed to quarterly changes or a frequency that's established by the performance of the same or similar monitors. So that it's a performance-based criteria now. The statistical acceptance criteria is that 95-95 acceptance. It's a 95 percent confidence that the individual monitor will pass the next test 95 percent of the time is what that means. And although I'm not an I&C guy I understand that's a standard I&C acceptance criteria for performance-based frequencies. Next slide.

In terms of the plant effluents, the liquid effluents there were a number of changes to the source term associated with the liquid effluents from the plant. Most of them had very minor changes to the overall dose. In fact, there were only very minor changes to the overall dose calculations. However, there was a significant change to the description of the source terms. TVA had changed the source term table that's there, Table 11.2-5 which gives the

normal operating source term which is actually the bottom slash there. I apologize for having these a little bit backwards. But the normal operating mode would be as was discussed earlier that the steam generator blowdown would be released from site unprocessed as long as it was below the trip setpoint on the monitor for the blowdown line, and that the condensate demineralizer, the effluent from the regeneration of the condensate demineralizer would also be released from the site unprocessed. If in fact there was operation with steam generator leakage in excess of that trip point the blowdown would be directed to the inlet of the condensate demineralizer and processed through the condensate demineralizer. Then there were two sets of source terms given in this change that would address either releasing the effluent from the condensate demineralizer regeneration directly to the environment without processing or to go ahead and process that effluent with the mobile demineralizer that's part of their normal rad waste processing.

The purpose of that Table 11.2-5 was to demonstrate that these modes of operation actually meet the 5 curie total release limit that's in RM 50-2 and those tables do in fact demonstrate that.

However, in response to a question that I had they also provided some tables that adjusted these total curies to an effluent concentration limit for those three modes of operation and compared them with the concentration limits in 10 CFR 20 Appendix B. The result of that analysis is that the -- for the normal operating mode they meet 10 CFR 20. For the operating mode in which they would process the blowdown through the condensate demineralizer and then process the condensate demineralizer through the mobile demineralizer that in fact meets Part 20 as well. However, without that additional processing with the mobile demineralizer it clearly does not meet Part 20.

So they will have to control how long -- now, the Part 20 concentration limits are annual average so it's the average concentration over the entire operating year. So obviously extended operation in that mode would not be acceptable. So they will have to administratively limit how long they can operate in that mode. And that would be covered by the technical specifications, the effluent technical specifications that'll be put into place in the offsite dose calculation manuals that are associated with that that control and limit the effluents. Although we haven't received the ODCM as

yet so we haven't reviewed that yet but that is going to be a part of it.

CHAIR RAY: When you talk about all these things is there, this is just a new review independent of Unit 1 the way it is today? Or do you link these things in some way saying this is different, this is the same, that sort of thing? I look at that, I listen to what you're saying, I can understand it but I'm just asking myself I wonder how they do it at Unit 1.

MR. PEDERSEN: The FSAR, Watts Bar was originally submitted as a two-unit site with a common FSAR. We reviewed that up to a certain point as a common two-unit site. We actually wrote a safety evaluation, Supplemental Safety Evaluation 16 that addressed both units operating. What I'm reviewing are the changes that have happened since then. The Unit 1 design basis when it was licensed per the Supplement 16, we only assumed that last bullet there. We didn't address extended operation with steam generator leakage. This was added to the Unit 1 FSAR and then the Unit 2 FSAR was changed to come into conformance with that. The actual dose calculations are based on that normal operating mode with minimal or steam generator leakage less than the trip

setpoint.

So the TVA recalculated the doses and we did an independent dose calculation as well which I'll get to. Other things that changed in that dose calculation were the population distribution around the site from the latest Census, I believe it was the 2000 Census, and then the annual land use survey that they do. They also incorporated the changes to that. And they were minimal changes. They calculated the dose, we calculated the dose. There were slight changes to the actual numerical values but the maximum individual, exposure to individual didn't change. The maximum exposed organ which is in the child did not change. And those doses will be presented in the table in a slide here that I have in a few minutes. Next slide.

The changes made to the FSAR didn't impact the liquid effluents very much but there was a significant impact to the gaseous effluents. In addition to some minor changes to the source term the dilution of the boron recycle system had a minimal impact. The change from 22 purges per year to a continuous filtered vent had more of an impact on the source term and we incorporated that into our re-analysis as well as TVA incorporated that in their

calculation as well.

The major changes though, however, were associated with the land use survey and the Census, the population distribution. Things have changed quite a bit around the plant since Unit 1 was licensed 15 years ago. In particular, the critical milk animal, the cow and dairy farm that was previously the limiting pathway no longer was in existence so that changed. There are still dairies around. I believe two out the -- three out of the previous five, six dairies are still in existence but. And then a garden, a local garden has actually been moved up closer to the site so it turns out that that local garden becomes more of a critical dose pathway than the iodine milk child pathway.

In addition to that the meteorology was changed as you heard earlier. TVA recalculated their dispersion and deposition factors. And of course since the location has changed the turbine correction factors that would be associated with that dose calculation changed since they're location-specific.

The last bullet there, I mentioned that we, the staff, did an independent assessment. Supplement 16 to the FSAR was our original independent assessment and our original safety conclusion was

documented in Supplement 16. We revised that, that initial staff independent assessment with our standard assumptions methods. We did use for the source term our own GALE code which is a slightly different code than what TVA used. We used, we calculated our own chi over Q's and D over Q's with a standard code called XOQ/DOQ which has been consistently used in licensing. And then we did our own dose calculations that are based on the GASPAR and LADTAP codes that have been around and been used in licensing since the '70s which are in fact different than the codes that Watts Bar used.

So this is the result. The first column there is the design objectives that are listed in 10 CFR -- excuse me, Appendix I. The second column are the TVA-calculated doses and the third column there is the NRC-calculated doses for those various criteria, liquids, total body, any organ, noble gasses and the airborne effluents, and then the last one is the radioiodine and particulate. There's a 15 millirem criteria for any organ, all pathways.

There's general agreement between the TVA and NRC assessments within about 10 percent of each other. Both of them indicate that they're well within the design criteria, their respective criteria. And

so there's not much of a problem there until you get to the last one. The 15 millirem for the airborne radionuclides and particulate, previously during the Unit 1 licensing was calculated out as 7.5 millirem per unit so there was a significant increase.

The significance is that TVA had committed to meeting RM 50-2. Go ahead and change the slide. RM 50-2 was actually the forerunner to 10 CFR 50 Appendix I. It has very similar design objectives as Appendix I with the notable exception that in some of those design objectives they were given, even though the numeric value was the same they were given on a per-site as opposed to a per-unit basis. And when that change was made and Appendix I was finalized the requirement for the licensee to do a cost/benefit analysis in addition to meeting the specific design criteria that are listed there, licensees are also required to do cost/benefit analysis to see that if modifications to the rad waste system could actually attain what's called a beneficial cost/benefit ratio at $1,000 per man-rem. However, there's an exception to that requirement that's built into Appendix I and that's for plants that received a construction permit between 1974 and '76 which TVA was. So Unit 1 was built to that exception.

They did not provide a cost/benefit analysis. They demonstrated that they met RM 50-2. That can no longer be concluded from the dose calculations, either the staff's or the licensee's dose calculations. A maximum organ dose of 9.15 implies a site dose of over 18 millirem which of course doesn't meet the 15 millirem requirement. So TVA was required to do the cost/benefit analysis.

We provide actually a very proceduralized analysis method in Regulatory Guide 1.110. It gives a list of what is considered technically feasible modifications, enhancements --

CHAIR RAY: 1975 dollars, are you kidding me?

MR. PEDERSEN: Yes. No, I'm not.

CHAIR RAY: Jiminy Christmas.

MEMBER STETKAR: When was Reg Guide 1.110 last updated?

MR. PEDERSEN: 1976.

CHAIR RAY: I don't know if anybody can calculate 30 years ago.

MR. PEDERSEN: Actually, the document itself gives a list of enhancements, technically feasible enhancements and gives the cost, the capital cost in 1975 dollars of what that would be. It goes

through an extensive procedure of taking the direct and indirect costs, adjusting them for capital --

CHAIR RAY: I know how to do it, I just -- it's --

MR. PEDERSEN: -- and adding the --

CHAIR RAY: You're getting almost a half a century of discounting here and that's a big number.

MR. PEDERSEN: Yes, but --

CHAIR RAY: The inflation of the '80s.

MR. PEDERSEN: That's actually addressed in the document. The rationale was if you're doing the cost/benefit ratio, if you assume that inflation adjustment would impact both the costs and the benefits the same it doesn't make any difference, they cancel each other out. That's the rationale built into the document. That's why $1,000 per man-rem hasn't been adjusted.

CHAIR RAY: All right, I see the point. Yes.

MEMBER RYAN: It makes it very hard to communicate what exactly it is you're doing, however.

MR. PEDERSEN: I agree, I agree.

MEMBER RYAN: I mean it's very arcane and I've got to tell you, I think about updating it.

MR. PEDERSEN: If it were me I would

probably recommend that as well.

CHAIR RAY: Yes, because the $1,000 would now be I don't know what but some big number.

MEMBER RYAN: A whole lot more.

MR. PEDERSEN: Well, NRR is actually in the process of trying to update that. The $1,000 per man-rem standard assumption that was built into a lot of our cost/benefit analysis not just for plant licensing, but for --

MEMBER RYAN: At some point it's simply a metric. It means nothing whatsoever to do with regular money. It's just some metric number that you're using to assess this versus that.

MR. PEDERSEN: That's true.

MEMBER RYAN: So yes, one approach would be to drop the dollars.

CHAIR RAY: That's right.

MEMBER RYAN: And just call it the metric, you know, the figure of merit calculation, whatever you want to call it. It does not represent real dollars and it's very hard to explain that to anybody that's not familiar with the history and use of it.

MR. PEDERSEN: Actually, the reg guide itself, you're right. It leads you into putting both the cost and the benefit in terms of dollars. The way

that TVA actually did the analysis and the way the analysis is being done these days in NRO I believe is consistent, in which instead of --

MEMBER RYAN: I challenge anybody to go try and teach a class of young engineers what it all means. You'd get done with it in a day.

MR. PEDERSEN: It took me more than a day to try to figure it out. I've never, I've licensed, I've done reviews in the past when we were doing quite a bit of reviews, in fact, I did the Chapter 12 review for Unit 1 15 years ago and this is the first time I've ever had to go through this, the cost/benefit. I understand NRO with the new reactors have in fact done a number of these assessments.

The way TVA did this assessment, instead of putting things in terms of dollars they put things in terms of person-rem, in terms of the collective dose. The calculating out a cost for an enhancement, if you've got $20,000 that would imply that you'd have to have at least a 20 person-rem savings to come up with that beneficial cost/benefit ratio and so it was done in terms of dose saved and how much dose would have to be saved to benefit that. So that's how they did their analyses.

And they went through, it's $1,000 per

person-rem, that's both total body and person thyroid rem. So it's collective thyroid rem as well. The person-rem was fairly easy to demonstrate that the lease expensive modification listed in the guidance document would require more dose savings, total body dose savings than the operation of the unit actually results in.

MEMBER RYAN: So that raises another issue that having a separate individual organ dose when we have effective committed dose is another longstanding rule.

MR. PEDERSEN: Yes, you're right. We did not do this review in terms of effective committed dose. It's to demonstrate compliance with Appendix I which is based on ICRP 2. We did not make a conforming change.

MEMBER RYAN: For those that don't know ICRP 2 was written in 1959.

MR. PEDERSEN: Yes, yes. And it's one of the issues that we have right now that we have an ongoing process of trying to adopt the latest ICRP recommendations and making conforming changes, particularly to Appendix I is one of the main bullet items on the list.

So, as I said, TVA provided that

assessment. I've reviewed it. My review is documented in Supplement 25 there. The staff did an independent assessment. We, as I said we had our own chi over Q's, our own offsite dose calculations based on our own set of standard assumptions. Our doses were slightly higher than TVA's in most cases and our, the costs were slightly lower and that's because within the document that capital recovery cost, there's a range of factors that are given in the guidance. TVA used a factor that's in the middle of the range. I used the low end of the range to minimize what the cost would be. And even by minimizing the cost and having slightly higher doses I did not come to a beneficial cost/benefit ratio. So I, you know, verified TVA's conclusion that no enhancements to the rad waste systems would be warranted.

MEMBER ABDEL-KHALIK: Doesn't this approach sort of constrain licensees and prevents them from taking advantage of advances in technology?

MR. PEDERSEN: I don't see the point -- no, I don't see how it could constrain them.

MEMBER ABDEL-KHALIK: I mean, you know, if you can't do the cost translation correctly, if you're using obsolete numbers and something comes up that it

an advance in technology, if you can't do the cost/benefit on apples to apples comparison you're sort of not allowing them to make that comparison.

MR. PEDERSEN: The licensees are free to add, to go way beyond what we require. It actually constrains the staff as to what we can.

CHAIR RAY: I think the way to think about it is it would be interesting to know what the heck is $1,000 in 1975 dollars today. What is it?

MR. PEDERSEN: There was extensive bases for coming up with that at the time.

MEMBER RYAN: But it's out of date dramatically.

MR. PEDERSEN: I agree.

MEMBER RYAN: I mean, the dosimetry is 60 years out of date and the financial basis is 40 years out of date.

CHAIR RAY: When you escalate the dollars from '75 to today using whatever the, there are different inflation factors you could pick, but when you do that what number do you come up with?

MR. PEDERSEN: As I said, NRR is going through that process right now. They haven't come up with a number. They are in the process of updating that $1,000 per man-rem. Not for Appendix I because

this guidance requires this process but the staff itself through the backfit rule if we have to backfit a licensee or backfit a requirement on a licensee or do rulemaking we have to do a cost/benefit analysis to justify that backfit.

CHAIR RAY: So one would think that you would know what the number is.

MR. PEDERSEN: So that updated value will be applied to our own analysis.

CHAIR RAY: I mean somebody here you would think would know what $1,000 in '75 dollars is today. You guys know.

MR. BRYAN: This is Bob Bryan. TVA has as part of their design process a cost/benefit for looking at ALARA changes and we use $25,000.

CHAIR RAY: Twenty-five? Okay. Well, that's a number that I wouldn't quibble with. It's just, you know, hard to -- if as Mike was saying, if you're talking to members of the public $1,000 just doesn't make any sense, but $25,000 which is the real number I presume that one gets when you escalate 1975 dollars to --

MEMBER SIEBER: That's pushing it.

MR. PEDERSEN: There's a range of values that are used.

MEMBER SIEBER: It's a factor of 10 maybe, but not 25.

MEMBER RYAN: It clearly costs a whole lot more to save a person-rem than $1,000. Whether it's 25 or 50 or some number in that range for various kinds of 1 rem savings I'm sure there's a range of numbers. It's not one number.

CHAIR RAY: Well, $1,000 will translate into one single number depending on what escalation factors you want to use.

MEMBER RYAN: I understand that.

CHAIR RAY: I'm just asking the question what is the number.

MEMBER ABDEL-KHALIK: A lot less than $25,000.

CHAIR RAY: Okay.

MEMBER SIEBER: Maybe 10.

CHAIR RAY: I'm not sure. That's a long time and if you compound the --

MEMBER ABDEL-KHALIK: Still a lot less than $25,000.

CHAIR RAY: All right.

MEMBER STETKAR: The last 20 years inflation hasn't been --

CHAIR RAY: I just remember when it was

running 18-19 percent. Anyway, but that was construction.

MEMBER ABDEL-KHALIK: So would you still use that $25,000 per man-rem for things like evaluating zinc addition?

MR. BRYAN: If we follow our procedure yes, we would.

CHAIR RAY: Okay. I'm sorry to divert things.

MR. PEDERSEN: That's my last slide.

CHAIR RAY: All right. Now, you've got two colleagues here but it's now 2:30 and I assume you each have your presentations to make, John first and then Leta.

MR. POOLE: Well, actually John has his presentation on the accident dose.

CHAIR RAY: Right.

MR. POOLE: Leta is actually here just to support his review, so.

CHAIR RAY: All right. Well, I thought I saw her name here listed on the meteorology.

MR. POOLE: Correct, but in preparing the slides we just kind of lumped them all to one.

CHAIR RAY: All right, that's fine. Well, I hate to ask you to do this but if we go through your

presentation we'll wind up running I'm afraid later than we should to take a break so I need to give people a break here and we'll do that for -- until 20 minutes to the hour, and then we'll resume. For the balance of the day.

(Whereupon, the above-entitled matter went off the record at 2:27 p.m. and resumed at 2:41 p.m.)

CHAIR RAY: So let's do that and we have one more two-part presentation I guess from the staff. So let's proceed with that, Justin.

MR. POOLE: Okay. Yes, the next part of the presentation is to go over the status of the design basis accident dose consequence evaluations. With me I have John Parillo and Leta Brown who are both from the Accident Dose Branch. John?

MR. PARILLO: Okay. My review focused on identifying the difference between Watts Bar Unit 1 and any changes that were made for Watts Bar 2. So basically I asked the applicant to identify for each accident all the major inputs and show, you know, in table form what that value is for Unit 1 and what it is for the Unit 2 and explain any differences. So that, they did that and kind of condensed the major differences on this slide. We've already talked about the updated atmospheric dispersion coefficients, chi

over Q's, and of course the differences in the steam generators which affect mainly the releases from the secondary side. And of course this Unit 2 at least right now is not intended to be licensed for tritium production so that affects source term for the accidents. And the updated dose conversion factors which resulted in a lower dose equivalent iodine, that should say tech spec limitations on the primary coolant. And the other difference was that for Watts Bar Unit 2 they added some release scenarios, additional release scenarios for the fuel handling accident, and in those additional release scenarios they incorporated the insights from the alternative source term using Reg Guide 1.183.

MEMBER RYAN: John, can we just clarify the iodine point you made? The lower dose equivalent iodine coolant values means the concentration allowed in coolant is low.

MR. PARILLO: Is low.

MEMBER RYAN: Because the dose conversion factor went up.

MR. PARILLO: Because, yes, when -- if you have a given mixture -- and for dose equivalent iodine they restrict it to iodine-131 through -135, so you look at those five isotopes. And for a given mixture

if you use the DCFs from ICRP 2 which is also what's in the old Technical Information Document 1844 you will come out with a higher dose equivalent iodine-131.

MEMBER RYAN: Per unit activity.

MR. PARILLO: Yes, for that same, and if you look at that same concentration and you use updated dose conversion factors you'll come up with an actually fairly significantly lower --

MEMBER RYAN: Lower dose.

MR. PARILLO: So when that translates you end up with a more restrictive tech spec. And they have actually which I was going to get to a little later is they have very restrictive coolant activity tech spec limits, both for the long-term operation and for the iodine spike, the short-term relative to many other plants.

MEMBER RYAN: Thanks for clarifying. I think it's very important for folks to get right what's getting bigger and what's getting smaller and all of that.

MR. PARILLO: Right. And of course that has -- as a reviewer to me I thought it was worthy to mention that the offsite dose, and this slide says just offsite but it's actually true for control room

as well, that all of the dose consequences for Watts Bar 2 are low relative to the acceptance criteria. And there's a couple of reasons that I listed here in my notes for that. One of them is that they have a very effective dual containment design so that all of the containment leakage is captured and processed prior to release. And also the ice condenser system does have beyond the pressure-reducing characteristics there is also an iodine absorption that's used and some credit is taken for that as well.

CHAIR RAY: John, let me interrupt you a second. Let me ask the applicant, you still refer to this as the shield building though, rather than a secondary containment, don't you?

MR. BRYAN: Yes. This is Bob Bryan. We have a shield building that's the typical annulus secondary containment that is typical of many plants, but when you get out to the auxiliary building there's a large portion of the auxiliary building that is also maintained as a part of the secondary containment boundary. It's kept at a negative pressure relative to the outside and it has HEPA and charcoal filters on it. And so the leakage from the containment is apportioned 75 percent to the annulus and its filtration system, and the other 25 percent is treated

by the auxiliary building gas treatment systems, and that's --

CHAIR RAY: Do you refer to that as the secondary containment?

MR. BRYAN: The whole thing we call the secondary containment boundary.

CHAIR RAY: You do? Both the shield building and the portion of the auxiliary building?

MR. BRYAN: Yes. And the design was set up so that we had no, at the time no unfiltered out-leakage from the plant.

CHAIR RAY: All right, thanks.

MR. PARILLO: Thank you, Bob, you just covered my next point which I was going to mention that not only is all of the things that Bob mentioned, but those filtration units are also very robust. They have two carbon beds in a series and per our regulatory guides are allowed to assume 99 percent removal. It's probably higher than that but we cap it at 99 percent. So, not only is all of the leakage processed but it's processed very effectively. And there's probably other reasons but those are the main reasons that I focused on.

So that, in this particular slide we're talking about a loss of coolant accident and the doses

being well within 10 CFR 100.11. Now, when you use the term "well within" in the design basis accident dose nomenclature that actually is a defined number. It refers to less than 25 percent and that's usually applied to, or not usually, it is applied in a regulatory sense to, for instance, the fuel handling accident and also the rod ejection accident and that. So the key here is that for the LOCA that in some cases was -- used to be referred to as the maximum hypothetical accident. That's the accident that actually we're talking about in the regulation where the numbers are delineated, you know, a substantial core damage accident. So in the case of Watts Bar 2 their maximum hypothetical accident, their LOCA analysis for dose consequences, their doses are actually less than 25 percent of the 10 CFR Part 100 values. That becomes important for the next bullet down.

Incidentally then, getting back to their very restrictive coolant, tech spec coolant values helps them in terms of the main steam line break and the steam generator tube rupture. Their doses there are well below the applicable regulatory requirements. So, and that's directly related to the restrictive tech specs that they have on the coolant.

Now, in terms of this next bullet on the rod ejection accident the applicant's statement was that the rod ejection accident was bounded by the LOCA. And of course in terms of the source term release that's an obvious, you know, obvious statement that you're going to have a much more, you know, energetic release in a LOCA. But the complication becomes in terms of in regulatory space, at least in the regulatory guide space is that the accepted criteria for the accident is different. For the LOCA we accept the full 100 value, but for the rod ejection accident we say it has to be well within. So that's why the first bullet is important, that the LOCA for Watts Bar 2 actually has doses that are well within. So if you go through the logic then their conclusion that the rod ejection accident would be bounded by the LOCA then makes sense both from the release of fission products and also the, you know, how that affects where you are in relation to the regulatory limit for the accident. So I hope I didn't confuse anybody on that.

CHAIR RAY: No.

MR. PARILLO: Okay. And the other difference had to do with the way Watts Bar 2 has looked at the fuel handling accident. And I was a

little sloppy when I made this slide, so. The first bullet should read, the first scenario, release scenario should read, "The containment closed to the auxiliary building with credit for the reactor building purge ventilation system filtration" which is another filter system. They use very conservative, took credit but not much credit for that system because of concerns with humidity. So that, but that was using, when I say traditional assumptions I mean non-alternative source term assumptions and used the whole body and thyroid dose criteria. So that was the first release scenario and that was pretty much more akin to what's in the licensing basis for Watts Bar Unit 1.

Then the next two were additional scenarios that they evaluated. And for release in the spent fuel pool in the auxiliary building with no credit for filtration using the alternative source term assumptions and with the dose acceptance expressed in terms of total effective dose equivalent instead of the whole body and thyroid. And the third release, again this was -- should read "The containment open to the auxiliary building with no credit for filtration." And that was also done using the alternative source term and of course the TEDE

acceptance criteria. And all of these scenarios meet, again, this is -- for fuel handling accidents we also use this well within, so less than 25 percent of the 10 CFR 100.11 limits. And so that's, you can go to the next. So the conclusion is that design basis accidents predict doses within applicable regulatory acceptance criteria and that we didn't have any open items for this portion.

CHAIR RAY: All right. Any questions? Okay. Was there anything more to be said on the meteorology?

MS. BROWN: No.

CHAIR RAY: Okay.

(Laughter)

MS. BROWN: There were no questions as far as I understand it.

MR. PARILLO: She already asked him all the questions.

CHAIR RAY: Okay.

MR. PARILLO: Thank you.

CHAIR RAY: Thank you. Justin, do you have anything more before we turn to open items?

MR. POOLE: Not really. Take one minute here. Just the summary of what we have remaining, and we've kind of already gone over this for the most

part. The staff review is nearing completion. Some of the future milestones are listed here on this slide, doing the SER and issuance of a license. I'm sorry, issuance of the final environmental supplement for the license. Completing our ACRS review. Going through ASLB and then some regional items regarding operational rate assessment and the certification of as-built.

For the next meeting, as we said before we have the next subcommittee meeting scheduled for April of 2012. The main focus will be fire protection and closure of open items. So I think at this time is probably a good spot that we.

CHAIR RAY: Yes, I want to review the open items and if there are any public comments open the phone line, and with that we'll probably be done. So if I could ask members to, and anybody else turn to HH in the SSER 25 appendix where the open items are listed. As Justin explained earlier the confirmatory items reflect staff agreement where some action is still required to be taken and the vast majority of items open simply to ensure that it is in fact done as agreed upon. So it's not my intention to focus on the confirmatory items but if anybody has anything they want to comment on about a confirmatory item please

speak up. But all I want to do is go over the other open items and see in a little more pedantic way if there's anything here that needs to be on the agenda for the next and potentially final, but that'll have to be seen, subcommittee meeting.

So the first one I see that's not a confirmatory item is listed here, is 12 on page 2, and refers to an audit to verify implementation of some requirements. Thirteen, IST program before OL issuance. Normally we would not review that. Sixteen has to do with the environmental qualification and again presumably we are not concerned with any review there. Seventeen, similarly. Twenty-three is a confirmatory item. Twenty-five has to do with insurance, not a matter of concern to us. Twenty-six has to do with an accident in one unit, concurrent shutdown of the second unit without offsite power. Unit 2 pre-op testing will validate diesel response sequencing loads on Unit 2 emergency diesel generators and the staff will evaluate the status of this issue. Again, it appears the requirements are clear enough and this is really in the form of test performance.

Thirty has to do with degraded voltage relay setpoint dropout settings and the confirmation the tech specs are properly derived from those. Not

something we would review I don't believe. Thirty-two, emergency diesel generator voltage and speed range and so on having to do with tech spec surveillance requirements. Nothing there I don't think. Next one is confirmatory item then there's 35, information concerning feedwater purity requirements. I don't have any interest in seeing that come here unless somebody else does. Then we've got a series of confirmatory items till you get over to 47 which is a, let's see. It's a water-sealed valve leakage test results and a discrepancy that existed needs to be resolved there. That doesn't appear to require ACRS further review.

Confirmatory items till you get to 59. ESF system materials with containment sprays and core cooling in the event of a LOCA is incomplete pending resolution of GSI-191 which raises a question I've been intending to find a place to ask and that is to direct to Justin. What's the outlook on 191 as far as Watts Bar 2? Why all this concern? Is it treated like an operating plant from the standpoint of 191?

MR. MILANO: Yes.

CHAIR RAY: Yes, Pat.

MR. MILANO: Yes, we are doing the review of GSI-191. Actually, the staff has already drafted

a relatively complete safety evaluation for GSI-191. However, there is one outstanding issue as it relates to all the plants and that's the treatment of in-vessel effects. And that's what's been holding us up from issuing a safety evaluation to resolve that. What we, we have been in dialogue with TVA and we've been, not to say that this is going to be the staff approach but one of the things we're thinking about is as you've heard in the past TVA did a lot with the Unit 2 containment to remove all the fibrous material and basically we consider it to be a zero fiber plant. So the --

CHAIR RAY: Call it a low-fiber plant.

MR. MILANO: A low-fiber plant. And so one of the things that we have been conversing with TVA on is for them to come in with some type, barring the staff's ability to generically resolve the in-vessel effects issue and the methodology that TVA would come in and make an argument, you know, with regard to the minimal fiber and the fact that what its impact is on, you know, in-vessel effects. And that it's, that we could make some type of reasonable assurance decision in advance of, you know, of a more generic review of it. And that's one of the things we're thinking about doing but I can't say at this

time for sure.

CHAIR RAY: All right. Let's identify 61 as one that we'd like a status on at the next subcommittee meeting.

MR. SHUKLA: But I would note that Unit 2 is different than Unit 1.

CHAIR RAY: Of course. Am I confusing them somehow?

MR. SHUKLA: No.

MR. POOLE: Just to clarify, you're actually talking about number 59.

MR. MILANO: Fifty-nine.

CHAIR RAY: Oh, was I? Okay. I've got my finger on the wrong thing here. I'm sorry. I was going to ask Said about 61, that's why.

MEMBER ABDEL-KHALIK: Well, we have a very large margin as far as the peak clad temperature for a large-break LOCA but I think it would still be interesting to find out what the result of that discrepancy will be.

CHAIR RAY: All right, so you'd like to treat it similar to 59 --

MEMBER ABDEL-KHALIK: Correct.

CHAIR RAY: -- which I meant to refer to. All right. Okay, that confirmatory item still 65.

MEMBER BROWN: Sixty-three, even though it's a confirmatory item, it's -- I don't know how to differentiate between that and 93. They are both addressing the same issue so they kind of go hand in hand.

CHAIR RAY: Okay. Would you like discussion of that?

MEMBER BROWN: Well, yes.

CHAIR RAY: For a status?

MEMBER BROWN: Yes, it's hand in hand with 93. I think if you do one you've got the other one.

CHAIR RAY: All right.

MEMBER BROWN: If I understand 93 correctly. I don't know that 93 is, that's an NRR resolve. This one is a region. They're both -- 93 is also Region II. Yes, they ought to be lumped together.

CHAIR RAY: Okay. Now do you want to say anything more about what your interest is so that we get the right information?

MEMBER BROWN: Am I supposed to remember what I said earlier?

CHAIR RAY: Only if you want to.

MEMBER STETKAR: The answer is no, you don't want to say anything more.

MEMBER BROWN: The answer is whatever I said in the transcript is what I'd like to hear about. I thought I was fairly complete.

CHAIR RAY: All right.

MEMBER BROWN: Some of that involves staff, I mean Region II and some of it involves staff.

CHAIR RAY: Enough.

MEMBER BROWN: Yes, enough.

CHAIR RAY: All right, 65 is the next item. I'm not sure what the heck it's about.

MEMBER BROWN: I was going to ask. I don't know what WCAP-13869 is, so.

MR. POOLE: All it was was there was a difference between -- I don't recall what the WCAP is either.

MEMBER BROWN: It's a check --

MR. POOLE: It's an I&C. Right. But there was just a difference between, and the Unit 1 was using one revision and Unit 2 was using another.

CHAIR RAY: All right.

MR. POOLE: Staff has actually -- already has one closed for 36.

MR. SHUKLA: Gentlemen, I think Mr. Brown was interested in number 64 also.

MEMBER BROWN: That's a -- no. I looked

at that. That's a test item. Somebody should read the results and they'll know whether it's okay or not. We don't need to see that.

CHAIR RAY: All right, thank you. Okay, moving on. Seventy --

MEMBER STETKAR: Sixty-seven, but that's kind of similar. That's the whole probable maximum flood thing. I mean this is, once you figure out what it is.

CHAIR RAY: I saw that and --

MEMBER STETKAR: That's -- I mean, I can go measure heights.

CHAIR RAY: I would think so, yes.

MEMBER STETKAR: I would think so.

CHAIR RAY: All right. Seventy, that doesn't appear to be anything requiring ACRS attention or review. Seventy-one I thought was kind of interesting but I don't want to ask for review here. Seventy-seven --

MEMBER BROWN: What's HRCAR? HRCAR monitors. Are those atmospheric? Are they radiation monitors?

MR. MILANO: High-radiation containment atmospheric monitors.

MEMBER BROWN: Okay.

MEMBER SIEBER: High-radiation containment area monitors.

MEMBER BROWN: All right.

CHAIR RAY: Okay. Pass on that?

MEMBER BROWN: Yes, I'll pass on that.

CHAIR RAY: Seventy-nine.

MEMBER BROWN: Unless Mike wants me to do something.

MEMBER RYAN: They're okay, Charlie.

MEMBER BROWN: You happy?

MEMBER RYAN: I'm happy.

MEMBER BROWN: Thank you.

CHAIR RAY: Okay, 79 deals with the same monitors. Any different comment there? I take it not.

MEMBER BROWN: No.

CHAIR RAY: And then there's a how do we meet this reg guide in number 80. Pass on that. Eighty-one, compliance with EPRI document here for staff review again wouldn't normally come to us I don't believe. Moving down to 91. This is one that's a little more interesting and do you want to say something, John, about it?

MEMBER STETKAR: No, I don't because I don't remember what it's all about.

CHAIR RAY: All right. Let's add it to the list.

MEMBER STETKAR: We probably should hear about it.

CHAIR RAY: Yes. So 91 is something we want to hear about. Ninety-three we've covered, thank you. Ninety-four, you're satisfied with that?

MEMBER BROWN: Yes. These are roughly, we're going to go through the IEEE standards and confirm that they meet the specific requirements of the IEEE spec.

CHAIR RAY: Same on 98 and 101?

MEMBER BROWN: Because 93, 94, 95.

CHAIR RAY: There isn't any 95.

MEMBER BROWN: I'm sorry, 98, 101, 105, 108. I went through these, I didn't see any reason to --

CHAIR RAY: Okay.

MEMBER BROWN: -- to pull harder on those.

MEMBER RYAN: That includes 110 and 111 too.

MEMBER BROWN: Including 110 and 111.

CHAIR RAY: Yes, all right. Then we have confirmatory items down to 118. I don't know, it's -- Said, do you have any interest in that? I'm not sure

what the heck.

MR. MILANO: That's the wind size fixed in core probes.

CHAIR RAY: Yes. Would be operable following failure of SPMD. Care about that? All right. One twenty, John?

MEMBER STETKAR: No.

CHAIR RAY: All right. One twenty-one, no. One twenty-three, no. One twenty-five, no. EQ testing, yes. One twenty-six? Yes, that's right. It just didn't say -- it says environmental qualifications.

MEMBER STETKAR: They decided to spell it out.

CHAIR RAY: All right. One twenty-seven.

MEMBER STETKAR: No.

CHAIR RAY: Okay. One twenty-nine?

MEMBER BROWN: That's for minimally insulated cable on 127, right? Is that right? Is that what you're talking about, MI cable?

MR. MILANO: Yes.

MEMBER BROWN: Okay.

CHAIR RAY: One twenty-nine seems pretty far down in the weeds. One thirty-one. While I'm trying to ponder that one do you have some thought

about it, 131?

MEMBER STETKAR: No, that's just making sure that --

CHAIR RAY: Yes. Got the right numbers.

MEMBER STETKAR: They've got the right numbers in the EOPs to take action.

CHAIR RAY: One thirty-two.

MEMBER STETKAR: Yes.

CHAIR RAY: Okay, add that to the list.

MEMBER STETKAR: That's the boron dilution, basically timing analysis.

CHAIR RAY: Okay, 132 is on. One thirty-three?

MEMBER STETKAR: I'd say 133 and 134 together. They're part of the flood stuff.

CHAIR RAY: Yes, and again, there's both an interest in -- we've got the right action being taken but more profoundly why are we doing it the way we're doing it. And I think, I mean I could provide an answer but because we're putting in the Unit 2 OL stuff that the basis of which isn't there, it's elsewhere, we want to understand clearly are we doing the right thing here in adopting this time sequenced license condition that says at certain points in the future we're going to provide, basically change the

licensing basis over time. And I think I understand all that I need to on that, I just want to make sure that I understand what the staff's thinking about it is, and for sure we're going to want to recognize this in the letter that we write and I want to get it right. Okay.

MEMBER ABDEL-KHALIK: Mr. Chairman, there is something I'm interested in. I don't know if you've had the opportunity to review it in the past since I haven't been attending these subcommittee meetings and that pertains to the turbine-driven aux feedwater pump room heat-up during station blackout.

CHAIR RAY: Certainly not. And the reason I said it the way I did was you said during station blackout. And you were thinking about the station blackout that is the existing licensing basis?

MEMBER ABDEL-KHALIK: Correct, correct.

CHAIR RAY: Okay.

MEMBER ABDEL-KHALIK: We just want to see whether that is actually limiting as far as station blackout coding time.

CHAIR RAY: So it's the heat up of the --

MEMBER ABDEL-KHALIK: Turbine-driven aux feedwater pump room.

CHAIR RAY: Interesting, okay. So make a

note of that, Girija. All right, I think the last one here is 134 or did we cover that as part of the -- we did. Okay. So that's all the non-CI items in the --

MR. SHUKLA: Can I just go over quickly on the exact numbers?

CHAIR RAY: No.

(Laughter)

CHAIR RAY: Use the transcript. I'm not going to go through it again. I mean, you know, we do it once. I'm not going to do it again. So with that I think we're to the point where we'll ask whether staff or applicant have anything more, and we'll ask for any public comments before I quit. You guys have anything else?

MR. POOLE: We have nothing else.

CHAIR RAY: Applicant?

MR. KOONTZ: Mr. Chairman, this is Frank Koontz again. We do have one open question and that was the main steam line break pressure inside containment and it's 9.29 psig.

MEMBER ABDEL-KHALIK: Thank you.

CHAIR RAY: Okay. Girija, can we get the telephone line open in case there's somebody that's been sitting there wanting to speak to us. It's open, is it? Is there anyone on the phone line who would

wish to make a comment to us?

MR. SHUKLA: There is only one staff person was online and he's not needed anymore.

CHAIR RAY: Okay. But you never know.

MR. SHUKLA: Yes.

CHAIR RAY: Somebody may call in. All right, and there's no one here in the audience who's asked for an opportunity to speak to the subcommittee? Okay, with that then let's go around the table here and see if we've captured everything that everybody wants to talk about and we'll adjourn. Charlie?

MEMBER BROWN: No.

CHAIR RAY: Mike?

MEMBER RYAN: Nothing further, Mr. Chairman.

CHAIR RAY: Okay. John?

MEMBER STETKAR: Nothing.

CHAIR RAY: Said?

MEMBER ABDEL-KHALIK: Nothing.

CHAIR RAY: Dick? Jack?

MEMBER SIEBER: Nothing to add.

CHAIR RAY: All right. I have nothing to add. With that we will adjourn.

(Whereupon, the above-entitled matter went off the record at 3:15 p.m.)

TENNESSEE VALLEY AUTHORITY
WATTS BAR NUCLEAR PLANT UNIT 2

WBN Unit 2 ACRS Presentation

December 15, 2011

Agenda

- Watts Bar Status Update - Dave Stinson
- Meteorology and Radiation Protection - Robert Bryan
- Radiological Consequences of Accidents (Chapter 15.4) – Robert Bryan
- Transient Analysis (FSAR Chapter 15) – Frank Koontz
- Questions

Watts Bar Unit 2 Status

WBN2 Completion Status

- Project Status Update
  - Safety
  - Quality
  - Safety Conscious Work Environment
- Organizational Structure / Alignment
- Appendix HH Status

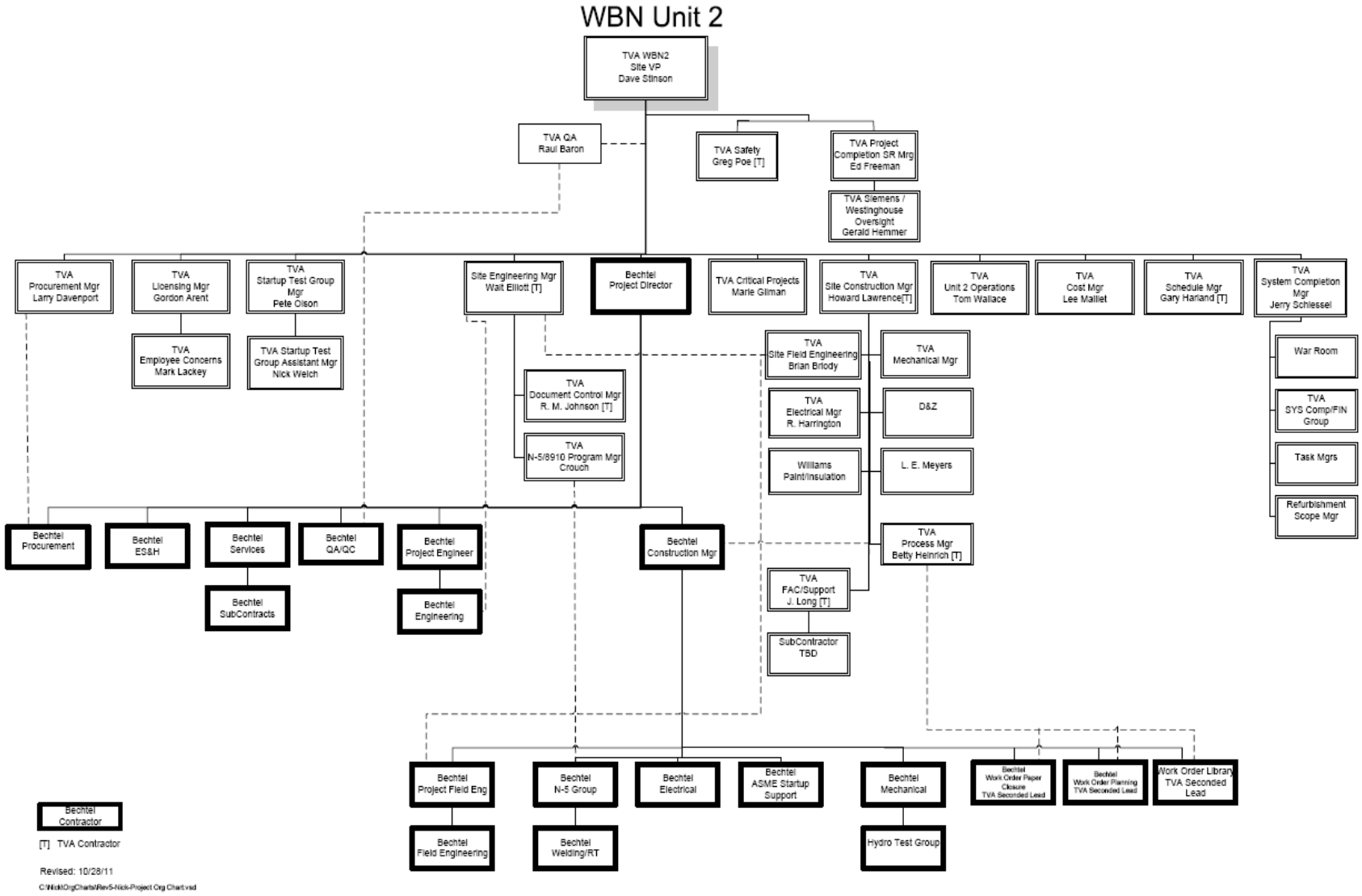
SAFETY – Highlights

- Highlights
  - Over thirteen million safe work hours since the last lost time accident (3/10/2010)
  - Fiscal Year 2011
    - Worked 7,409,301 hours with a total of eighteen recordable injuries (0.49 injury rate)
    - Over 28,426 Supervisor's Safety Observation performed
    - The craft turned in 1,718 intervention cards

Organizational Structure / Alignment

- The Bechtel and Williams Services contract facilitated a change to a new organization structure.
- Organization revised to reflect TVA's leadership role with responsibility for
  - Assigning work priority
  - Day-to-day direction
  - Schedule performance
- Key vacancies have been identified.
- Several highly experienced people recruited and on board
- Plan for remaining key vacancies has been developed and is in work in conjunction with Human Resources
- Next steps include Bellefonte Nuclear site transition plan

Organizational Structure / Alignment



QUALITY

- The Bechtel Quality Assurance Program and Manual remain in place for construction completion
- Program includes all quality control inspections, quality assurance audits and surveillances
- Inspection results are monitored by activity and craft for recognition of trends and required corrective actions
- Document review results are monitored and fed back to originating organization
- Line organizations develop corrective actions for recognized trends and common issues
- TVA Quality Assurance manager provides oversight for the program

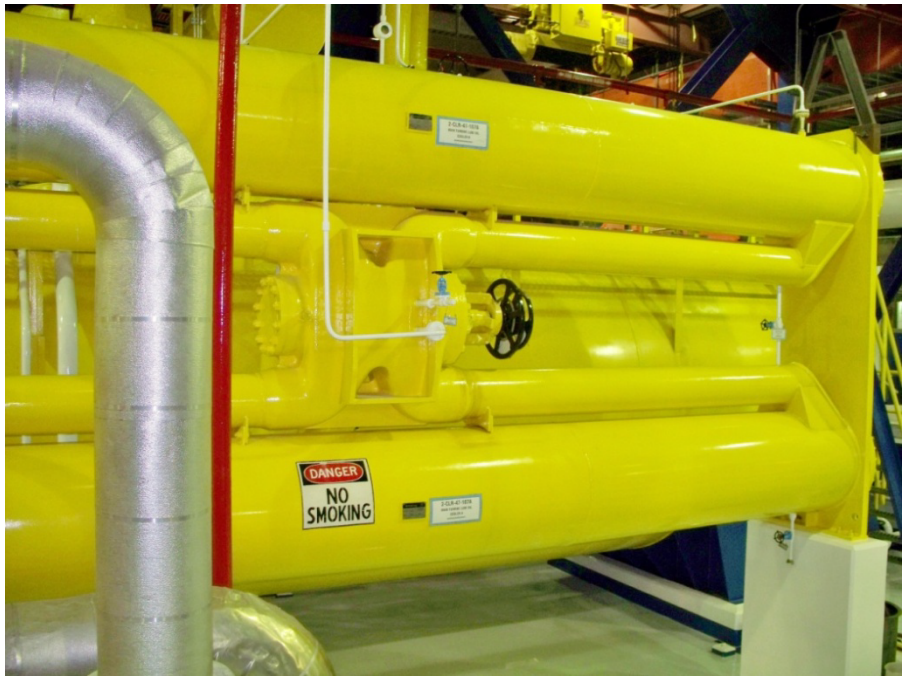
SAFETY CONSCIOUS WORK ENVIRONMENT (SCWE)

- Maintain improvements in the overall work environment
  - Communication - *from management to all employees*
  - Allowing time to listen - *keeping the door, and the ears, open*
  - Casual monitoring of the environment by Employee Concerns Program (ECP) - *monitoring by walking around and engaging people*
  - High visibility of ECP - *be seen in the plant and in meetings to develop familiarity that leads to trust*
- Ensure the SCWE message is rolled into the daily business focus with the same importance and acceptance as safety and quality – *weekly SCWE focus message for the project*
- Timely resolution of issues brought to the ECP

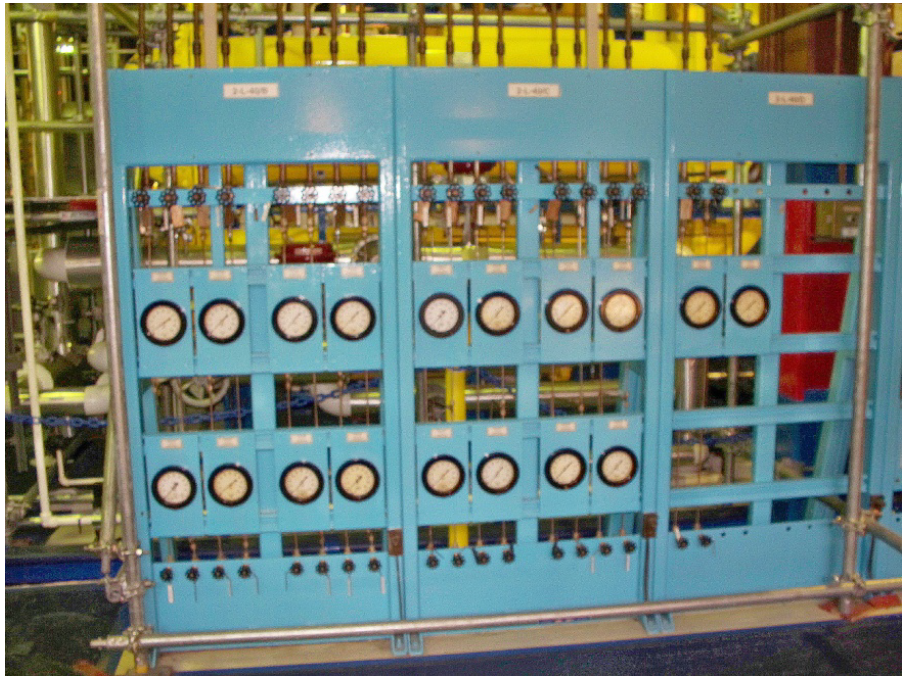
SAFETY CONSCIOUS WORK ENVIRONMENT (SCWE)

- Highlights
  - Improved Allegation Performance 2011 over 2010
    - Calendar Year 2010 – twenty-six onsite
    - Calendar Year 2011 – four onsite, as of 9/30/11
      - January – one
      - February – one
      - August – one
      - September – one

TURBINE BUILDING PHOTOS



TURBINE BUILDING PHOTOS



TURBINE BUILDING PHOTOS

TURBINE BUILDING PHOTOS

STARTUP & TESTING - Goals

- Developed a comprehensive testing program to demonstrate plant and system performance meet design requirements. The program ensures:
  - Regulatory requirements are met
  - Final Safety Analysis Report (FSAR) Chapter 14 requirements are met
  - Individual components are tested in accordance with industry standards and show readiness for pre-operational testing
  - Thorough demonstration of systems' performance against design requirements
  - Test conduct does not impact the operation of U1

STARTUP & TESTING - Overview

- Component level testing (circuit checks, valve strokes, motor runs, calibration)
  - Current count is 8316, currently 23% complete
  - Challenged by unit interface program restoration and support systems (control air)
- System flushing
- Preoperational test and Acceptance test performance
  - PTI governed by RG 1.68 and FSAR
  - 43 of 119 procedures approved, two test procedure performances completed
  - Overall procedure generation is 71% complete (20 in Joint Test Group (JTG) review cycle)
- All testing/flushing performed by Startup under New Generation Development and Construction (NGDC)
- Thirty-eight of eighty-six systems turned over to startup
- Four system turnovers completed to Nuclear Power Group, two more scheduled by end of year

START-UP & TESTING - Current Status

- Current Status
  - Refueling Water Storage Tank (RWST) and Primary Water Storage tank filled to pump suctions
  - Condensate and feed water in service via condensate hotwell pump, booster pump runs in progress
  - Condenser circulating water in service
  - Raw cooling water in service
  - Generator and Main Turbine oil systems placed in service weekly for turning gear operation
  - Annunciator and computer systems in service
  - Solid state protection / Eagle racks and Foxboro I/A ready for calibrations
  - Main feed water pump (MFWP) oil systems filled to support feedwater flushing
  - Control air flushing in progress and being placed in service to loads

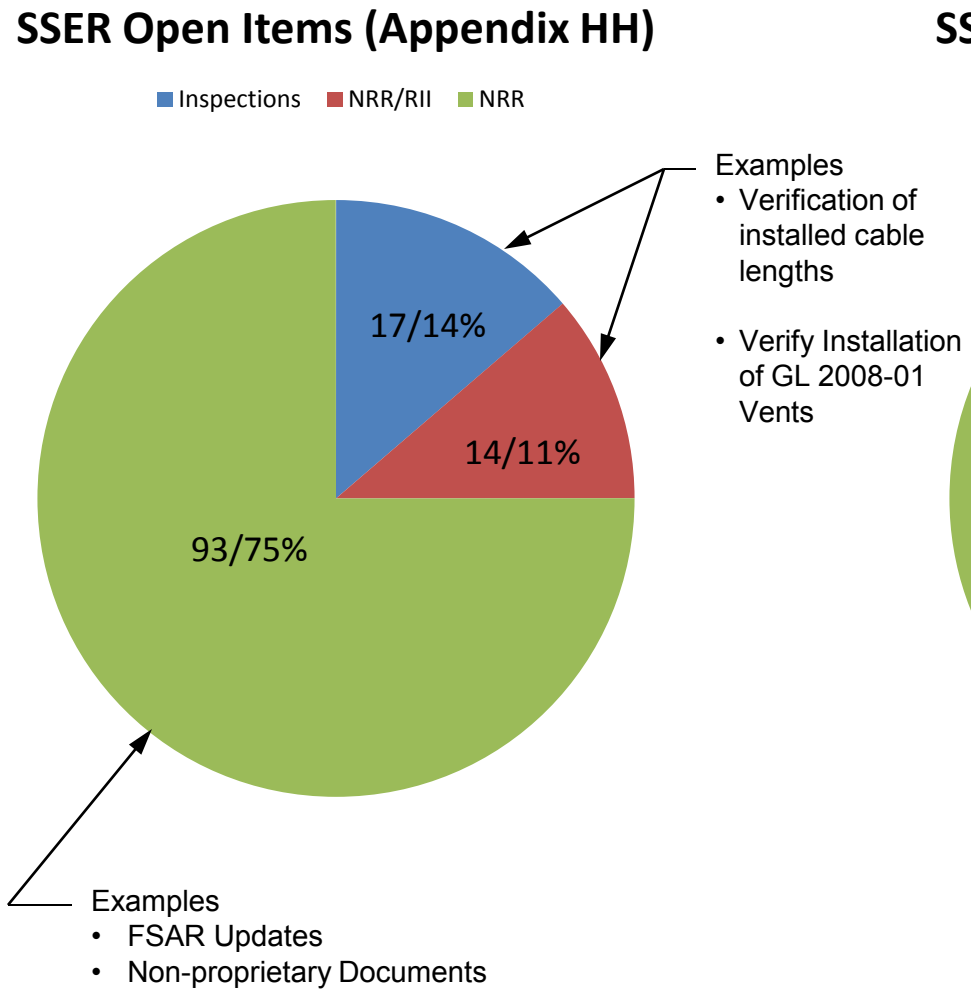
Transition to Operations

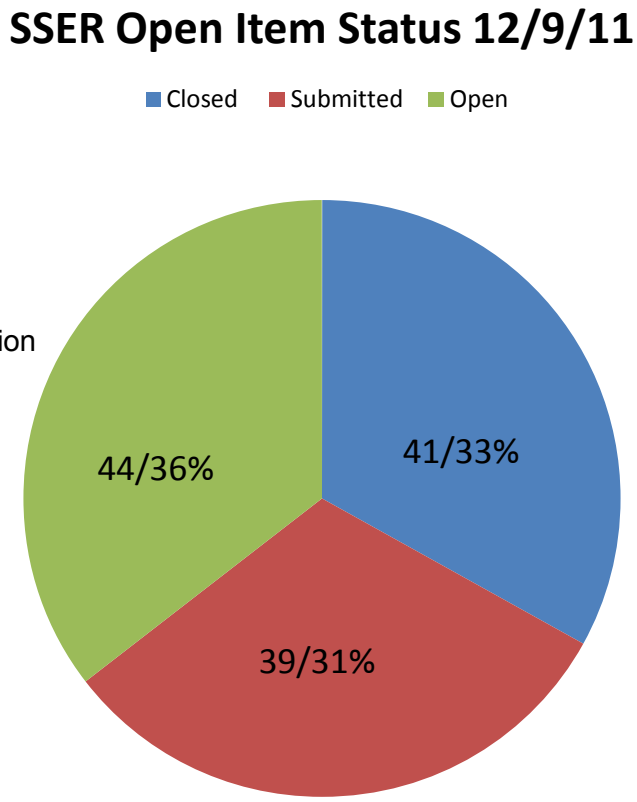
- Management Review Meetings (Oversight by Chief Nuclear Officer (CNO), VP of Operations, Nuclear Safety Review Board (NSRB)
- Permanent Staffing Additions
  - Licensed and Non-Licensed Operators
  - Maintenance Craft
- Training
  - Dual Unit Licenses
  - Unit Differences Training
- Work Management
  - Preventive Maintenance
  - Surveillance Scheduling
  - Functional Equipment Groups (FEG's)
  - Schedule Convergence
  - Refueling Outage Infrastructure after Hot Functional Testing

Transition to Operations

- Procedure Development/Revision
- System Turnover
  - System 30O (Turbine PMP and Space coolers)
  - System 30N (Turbine Bldg Exhaust Fans)
  - System 37 (Gland Seal Water) Complete
  - System 44 (Building Heat) Complete
  - TI-437 Lessons Learned
    - Operations Owns the Turnover Process
    - System Turnover Weekly Meeting for Near Term Systems
    - Turnover of In-Service Systems

SSER (22-25) Open Items





Radiation Protection and Radiation Waste Management
(FSAR Chapter 11 & 12)

Radiation Protection

- WBN committed to ALARA principles
- Shielding features are the same as Unit 1
- Many features are shared between units
  - Labs, Counting Rooms, Access
  - Designed for two unit operation
- NUREG 0737 II.B.2
  - Post accident access and occupancy
  - Updated vital areas to include Unit 2

Radiation Protection

- Radiation Monitors
  - Coverage similar to Unit 1
  - Many Unit 2 monitors are used for Unit 1 Ops
  - 21 new Unit 2 monitors
  - Channel Op Tests extensions to be supported by experience
  - Local CAM previously replaced with portable monitors

Radioactive Waste Management

- Radwaste Systems are shared
  - Operational flexibility to manage releases
  - Condensate demineralizers usually bypassed
  - 100 CFM continuous filtered containment vent
- ANSI N18.1-1984 source term
- Updated Site Specific Parameters
  - 1986 – 2005 meteorology data
  - 2007 land use survey
  - Applied terrain adjustment factors 
  - 50 Mile population dose based on 2040 estimate

Radioactive Waste Management (cont)

- Liquid and gaseous releases
  - Well within regulatory limits
  - Unit 1 used RM 50-2
  - Appendix I for 2 unit operation
  - Cost benefit performed

- Unit 1 operating history
  - Actual releases small fraction of FSAR releases

Chapter 11 and 12 SSER Open Items

- Item 112, 113, 114, 115, 116
  - Update FSAR
  - Completed by FSAR Amendment 105

- Item 135 – Perform Radwaste System Cost-Benefit Study
  - Complete – Cost Benefit submitted

- Item 117 – update FSAR
  - Information previously provided
  - Open

Transient Analysis
(FSAR Chapter 15)

Chapter 15 Transient Analysis

- Unit 2 Analyses Generally Similar to Unit 1 at OL
  - Original Steam Generators
  - No Measurement Uncertainty Recapture

- LBLOCA & SBLOCA have large margins to PCT Limit of 2200^{o}F
  - ASTRUM vs. Appendix K Model

Chapter 15 Transient Analysis

- New Analysis
  - Overpressure Protection on Second Trip
  - CVCS Malfunction that Increases Reactor Coolant System Inventory
  - MSLB Analysis and Parameter Sensitivity Study
- Additional Analyses
  - Inadvertent ECCS – no Liquid Release from PORVs
  - Boron Precipitation
- Open – Boron Dilution Modes 3, 4, 5
  - Same as Unit 1
  - Providing additional information

Radiological Consequences of Accidents
(FSAR Chapter 15)

Accident Dose

- Dose Consequences less than 10 CFR Part 100 and Guidance Document Limits
- Analyses Based on
  - LOCA – Reg. Guide 1.4
  - Waste Gas Decay Tank – Reg. Guide 1.24
  - Fuel Handling Accident – Reg. Guide 1.25 and Reg. Guide 1.183
  - MSLB & SGTR – SRP 15.1.5
  - Loss of AC Power – Conservative Assumptions
  - Rod Ejection – Bounded by LOCA

Accident Dose (Cont.)

- Differences from Unit 1 Licensing Basis
  - Dispersion Coefficients based on 1991 – 2010 Meteorology Data
  - Original Steam Generators
  - No Tritium Rods
  - Dose Equivalent Iodine reduced (T/S value)
  - Fuel Handling Accident based on Alternate Source Term

Questions?

ACRS Subcommittee Meeting Regarding

Watts Bar Nuclear Plant Unit 2

Status of Licensing and Inspection

Docket No. 50-391

December 15, 2011

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Agenda Topics

- **TVA**
  - Construction Completion Status
  - Meteorology and Radiation Protection (FSAR 11 & 12)
  - Radiological Consequences of Accidents (FSAR 15.4)
  - Accident and Transient Analyses (FSAR Chapter 15)
- **NRC**
  - Status of Licensing and Construction Inspection
  - Status of Open Items
  - Supplements 24 and 25 to SER
  - Remaining Safety Review Activities

Region II Presentation of Status of Construction Inspection Activities

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Results of Inspection Program

- Completed 2011 Mid-Cycle review. Overall acceptable performance noted. Three areas highlighted:
  - Inadequate corrective action for historical items (violation with four examples)
  - Resolution of Heinemann circuit breakers
  - No substantive cross-cutting issues
- Twelve (12) severity level IV violations identified in 12-month period. Violations included design control, corrective action, procurement, and procedural compliance issues.
- No escalated enforcement or civil penalties.

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Inspection Program Updates

- RII expended 17,279 staff hours on the project in FY11, an increase from 13,119 hours in FY10. Expect 2012 hours will be similar to 2011.
- Continuing with four (4) WB2 construction resident inspectors
- In addition to the resident inspectors, 41 inspectors performed inspections in 2011
- Four (4) positions in RII (team leader, project inspectors, and project manager) assigned to the WB2 inspection project
- Conducting periodic public meetings with TVA near the site (four meetings held in 2011)

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Status of Inspection Activities

- Approximately 532 construction inspection items in the Inspection Planning and Scheduling (IP&S)
- Closed 154 IP&S items
- Most of the remaining IP&S items have been inspected, but require additional effort to close
- Closed eight (7) Corrective Action Programs and Special Programs, many (8) sub-issues also closed
- TVA's scheduling uncertainties have challenged our inspection planning and staffing allocations

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Pre-Operational Testing Inspections

- Team leader focusing on planning for pre-operational testing inspections
- Two major sections: Testing and Operational Preparedness Inspections
- Lead inspectors assigned to mandatory tests (six) and primal test (nine) inspections
- Operational Preparedness inspections assess management controls and procedures. Examples: radiation protection; chemistry; security; fire protection, etc.

NRR Presentation of Status of Licensing Activities

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Status of Operating License Application

- TVA amendments to FSAR received (A92 to A107)
- 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
- Major Review Areas Remaining
  - Fire Protection Report
  - Closure of open items from SER review

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Status of Open Items

- Total Open Items – 124 (some numbers never used)
- Open Items closed as of SSER 25 – 41
- Of the 83 that remain open
  - Items requiring NRC *confirmation* (e.g., updating FSAR): 43
  - Items requiring additional NRC *evaluation* (e.g., additional information required from TVA to complete staff review): 40

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Safety Evaluation Report Supplements (SSERs)

- SSER 24 Published September 2011
- SSER 25 Published November 2011

Status of Radiation Protection

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Radiation Protection (CH 12)

- Containment Airborne Estimates
- Area Airborne Monitoring in Aux. Bld.
  - Four portable monitoring channels vice fixed
- Area Monitor Operability Test frequency
  - 95% / 95% acceptance criterion
- Descriptions of HP Support Facilities
- Annual Dose Assessment & Vital Area access
- RPM Qualifications
  - Committed to RG 1.8 - 1987

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Plant Effluents (Ch 11.1, 11.2, & 11.3)

Liquid

- S/G tube leakage added to liquid source term to meet concentration limits in 10 CFR 20 and RM 50-2.
  - Above 3.65E-5 uCi/cc : Blowdown processed (CD)
  - Above 3.65E-5 uCi/cc : processed (CD + MD)
  - Less than 3.65E-5 uCi/cc : unprocessed

- Updated calculations of doses from liquid effluents
  - Latest Census and Land-Use Survey
  - Minimal change to 10 CFR 50 App. I doses

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Plant Effluents (Ch 11.1, 11.2, & 11.3)

Gaseous

- Update Plant Configuration
  - Continuous Containment Filtered Venting not 22 Purges per year (Airborne Source Term)
  - Delete Boron Recycle System
- Updated calculations of doses from gaseous effluents
  - Latest Census and Land-Use Survey
  - Critical milk animal & garden locations
  - Meteorology (X/Q, D/Q values), terrain correction
- Staff independent assessment

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Annual Dose per Reactor Unit

	App. I	TVA	NRC
Liquid Effluents			
Total Body (mrem)	3	0.72	0.64
Any Organ (mrem)	10	1.00	1.49
Noble-gas effluents			
Gamma Dose in Air (mrad)	10	0.80	0.90
Beta Dose in Air (mrad)	20	2.71	3.59
Total Body (mrem)	5	0.57	0.51
Skin of an Individual (mrem)	15	1.54	2.60
Airborne Radioiodines / Particulates			
Any Organ	15	9.15	9.75

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RM 50-2 Vs. ALARA Cost/Benefit

- 10 CFR 50 App. I , II.D effluent treatment augmentation cost/benefit analysis
  - Exception for plants with 1974-1976 CPs
- RM 50-2 design criteria fore-runner to App. I
  - Ex.: Maximum Organ Dose - 15 mrem per site (RM 50-2) Vs. 15 mrem per unit (App. I)
- WBN organ dose is 9.15 mrem per unit (18.3 per site)
  - Meets App. I, not RM 50-2

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Reg Guide 1.110 Cost/Benefit Analysis

- Provides a list of radwaste system enhancements
- Annualized costs (capital, labor, operating, & maintenance)
  - Constant 1975 $$
- $1,000 per person-rem saved
  - population within 50 miles of site
- Staff independent analysis
  - Slightly higher doses, slightly lower costs
  - Verified TVA conclusion; no augments warranted

Status of Design Basis Accident Dose Consequence Evaluations

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Major Differences from WBN Unit 1 Licensing Basis

- Updated Atmospheric Dispersion Coefficients
- Original vs. Replacement Steam Generators
- No Tritium-Producing Burnable Absorber Rods (TPBARs) since Unit 2 will not be licensed for tritium production
- Updated Dose Conversion Factors resulted in lower Dose Equivalent Iodine coolant values
- Fuel Handling Accident analyzed for different release scenarios using the Alternative Source Term (AST)

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Off-site dose consequences are low relative to acceptance criteria

- Loss of Coolant Accident (LOCA) doses are “well within” 10 CFR 100.11 values (<25%)
- Main Steam Line Break (MSLB) & Steam Generator Tube Rupture (SGTR) doses are a “small fraction” of 10 CFR 100.11 (< 10%) for both pre-existing and accident generated iodine spike cases
- Control Rod Ejection Accident (CREA) bounded by LOCA; LOCA dose meets the acceptance criteria for CREA, “well within” 10CFR100.11 values (<25%)

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Fuel Handling Accident (FHA) analyzed for three release scenarios

- Closed Containment with credit for filtration using traditional assumptions with whole body and thyroid dose acceptance criteria
- Auxiliary building with no credit for filtration using AST assumptions with Total Effective Dose Equivalent (TEDE) acceptance criteria
- Open containment with no credit for filtration using AST assumptions with TEDE acceptance criteria
- All FHA scenarios meet “well within” (25%) for either 10 CFR 100.11 or 10 CFR 50.67 dose acceptance criteria

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Conclusions

- Design basis dose consequence analyses predict doses within applicable regulatory acceptance criteria
- No open items in the area of design basis dose consequence analyses

Section 15: Transient and Accident Analyses

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Section 15, Transient and Accident Analyses

- **Agenda Topics**
  - Review Procedures
  - General Results
  - Challenging Review Areas
  - Conclusions

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Review Procedures

- Reference the licensing basis of Watts Bar Unit 1
- Ensure that analytic methods are used within the limits of the staff's approval
- Compare results to similar plants
- Additional information was requested to aid in the review of challenging areas:
  - Several rounds of RAIs were issued
  - Additional analyses were requested
  - Two audits were conducted
    - First audit – March 15th in Rockville, MD
    - Second audit – June 28 through 30 in Cranberry, PA

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General Results

- Most results were acceptable w/o further information
  - Analyses performed using NRC-approved methodology
  - Analyses were continually reviewed since the Unit 1 application
  - Results acceptable with margin to acceptance criterion or regulatory limit
- Results for five accident analyses presented some review challenges

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Challenging Review Areas

- 1. Overpressure protection analysis
- 2. CVCS malfunction event
- 3. Inadvertent ECCS actuation at power
- 4. Boron dilution in Modes 3, 4,and 5
- 5. Main steam line break

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1. Overpressure Protection

- SRP 5.2.2 specifies that adequate overpressure protection be demonstrated for the limiting event (loss of load)
- Analysis should be based upon a reactor trip from the 2nd trip signal
- Analysis was based upon reactor trip from 1st trip signal
- TVA re-analyzed the loss of load, assuming reactor trips on the 2nd trip signal
- Results of re-analysis show that RCS and MSS pressure safety limits are not exceeded

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2. CVCS malfunction event

- CVCS malfunction event was not in the FSAR (i.e., it was omitted)
- The event is listed in RG 1.70, Rev 2
- The event is not bounded by the inadvertent ECCS event
- TVA provided an analysis
- Results indicate there is adequate time for manual mitigation

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3. Inadvertent ECCS actuation

- Analysis was unacceptable, as explained in RIS 2005-029
- TVA provided a re-analysis
- Results indicate there is adequate time for manual mitigation

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4. Boron Dilution in Modes 3, 4, and 5

- RG1.70, Revs 0 and 1, required explicit Boron Dilution calculations in Modes 1, 2 and 6. Subsequent revisions RG 1.70 added requirements to consider in all 6 modes
- SRP 15.4.6 calls for analysis of event in all modes
- Analyses inconsistent with SRP since only Modes 1, 2, and 6 analyzed
- Open Item for TVA to provide analyses of boron dilution event that meet the criteria of SRP Section 15.4.6, including
  - Description of the methods and procedures used by the operators to identify the dilution path(s) and terminate the dilution in order to determine analyses comply with GDC 10
  - Time available for manual action begins at start of event

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5. Main Steam Line Break

- Results were too good (compared to similar plants)
- Results were inconsistent with the conclusions of WCAP-9226
- Results were deconstructed, at the 2nd audit, to explain the contribution of each key assumption and parameter
- A new limiting-case analysis was provided

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Staff Review Conclusions

- Staff draws a reasonable assurance conclusion with the same, or higher confidence, as compared to the Unit 1 review
- Some changes in the Unit 2 licensing basis must also apply to the Unit 1 licensing basis
- Westinghouse's steam line break analysis methods should be updated

Project Summary of Watts Bar Unit 2 Remaining Activities

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Project Status

- Staff review nearing completion
- Future Milestones
  - Complete SER and SFES-OL
  - Complete ACRS Review
  - Conduct hearing and ASLB provide decision
  - Operational readiness assessment
  - Certification of as-built construction

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Expectations for Next Meeting

- Scheduled for April 2012
- Fire Protection
- Closure of Open Items