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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

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MEETING OF THE SUBCOMMITTEE ON POWER UPRATES

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THURSDAY,

MARCH 16, 2006

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The meeting was convened in Cabinet/Judiciary Suite of the Hyatt Regency Hotel, Bethesda, Maryland, at 8:30 a.m., Dr. Richard Denning, Subcommittee Chairman, presiding.

MEMBERS PRESENT:

RICHARD S. DENNING Chairman

JOHN SIEBER

GRAHAM B. WALLIS

OTTO L. MAYNARD

ACRS STAFF PRESENT:

RALPH CARUSO

SAM MIRANDA

NRC STAFF PRESENT:

PATRICK MILANO

PAUL PRESCOTT

GARRY ARMSTRONG

ALSO PRESENT:

MARK FLAHERTY	Constellation Power
MARK FINLEY	Constellation Power
JIM DUNNE	Constellation Power
ROY GILLOW	Constellation Power
DAVE WILSON	Constellation Power
GORDON VERDIN	Constellation Power

A-G-E-N-D-A

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

8:30 a.m.

CHAIRMAN DENNING: We are now going to resume, this is the second day of the Subcommittee on Power Uprates of the Advisory Committee on Reactor Safeguards.

And we can immediately move into the next presentation.

MR. FINLEY: Mark Finley, Ginna.

The next piece of our presentation is in the operations and training area. And I'd like to introduce Roy Gillow to cover that topic.

MR. GILLOW: Good morning.

When Mark asked us to give us a brief résumé of our experience, I'm coming on about 30 years of nuclear power, which kind of makes me feel really old. So the 30 years kind of breaks down like this: Six years in the nuclear Navy and 24 years at Ginna. At Ginna I came up through the operations rank: auxiliary operator, control room operator, shift manager. I'm current shift manager and SRO at Ginna.

Today we're going to look at operations, EPU and operations, the human factors, the training that's planned, the overall testing that will go on for the ascension and the special emphasis in large transient testing we plan.

Operations and testing. Procedures we identified, which was 125 procedures that needed changing for uprate, most of these are relatively minor changes, setpoints. However, there's some major procedure changes really identified by the PRA people that had to do with decay heat removal, especially in an Appendix R scenario. Our heat sink and inventory control had to be changed, our procedures had to be changed to enhance the time line. We did this by two ways: Modifications and streamlining procedures.

Also had a few selected EOP changes. We'll go over those that needed major changes. Again, decay heat removal was the major contributor.

Due to decay heat increased from EPU, several actions required more restrictive times for several key actions. As we mentioned, the charging in Appendix R and establishment of aux feedwater for the heat sink where the prime ones.

Procedure enhancements in addition to plant modifications improved these key parameters.

In emergency operating procedures, our function restoration, FR-H.1, which is the heat sink, we had to resequence the procedure to use standby aux feedwater prior to attempting the use of other feedwater sources. Prior to EPU we tried to get condensate grade feedwater to the steam generators. PRA identified there wasn't enough time to do the actions to get condensate grade water, so we went to standby aux feedwater.

Normal shutdown and start up procedures will include additional guidance and resequencing to account for plant modifications, place O-E information in and reduce known operator concerns such as hotwell skewing.

In emergency operating procedures resequencing to use to standby aux feedwater we talked about. Those kinds of things will be incorporate in a training. The training will be a major part of the operations readiness for the post-refueling EPU operations. Operator training consists of classroom and simulator. Classroom training is ongoing with topics such as introduction to EPU, which has already started in fall 2005. Additional topics that have been covered are relaxed axial offset, turbine modifications and licensing changes.

Topics are overall two full cycles of

operator training are planned consisting of 16 hours of classroom and 16 hours of simulator for each cycle.

CHAIRMAN DENNING: What's the status of the simulator? Has the simulator already been modified to be able to --

MR. GILLOW: We're in the final processes of modifying the simulator for EPU. All the changes, modifications will be loaded and our best guess of all the plant parameters will be loaded in.

CHAIRMAN DENNING: And there will be a period of time when the simulator can handle both current and EPU --

MR. GILLOW: Correct.

CHAIRMAN DENNING: -- somehow by --

MR. GILLOW: We'll do some extensive validation on EPU procedures and work on the simulator. AT the same the operating shifts will still be going through the normal plant parameters. The last two cycles the shifts will go through EPU parameters only. But, yes, there will be a certain amount of time where we can use the simulator both for, there will be an EPU simulator and the current plant LOCA simulator

CHAIRMAN DENNING: But at this point you haven't actually done anything with the simulator that would indicate the behavior of the plant with the simulator and the people in training because the simulator just isn't done yet?

MR. GILLOW: We have all the plant -- the final things that are getting loaded into the simulator are best guesses for the behavior of the core. And the simulator in May will be ready for validation and testing at EPU.

MEMBER SIEBER: You're going to have to change some meter faceplates?

MR. GILLOW: Right. For the temporary, for the interim period we're just going to put temporary meter facing with scaling changes. And, of course, the computer will have the correct inputs for that scaling.

MEMBER SIEBER: So to switch from pre-EPU to post-EPU you just take those temporary --

MR. GILLOW: Right. They'll take those temporaries off. Right. Right. They did that when they trained -- they had a contract for a while to train people from overseas, and that's how they handled it with success there.

MEMBER SIEBER: Yes, that'll work.

CHAIRMAN DENNING: We're talking about simulator upgrading modeling will include all major emergency procedure sets. What we're planning in training startup and shutdown, selected functional restoration procedures and abnormal operating procedures.

And the classroom will concentrate on plant modification. We'll do Appendix R walkdown changes. And we'll try to validate all our Appendix R time critical steps when we're doing our walkdowns on Appendix R systems. So we'll get some time lines.

MEMBER MAYNARD: It looked like one of those times for operator action on the Appendix R was like 35 minutes.

MR. GILLOW: Right. Control complex fire 35 minutes to restore charging. That's really what the Appendix or the PRA was talking about. We put two plant modifications in to help relieve that time line and we streamlined our ER Fire 1 procedures to make that the operator makes that time line.

MEMBER MAYNARD: Okay. It looked like or you said that it demonstrated you'd have it done within 30 minutes?

MR. GILLOW: The new number will be like 24 minutes. Currently we're doing in about 24 minutes without the modifications or streamlining the procedures. So we're confident that we'll be well under the 24 minute time line.

MR. FINLEY: Mark Finley. Just to interject, there are two times that I think that were discussed in the safety evaluation. One was 35 minutes, which was to restore aux feedwater for steam generator water and the second time was, as Roy said, to restore charging for pressurizer level. That was the shorter time; 24 minutes.

MR. GILLOW: Yes. The current time to restore charging is like 36 minutes and it's gone to 24 for those reasons that we had to streamline the procedures and provide modifications. And we're confident. We've done preliminary walkdowns. We're going to be well under the time limits with the modifications.

Any questions?

Testing. We're going to do post-modification testing. There's a considerable amount of our applications in. Do our normal low power physics testing.

We're going to do plan a lot of steady

state data reviews. There's a considerable number of stop points in the overall ascension to do state data.

Transient testing and vibration monitor.

One thing that's not listed onto there is the turbine governor belt testing. And we're going to do a 100 percent data review in surveys, that's radiation surveys.

CHAIRMAN DENNING: Before you go any further like me ask you some questions about the performance of the plant under transient conditions, and particularly pressurizer level control.

MR. GILLOW: Okay.

CHAIRMAN DENNING: Because I understand you have experience in this. In the current design at the current level are there any conditions under which you have trouble with pressurizer level control and do you anticipate that at the uprated condition there's some scenarios that are going to be a problem and is it a concern?

MR. GILLOW: Okay. At our current condition our current Tavg is 561. We certainly don't have any pressurized level controls trip or any other -- current pressurizer level band is 35 to 50. And, no, we don't have any challenges there.

I don't expect any on the EPU. Our T average is essentially the T average we had in '96, which we had 573.5. We're going to 574, so it's really a negligible change in no load -- or full load T average.

We did go through to lower pressurizer level on trip, but we had plenty of pressurizer level indication on trip from '96 back. So I wouldn't expect that we'll see any real difference than we saw pre '96 of T average.

CHAIRMAN DENNING: Thanks.

MR. GILLOW: Okay. Transient testing is probably the most operational challenge. Our plant has to do the most benign tests first. The tests we're planning to do is +/-5 percent steam generator level changes. And then after that go into our ramp, a 10 percent ramp change of one percent a minute from 30 down to 20 percent, back to the 30 percent.

My idea when I selected the test was to make sure that the steam generator level system works and then the 10 percent will indicate the rod system is working, the pressurizer level system is working, the Tavg system is working. And that gives you good feeling when you do the trip test. The only thing left is the steam pumps.

Thirty percent test area gives a lot of integration of all the systems, and everything that's been changed with uprate will be tested under these tests, these three tests. And, of course, we're going to do control valve stroking at 46 percent.

CHAIRMAN DENNING: Why not do a turbine trip from operating power?

MR. GILLOW: From?

MR. WOOD: From operating power, the new operating power --

MR. GILLOW: From 100 percent?

MR. FINLEY: We actually have a slide.

MEMBER WALLIS: I think we talked about that.

MR. GILLOW: Yes. The reason that we really thought 30 percent trip, it really gives you more integration of all the systems. When you trip at 100 percent power, the rods go in, everything goes to no low T average. You don't see the integration of the rod control, the steam dumps, pressurizer level as you -- you know, it doesn't really show the full integration of the systems. The 30 percent, really, you got a bigger power mismatch because the reactor doesn't trip. Reactor trips for us at 50 percent on a turbine trip. So you really see a lot more of the system responses than you do if you do a 100 percent trip.

MEMBER WALLIS: On the previous slide you have a step wise escalation of power. Do you have some criteria that tell you when you're satisfied that things are okay and you're ready to make the next step?

MR. GILLOW: Yes. And all the 100 percent power, which is I assume you're looking at this slide here?

MEMBER WALLIS: Yes.

MR. GILLOW: At 85 percent, which is right at 100 percent power, we're planning on 3 percent escalation a day, taking the various data sets vibrations. Then there will be a convening of management meeting that approves the next 3 percent the following day. So we're going to do it in 3 percent increments a day --

MEMBER WALLIS: So it's primarily vibration you're looking for?

MR. GILLOW: That's a huge part of it, but there's also additional data that we're going to take data sets.

Jim?

MR. DUNNE: Yes. This is Jim Dunne.

We're also going to be looking at process conditions in the primary and secondary side of the plant to make sure that the values that we're seeing are consistent with what we expected to see at power level.

MEMBER SIEBER: I presume you're going to be running flux maps at these steps, too, right or are you?

MR. VERDIN: Yes. This is Gord Verdin.

We plan to do pretty much our standard physics testing and power ascension testing. We do have to do a flux map before 50 percent power. We'll do another one at the 85 percent power plateau for incore/excore calibrations.

I'm not certain we'll end up doing flux maps at each one of those plateaus just because we're not really expecting any problems and if the first flux map shows that there's not an issue. So we will obviously. And then we do perform flux maps again once we get to full power equilibrium Xenons.

MR. GILLOW: Any questions?

CHAIRMAN DENNING: So when you say 3 percent a day, that means that in a week --

MR. GILLOW: The final 15 percent will take five full days to accomplish. And, you know, just tying to ensure that we get time to evaluate data, do the vibration monitoring and get full management approve that we're good for another 3 percent power increase. Of course, we have fuel preconditioning in there, too, that's slow anyway.

MEMBER MAYNARD: Well that'd basically be your minimum time, right?

MR. GILLOW: Right.

MEMBER MAYNARD: I mean if any issues, questions or anything come up --

MR. GILLOW: Right. IF anything doesn't meet acceptance or criteria, then we're going to have to do evaluations on whatever.

CHAIRMAN DENNING: When you do this do you have predicted in advance what -- well, let's talk about vibration first.

MR. GILLOW: Okay.

CHAIRMAN DENNING: It sounds like you really haven't determined exactly where monitors are going to be placed.

MR. GILLOW: Yes, they did the walkdown the last week, and that's really what is probably going to be predictive of where we're going to place monitors. Obviously on the main steam and main feed outside containment, I think we're really committed to monitor those heavily. But the other process lines, especially the smaller ones off the main lines, that's going to be determined I think by the walkdown that's been --

CHAIRMAN DENNING: Okay. Now as far as that, how are you going to determine what the level is that is an acceptable level of vibration, for example? I presume that in the power ascension plan there are going to be some criteria. And if you exceed that, then you have to stop --

MR. GILLOW: Do evaluation or do a modification essentially.

CHAIRMAN DENNING: -- and do an evaluation? Yes. How are you going to determine what that level is on vibration?

MR. FINLEY: This is Mark Finley, Ginna.

We plan to do both visual inspections and handheld accelerometer type data collection. And we plan to use the criteria consistent with, I believe it's OM-3 code and apply that. Using the visual inspections we will look for a displacement that exceeds one eighth of an inch. And if we have anything that exceeds one eighth of an inch, we will evaluate that further.

CHAIRMAN DENNING: There is a standard, you say, that applies to this?

MR. FINLEY: Yes. There is an operating standard that applies to this.

CHAIRMAN DENNING: And this is something that's recognized by the NRC?

MR. MILANO: Yes, it is. Yes. The operations and maintenance code would then within ASME. And it's OM-3.

MR. GILLOW: Any questions?

MEMBER WALLIS: Is it possible to have pressure fluctuations of sort of the organ pipe type that doesn't really lead to much displacement of the pipe but there's a considerable amount of pressure fluctuation in the pipe itself: It's playing a musical note very loudly?

MR. GILLOW: I assume you're talking like resonance?

MEMBER WALLIS: Yes, that sort of thing. Yes.

MR. GILLOW: When we have resonance, we usually hear. You get a visual, an audio --

MEMBER WALLIS: So what's your threshold for --

MR. GILLOW: I don't know if we have a threshold, but we're certainly planning walkdowns that would recognize that we have a resonance problem.

MR. DUNNE: This is Jim Dunne.

Basically, you know, the operations staff as they do walkarounds on a daily basis pretty much know what the normal noise levels are. And if all of a sudden they start hearing noise levels that are different, they usually let engineering know about it, write a condition report and force us to go out and assess it and determine whether there are any concerns with it.

So if there were obvious changes in the noise levels, the operations staff would probably pick that up in their walkarounds. And, hopefully, the engineering walkarounds for the visual vibration would also pick it up. And that would be something that would be noted on the walkaround. And then we would have to evaluate what it meant going forward as to whether we thought it was an issue or not.

MR. GILLOW: Okay. I think we've handled that through our standard technical evaluation process.

MR. DUNNE: Yes. For example, a couple

of years ago we changed an internal feed reg valve. And coming out of that outage the noise level emanating from the valve was different than what operations was used to. So they wrote actually a condition report to engineering for us to evaluate to determine whether we thought there were any adverse consequences due to the new noise level. It was about cavitating madly and there was a potential for cavitation down the stream to the valve.

CHAIRMAN DENNING: Would you have a limit, for example on moisture carryover?

MR. DUNNE: WE're not going to monitor moisture carryover. To do moisture carryover in a-- unlike a PWR or a BWR, we can use the primary site isotropic composition to assess moisture carryover. We don't really have that on the PWR to do that. We have to do a special test. Typically those tests are very time consuming and require a lot of planning. Usually it's a sodium 24 tracer test, which has a relative short half life.

So, for example, when we did steam generator replacement in 1996 we did a moisture carryover test as a performance warranty type of test because of the aggressive design requirement we had on moisture carryover. We went from .25 percent with the original generators down to 0,1 percent and we wanted verification that these new separators were actually doing that. So we did do a moisture carryover test.

Now the actual setting up the procedures and coordinating the logistics and getting the sodium tracer isotope in from a university in Missouri and getting into the plant basically was a very involved process. It took us about three months after we came up before we were ready to do the test.

Based upon the full scale model testing that B&W Canada has done on their steam separator modules, we're well within the bounds as to what they have tested these units at. And since our visual moisture carryover test from the replacement generator basically showed results better then and are equal to what their laboratory results showed, we feel reasonably confident that moisture carryover values will be consistent with what their full scale testing. And there's no need for us to go in and do a moisture carryover test, per se.

MR. MILANO: Mark, you know yesterday you talked, maybe it would be good to reiterate what you talked about yesterday in terms of your baseline testing for both displacement in vibration and stuff like that as a precursor to having a baseline level at your current 100 percent and so that to evaluate or correlate against as you go up to the new 100 percent.

MR. FINLEY: Right. Mark Finley, Ginna.

Yes. Roy had mentioned we did a baseline walkdown two weeks ago and we're in the process of evaluating that data. We'll come up with a set of inspection points for the handheld accelerometer taking based on that baseline walkdown. And we'll also develop our complete list of visual inspection points on that walkdown as well.

MEMBER WALLIS: I guess you've finished your presentation?

MR. GILLOW: Yes, I think --

MEMBER WALLIS: Could I go back to the boron precipitation measure? You said you made some modifications to the emergency operating procedure?

MR. GILLOW: We know we have to make modifications to --

MEMBER WALLIS: Right. Right.

MR. GILLOW: -- procedure. We haven't completed those consistent --

MEMBER WALLIS: This is long --

MR. GILLOW: -- we don't know -- all the ramifications of boron precipitation.

MEMBER WALLIS: This is long term cooling.

MR. GILLOW: Right.

MEMBER WALLIS: And you have to meet some criteria in parts per million or something like that and you have --

MR. GILLOW: There will be some unit that we have to provide upper plenum injection.

MEMBER WALLIS: Right. Some sort of quantitative analysis that has some criterion for success in terms of parts per million or some measure?

MR. MILANO: This is going to be part of our discussions when --

MEMBER WALLIS: So you're going to discuss this?

MR. MILANO: We're going to discuss this on April 27th --

MEMBER WALLIS: Oh, April 27th. Okay.

MR. MILANO: This is part of -- we're going to be discussing three things.

MEMBER WALLIS: Okay. Because I was interested in your reaction to this and your evaluation of the boron precipitation.

MR. MILANO: We're still not --

MEMBER WALLIS: Next month? Okay.

MR. MILANO: Yes, indeed.

MEMBER WALLIS: Okay. Thank you. All right.

MR. GILLOW: I think we pretty much have gone everything that I had. So if there's on other questions, I'll introduce Mark Flaherty, Nuclear Technical Service.

MR. FINLEY: I think before we --

MR. MILANO: We're a little ahead, so what I'd like to do is rather than we've got our human factors people that were going to talk after the break, I'd like to do that first and then if there aren't a lot of questions, maybe we'll go right into related to power ascension and testing.

I'd like to introduce Garry Armstrong. Garry's. Garry's from our operator license and Human Performance Branch. And he's one of the Human Factors Engineers.

MR. ARMSTRONG: Again, my name is Garry Armstrong, and as Pat said, I'm a Human Factors Engineer. And we review the human performance aspects of the Ginna EPU.

Our areas of review that the human factors folk look at are the programs procedures, training and the human system interface design features that are related to the operator performance. And the purpose of the review is to assure that the operator performance is not adversely affected by the proposed EPU.

The regulatory criteria, as you see listed there, many parts of it come from the Review Standard, in which our areas fall under Matrix 11. There are five areas that I will discuss later on in the presentation. And the other regulatory criteria is 10 CFR 50.120, 10 CFR Part 55, the Generic Letter 82-33 and the Standard Review Plan Chapter 19.

And the five areas that are listed in Matrix 11 that we will discusses the changes that are related to are:

The emergency and abnormal operating procedures;

The changes for operator actions related to the uprate;

The changes to the control room alarms, controls and displays;

The safety parameter display system. I'll refer to that as the SPDS, and;

The operator training programming and control simulator.

The first area, the emergency and abnormal operating procedures, we identified three major changes to the procedures that we looked at as far as the EPU. As Roy discussed earlier for Ginna, they were going to streamline some procedures. The main portion to streamline was going to come in the E-O procedures, which is the standard post-trip actions that the operator must take -- sorry.

And what that is doing is that the automatic verification steps that are related to the ECCS injection, those steps are going to be relocated into an attachment in which a licensed operator will perform those verification tasks in parallel to the majority of the E-O procedure that will be performed. Basically this will help the operators to expedite through the E-O procedure faster so that they'll be able to identify the accident condition and get into those procedures much faster. And this, like Roy said earlier, that will just offset the effects of the increased decay heat. So they're trying to build in more time for the operator to be able to handle those other mitigation tasks.

MEMBER MAYNARD: Is this change unique to Ginna or is this a fairly standard change that a number of the Westinghouse PWR plants have made to E-O?

MR. GILLOW: Yes. This is a MOG initiative that many other plants have already gone to this attachment.

MEMBER MAYNARD: Because I think that this would be an applicable and beneficial not only for EPU, but for even non-EPU conditions. I didn't think this was unique. You weren't out on your own writing E-O changes?

MR. GILLOW: That's correct. This is Westinghouse Owners Group.

MR. ARMSTRONG: All right. And that seques into the next procedure change that we identified that would benefit from the revised E-O, and which Roy mentioned earlier, the functional restoration procedure in which the operator would initiate the standby auxiliary feedwater once the normal auxiliary feedwater cannot be established. And this is related to the high energy line break accident.

And finally, as discussed yesterday, the plant modifications related to the Appendix R events will also be reflected in the procedure to enhance the operator actions -- I mean the effectiveness of the operator actions in those scenarios.

And all three of these areas, the training for all three of these procedures will be implemented prior to EPU.

Moving on to operator actions sensitive to a power uprate, in identifying the changes that the licensee submitted to us, mainly these are just the areas that they identified that would have some effect due to the increased decay heat. But overall, there was minimal effect as far as any new actions being introduced and any real times that will be different from the times that they're already achieving in their response times.

And example, jumping out to the third bullet here. And we got into a little discussion about this earlier in which one of the Appendix R events would cause the dryout to be reduced from 50 to 35 minutes. And in our discussions with the licensee the operator has already been able to achieve establishing feedwater flow within 30 minutes. And so with the enhancements that they're making to the plant as well as the procedure changes, they will basically just ensure that they would make it faster than the 30 minutes and will not take anymore than the 30 minutes needed.

MR. CARUSO: That change in the steam generator dryout time seems much larger than would be expected from a 17 percent power uprate. Do you have any idea why it went from 50 to 35 minutes?

MR. ARMSTRONG: From our understanding, that would be due to the increased effects of the decay heat.

MR. FINLEY: This is Mark Finley.

You're correct, that changes a greater percent than the 17 percent change in decay heat. This is just a more conservative analysis that we've done to establish the 35 minutes for EPU.

MEMBER WALLIS: But realistically it's going to be more than that, isn't there? The dryout time is going to be 40 something, realistically?

MR. FINLEY: Oh, that's correct. This is a conservative analysis. We would expect the dryout time to be longer than the 35 minutes.

MEMBER WALLIS: I just wonder why you went to the extreme of being so conservative when you used 50 before. Was that conservative, too, or 50 was not conservative?

MR. GILLOW: Fifty was conservative.

MEMBER WALLIS: So you're even more conservative now.

MR. GILLOW: Well, you have the decay heat; that's going to drive it down some.

MR. DUNNE: In addition to the increased decay heat, which will steam water off faster from the generator, your initial water inventory for the generator is a bit lower because of the change in the circulation ratio. So you've got a slight decrease in initial water inventory due to EPU at full power and then you have the higher decay heat. So both of those would cause your dryout time to, obviously, move forward to an earlier time.

MR. ARMSTRONG: All right. Moving on. As discussed earlier, the functional restoration procedures is only interested on which the operator action is done earlier in the procedure to basically initiate the standby AFW flow. All right.

MEMBER WALLIS: Well, I'm surprised you want to be conservative about steam generator dryout time. Usually a hand calculation using an energy balance does very well in predicting this. If you look --

MR. CARUSO: I have a question, Graham. How much of this had to do with the fact that you moved the feedwater isolation valves closer to the steam generator?

MR. FINLEY: Mark Finley.

None of this change in time had to do with those valves. This is a fire scenario. It's not a steam line break scenario.

MR. CARUSO:

MR. FINLEY: So the feed isolation valves wouldn't be closing here.

MR. CARUSO: I'm sorry to interrupt, Graham.

MR. ARMSTRONG: All the current operator action times will be verified using the simulator and plant with regard to the EPU. And as discussed yesterday, we're still evaluating the operator actions related to the small break LOCA analysis. And that will be discussed next month.

CHAIRMAN DENNING: Is there any reason to think that there is going to be any issue with the small break LOCA or is it just that your review isn't completed?

MR. ARMSTRONG: The review is not complete at this time. Okay.

Moving on. The changes to the control room, alarms, controls and display. In the submittal the licensee provided a listing of the different parameters that would be effected by the EPU. I didn't provide that list here. It's in the SE. And the only new controls that we identified that they were adding were just the two controls for the main feedwater isolation valves. The main areas that the EPU will effect are related to the instrument loops, alarm, response procedures, plant process computer system setpoints and the various controls and control systems as far as their ranges.

The modifications will be completed using the licensee's human factors review as well as the operator's input. And the training on all the modifications will be provided prior to EPU.

For the safety parameter display system, the changes related to the EPU that the licensee identified were the RCA subcooling monitoring to be reduced, the condensate storage tank minimum required level to be increased and the critical safety function status trees to be reviewed and revised. These changes also will be made prior to EPU as well as the training.

And the last area, which relates to operator training and the control room simulator, the training will typically cover the plant modifications related to EPU as well as the procedure changes, the startup test procedures and the parameters and the setpoints and everything that would be revised in the control room. Again, the training, the simulator training will be implemented prior to EPU. The simulator itself will be validated against the inspected EPU responses and the data from the startup tests.

The simulator fidelity will be implemented in accordance with ANSI/ANS 3.5 1998 using the RETRAN program.

And as discussed earlier, the Appendix R procedure changes involving the local manipulations will be validated using the walkthrough simulations in the field.

So our conclusion is that the Staff has accounted for the effects of the proposed EPU on the available time for operator actions and that they have taken or will commit to take the appropriate actions to assure that the operator performance is not adversely affected by the proposed EPU.

The license continues to meet the applicable NRC requirements related to human performance.

and we find that the proposed EPU

related to human factors acceptable except for, like I say, we're still reviewing the small break LOCA portion.

Okay. That's all I have. Any questions?

CHAIRMAN DENNING: No. Thank you very much.

MR. ARMSTRONG: Okay.

MR. MILANO: I think it's best if we just continue right now.

CHAIRMAN DENNING: Absolutely. Yes.

MR. MILANO: I'd like to Paul Prescott. He's from our Quality Assurance and Vendor Branch. They have the full blown responsibility for evaluating the power ascension and testing programs.

MEMBER WALLIS: Is there any guidance about this, power ascension and test program for PWRs? I think in the BWR case GE has a guidance in their power uprate. Is there some guidance for PWRs that states what sorts of tests are expected? Is there a work guidance or an Agency guidance or anything like that?

MR. PRESCOTT: Good morning.

MR. MILANO: Well, no. He's asking a question as to whether -- before you get started in your presentation as to is there industry or vendor guidance that's out there that would tend to give you the basic principles of what's needed for a PWR power ascension test?

MR. PRESCOTT: No. Unlike GE which had ALTA01, which supplied very specific guidance on what was required for what they possibly considered was necessary for large transient testing, the WCAP produced by Westinghouse does not have any such guidance in its document. Okay.

Well, good morning. My name is Paul Prescott. And myself along with Aida Rivera-Varona from the Quality and Vendor Branch performed the review of Ginna's proposed power ascension testing.

As was stated by Pat, the Quality and Vendor Branch has overall responsibility for the review. EQVA has overall responsibility for the test program review along with the secondary review branches that verify that their respective system structures and components perform satisfactorily in service.

As you're well aware, we looked extensively at plant modifications and proposed testing and the effects on normal operations as well as abnormal operating occurrences.

I won't go into a lot of detail about the guidance of SRP 14.2.1. As you may recall, it was only about a couple of weeks ago I was before you gentlemen for a few hours discussing this review that we do.

And I just want to say I appreciate Mr. Denning's input that we're looking at that right now for possible input into the guidance that we do.

So as the next slide shows, we looked at operator training, as was just described by the gentleman that was just up here, but we take another look at it from an overall perspective.

We take a look at the modifications that were performed in the post-modifications that are proposed by the licensee. We also do a secondary analysis that the codes were looked at by the licensee and also by the Staff and the emergency operating procedures that are proposed.

As you're well aware, the burden is on the licensee to provide adequate justification for all the Staff's areas of review. Other Staff considerations are reduction in margin of safety, vendor topical reports, we just discussed, and risk implications.

The Staff did consider Ginna's response

to the RAIs and their overall response to the SRP to be quite comprehensive.

As has been discussed already, Ginna proposes to do a transient test, I won't call it a large transient test, but a transient test to gain a data point on the integrated plant response and that the control system achieve a stable plant condition following the transient that they plan to put on the plant.

The big ticket items that they plan to look at are pressurizer level and pressurizer control, the steam generator level control, steam dump control and rod control, as has been discussed.

MEMBER WALLIS: Excuse me. When they do this 30 percent power trip, is there a large quantity of steam bypassed to the condenser?

MR. FINLEY: That's correct. Approximately 20 percent.

MEMBER WALLIS: Twenty percent.

MR. FINLEY: Yes.

MEMBER WALLIS: So you don't try to sort of handle it all with the reactor system. You let the steam go and --

MR. FINLEY: That's correct.

MR. GILLOW: That's part of the idea is

to set the steam flow system and controls --

MEMBER WALLIS: Right. Right. Right.

MR. GILLOW: -- integrated with the rod controls.

MEMBER WALLIS: And there has to be some synthesis of all these things together?

MR. GILLOW: That's correct.

MEMBER WALLIS: Right.

MR. GILLOW: And that's really --

MEMBER WALLIS: That's what you're testing?

MR. GILLOW: That's right.

MR. PRESCOTT: And if I'm not mistaken, one of the requirements for a successful test is that the reactor doesn't trip, is that correct?

MR. GILLOW: Right. That's a high level acceptance criteria.

MR. PRESCOTT: Right. That should be a high level acceptance criteria.

MEMBER WALLIS: Well presumably if you just dumped all the steam, you just keep going and keep dumping steam --

MR. GILLOW: Well, the rod control system would bring the temperature back and the steam dumps will shut off. That's really --

MEMBER WALLIS: Yes, that's right. That's what you have to do.

MR. GILLOW: Yes, right.

MEMBER WALLIS: But I mean you could just keep dumping steam for a long time.

MR. GILLOW: Well, the integrated system we'll stop dumping.

MEMBER WALLIS: Will stop that?

MR. GILLOW: We actually will keep dumping steam because we're going to stop at 12 percent reactor power.

MEMBER WALLIS: Yes.

MR. GILLOW: To create a positive MTC. We don't want to get close to going out of power range.

MEMBER WALLIS: Yes, to shutdown. Right.

MR. GILLOW: And then once we stabilize, we can go ahead and reascend and resync on line and go back to 30 percent level.

MEMBER WALLIS: I don't know, you don't have it here, but it would sort of help if you would indicate sort of a simulation of this. I mean, just to have one picture or something of what happens to the steam generator.

MR. GILLOW: I actually have it in my slides.

MEMBER WALLIS: What happens to the pressurize level. Yes. Maybe next time or something, or you can do it now.

MR. GILLOW: Well, I just got to satisfy the --

MEMBER WALLIS: Show that there are significant events happening that are challenging things.

MR. GILLOW: Right. That's correct.

MR. FINLEY: Okay. Mark Finley. Hopefully this will give you some sense. That first slide at the top there shows nuclear power and turbine load as a function of time. And, obviously, initially there will be a rapid transient for turbine load and that's creates the fairly large power mismatch. And what's operating at this point is the steam dumps will be opening and rods will be driving into --

MEMBER WALLIS: Can you show us what the pressurizer does?

MR. FINLEY: I think I have that in the next slide. You can see before I go to the next slide, average coolant temperature starts out increasing and then will decrease to a controlled value.

And then for the pressurizer, we have pressurizer pressure there and pressurizer level. Pressurizer pressure increases initially due to the average coolant temperature rise that I showed on the previous slide, about 30 points is what we predict. A little more than that.

MEMBER WALLIS: So the pressurizer level doesn't change all that much, because there's a zero somewhere down below?

MR. FINLEY: That's correct. The pressurizer level, we don't expect to go up more than a couple of inches there. I'm sorry. That's a couple of percent.

MEMBER SIEBER: This is at a higher power level than you'd --

MR. FINLEY: That's correct. This is at 30 percent, and this is the delta that we'd see that.

Now for --

MEMBER WALLIS: You have a RETRAN prediction of this or something like this you show here, and you're going to see if it does what you expect it to do, right?

MR. FINLEY: That's correct.

MEMBER WALLIS: Right.

MR. FINLEY: That's correct. This is actually LOFTRAN, but --

MEMBER WALLIS: It's LOFTRAN.

MEMBER MAYNARD: And would your results be factored into any simulator modeling for future training also?

MR. FINLEY: That's correct. And the simulator.

MEMBER WALLIS: Well, I'm very glad you had the backup slides because it's nice to see sort of substance, not just words. Thank you very much.

MR. PRESCOTT: As we discussed a couple of weeks ago, we have accepted justifications to now performing large transient testing. And Ginna did not have any, after review of their modifications and the proposed testing program as compared to their initial test program, there were no outliers that points towards indications that large transient testing was needed for code verification. They had operating experience from Kewaunee. Kewaunee is currently at a similar power level that Ginna will reach from this EPU. And that was gone over with the licensee.

And as I said, their test program monitored sufficiently the plant parameters that are expected to change from the EPU.

So in summing this up we found that the test program that the applicant proposes was quite comprehensive. They actually were the ones that proposed the 30 percent transient test that they're going to impose on the plant to verify the integrated plant response is adequate. And the Staff had no outstanding issues concerned with the test program.

CHAIRMAN DENNING: Did you look to see what LOFTRAN results would have been for a trip from 100 percent to get a feeling as to what the different challenges were to systems and total system response? I mean, we've seen here a good example of what the expectation is for the 30 percent manual trip.

MR. MIRANDA: This is Sam Miranda from Reactor Systems and NRR.

That's the loss-of-the-electrical load reported in Chapter 15?

CHAIRMAN DENNING: Yes. Okay. So that's exactly what it looks like if we could look all of the system response in that -- I mean, I wanted to look at the transient system response. So if we look at that particular accident --

MR. MIRANDA: Yes. Yes, you can find it in the licensing basis in the FSAR Chapter 15. And there's also an analysis in the applicant's license amendment request.

CHAIRMAN DENNING: Thanks.

MEMBER SIEBER: But that would be quite different than --

CHAIRMAN DENNING: Than this?

MEMBER SIEBER: Because the reactor would trip and everything would basically try to shut down.

MR. GILLOW: That's correct.

MEMBER SIEBER: As opposed to this kind of a test --

MR. GILLOW: Yes. This shows the system is really operating.

MEMBER SIEBER: -- 30 percent where anything modulated.

MR. GILLOW: Everything goes to the no load and you're really just as the mercy of how much decay heat you have as far as steam valves or --

MEMBER SIEBER: That's all you're doing is dumping steam and --

MR. FINLEY: This is Mark Finley.

In addition to the Chapter 15 accident analysis that Sam Miranda mentioned, we also did a more realistic LOFTRAN simulation of a trip from 100 percent power just to give us a more realistic feeling for what the control systems would do.

CHAIRMAN DENNING: Oh, yes. The difference is the one is a regulatory analysis and the other is a safety analysis?

MR. FINLEY: That's correct. And the safety analysis doesn't credit action for non-safety related equipment; spray for example.

MEMBER SIEBER: When you think about it, a loss of load at 30 percent basically simulates how the rest of the plant would operate if only DKE were a contributor. And so the results you get are roughly the same as a trip from 100 percent as far as system response is concerned.

MR. GILLOW: Right. No, the difference would be your rod control system will just go in, it integrates back in and you'd close your steam valves.

MEMBER SIEBER: Right. You're just getting the heat from a different source.

MR. GILLOW: Right.

CHAIRMAN DENNING: With regards to the power ascension scheduling, is there past history of similar uprates and how did the scheduling look like there? I mean, like the three percent increase per day, is that typical?

MR. PRESCOTT: Right. That's --

CHAIRMAN DENNING: Or are people taking longer?

MR. PRESCOTT: No, that's pretty standard. I would say I was the senior resident at the Duane Arnold when they did their power uprate, and this pretty much models what they did for their power ascension and their levels of power that they would go to and stop, and essentially baseline there before they would move to the next level to get data. So this was typical.

MEMBER SIEBER: This actually looks like a startup test for a new reactor.

MR. PRESCOTT: Right. Very similar.

MEMBER MAYNARD: That's where you took it from, mostly?

CHAIRMAN DENNING: What's the resident inspector's role in this? I mean, obviously he's there, but does he get involved at all in the decision as to whether criteria have been met or not and the next day's power ascension?

MR. PRESCOTT: At the time that I was the senior resident, they did not have a specific inspection procedure on how to conduct how we should -- it wasn't spelled out how we should perform our function there. However, since that time it was obviously deemed wise that we develop something. And it has been developed. Now the specifics on that procedure, I can't really speak to you. But I can tell you that either my resident or myself were there for the entire time just because, as you know, Region III had at the time a differing professional view that was put forward. And so therefore, there was a lot of interest on power uprates, especially in Region III. I can speak specifically for Region III.

But even though we didn't have any specific time cut out for it, we made time to observe the entire power uprate.

MR. MILANO: I'd like to also bring in there, I've been having discussions with our Region I staff. And Region I plans to supplement the resident inspector staff during the power ascension testing. As Paul indicated, there is inspection manual guidance now on power ascension testing. And in each one of the plateaus, even though it's not a hold point in terms of the NRC, there is an expectation that once the licensee makes their determination that they've met their objectives and they plan to go up to the next power level, that there will be a discussion. And there also is an expectation that the supplemental NRC inspection staff will then relay the information back to both NRR and also to the regional management and basically just concurrence with the fact that they're going to go up to the next level.

MEMBER SIEBER: On the other hand, the licensee has sole responsibility for the operation of the station.

MR. MILANO: That is correct.

MEMBER SIEBER: And they would step in if there's a violation of license conditions, technical specifications or commitments, but not detailed manipulation of the controls. The only ones that are licensed to do that are the plant operators.

MR. MILANO: In all reality, assuming that they've met their test objectives, what we're going to be probably interested in and want to have discussions with is if they see something that's somewhat abnormal, let's say they start seeing a higher vibration but they assess it to be adequate, we'll probably want to, you know, just to make sure that we're comfortable with it even though it's not a violation of anything, any code limits or anything like that.

MEMBER SIEBER: Well, the interesting thing it depends on the component when you're talking about vibrations. Things like throttle valves and regulating valves are quieter at full power than they are when they're partially closed. The rotating machinery usually is its nosiest when it's running flat out. The sound of the plant changes depending on what power load you're at.

MR. PRESCOTT: Thank you, gentlemen.

CHAIRMAN DENNING: Thank you.

MR. MILANO: Well, that concludes the presentations that are expected of the NRR staff.

I'd like to turn it back over to Mr. Finley who is going to wrap up the licensee's portion. And then after that, we can discuss anything that came out of the last day and a half.

MR. FINLEY: Mark Finley.

I'd just like to introduce Mark Flaherty once again to conclude for us.

MR. FLAHERTY: Okay. I've got a couple of points up here in a slide to kind of summarize what you've heard over the last day and half and then also I have a couple of other points I'd like to make.

There's been a lot of detailed and comprehensive reviews with respect to this project, and this includes both from a risk perspective and regulatory perspective.

To bound this a little bit, I've done both for Ginna Station. I created the original PRA model and I did all the PRA work originally. I've also done accident analysis work for Ginna. So I'd like to provide a little perspective from that from that you've heard.

The accident analysis discussions from yesterday is really a regulatory focus. And those are driven by establishing a limit, whether it DNBR or pressurizer pressure or whatever it may be and then running the code assuming that all non-safety related items are maximized and utilized, whatever, to maximize the effect on that. Let's say charging flow, your spray control, that type of thing are basically turned off if you're looking for DNB parameters such that you want to force the computer code to assume that worse case conditions actually happened.

MEMBER WALLIS: So this is no credit for a non-safety related systems?

MR. FLAHERTY: Correct. In accident analysis space since it's regulatory driven --

MEMBER WALLIS: Because in the real sort of PRA type of space.

MR. FLAHERTY: Yes.

MEMBER WALLIS: I would hate to say PRA is real, but in a more real space those things would be available?

MR. FLAHERTY: Correct. And that's the delta that I wanted to discuss a little bit, is that from the accident analysis code if we're looking at it for DNB, we'll assume that a pressurizer spray does not work so that RCS pressure and temperature goes to extreme and then challenges DNB. Okay. And we also do not credit operator actions, per se. We'll typically take a hit for a ten minute delay for operator actions.

So looking at the EOP enhancements, whatever else like that, most of those are driven by the risk side of the house versus the regulatory computer codes.

Well, the regulatory accident analysis aspects did drive some modifications to the plant. That's the main feedwater isolation drive which is driven by steam line break. The content storage tank level inventory. So running the accident analysis computer codes did drive physical plant modifications for the site.

MEMBER WALLIS: And then in one case you didn't like the results, so you used a different method.

MR. FLAHERTY: Well, I want to discuss that a little bit also. And I'm going to use an example here for feedline break in accident analysis space, regulatory space. That the computer codes do not address the cool down effect once you exposure feedring. So once you expose the feedring, you're going to get steaming effect out the break. The computer code doesn't address that because you're looking at DNB, and so therefore you want to maximize the heatup of the primary system. So when you start looking at this and we tried to simulate this on a the simulator to reflect that, it becomes very difficult because a simulator is going to show that once you expose that line, you're going to get the cool down effect. So from a regulatory perspective when you saw from yesterday the limits that were very close or right at the DNB limits, in many cases that's, you know besides the conservatisms embedded in the code, is conservatisms in the parameters, whatever else, as you're modeling that.

On the opposite side from a PRA perspective, you know your comment that PRA is not real, whatever else, PRA does try to reflect what we really think is going to happen. Okay? And so I've avoiding the word "realism," but it tries to reflect what we really think is going to happen.

MEMBER WALLIS: Yes, I think it would say that I think it's an honest attempt to be as really distinct as you can, but then you shouldn't believe that it is totally realistic.

MR. FLAHERTY: You need both sides of the equation. You need the regulatory or deterministic side, but you also need a PRA to give you the opposite perspective. And we did use the PRA to optimize EOP actions. You know, it was recognized that in the FR-H.1 procedures, as Roy discussed this morning, we're putting a step early up front that recognizes that hey if you know for a fact that you've lost all preferred aux feedwater, jump immediately to standby aux feedwater rather than trying to recover main feedwater, etcetera, from the secondary side.

So that's from the PRA side helped drive that this was probably the appropriate decision to make.

So hopefully that puts that in perspective. I know we'll be discussing small break LOCA and the boron precipitation at next month's meeting, but I did want to explain that there are two distinct sides that both us as the licensee and the NRC we tried to recognize those and factor those into the power uprate itself.

MEMBER WALLIS: Well, I think that sort of level of perspective is very useful to this sort of a Committee so we don't get lost in all the details.

MR. FLAHERTY: Yes.

Now the next bullet discusses that no safety issues were uncovered. And what I just discussed I think hopefully reenforces that.

Comprehensive testing will be performed. What I want to bring up for here is that I'm in corporate offices in Annapolis. And the project team itself, and especially operations came forward with the proposed for the 30 percent trip test. And the reasons as we were discussing this morning, is primarily that they want to test a full integration of all the systems. And so they came forward saying that we want to do this. And they made that presentation to site senior management and corporate management and we agreed that, yes, that was the appropriate decision to make and it came from the operations and the project team as this is the right thing to do.

So I wanted to emphasize that. And then, you know, obviously discussions with the NRC as part of the review and, hopefully, approval of the project reenforced that, yes, this test integration, whatever else like that, is the right thing to do.

And then lastly, that Ginna safety and reliability will be maintained throughout the plant modifications, procedure changes and training. And we heard this morning, you know you were asking some questions. What happens for vibration if you start seeing it, that type of thing. The station does have established programs in place to deal with this type of stuff. And they are going to be reenforced as part of the power ascension testing.

For example, we have what's called an

IRT, an issue response team. And that's standard practice within Constellation and implemented at Ginna. And we utilize this process at all times, but as with respect to power ascension testing if vibration issues are identified in the field, whether it's by operations or by the team doing inspections or whatever it may be, it gets entered in the corrective action process and then it gets turned over to this IRT which is comprised of knowledgeable SMEs dealing with this specific topic And there is significant corporate oversight.

Now, the station probably --

MEMBER WALLIS: Corrective action program doesn't have an enormous backlog of things?

MR. FLAHERTY: Well, that's what the whole purpose of this IRT is, is that when an issue of significant importance, as power ascension testing and vibrations and whatever else it would come out to be, it automatically gets dumped into an IRT which is a part of the corrective action process but immediately says this is a significant issue that we are going to look at with a dedicated team, the highest priority. And so operations, engineering, whatever is involved with that and there is significant corporate oversight.

Now, the site doesn't like the last aspect, you know, because corporate we can always ask the questions and say what if, that type of thing. But this is an established process that most utilities actually implement.

So I guess that's all I would like to say. And we appreciate the opportunity to meet and discuss with you.

CHAIRMAN DENNING: Very good.

First, let me say I think that you guys made excellent presentations from both sides of the table here. And I'm not aware of any significant issues that have come up of the discussions we've heard today. Obviously, the role of the Subcommittee is just to take information to the full Committee and it's the full Committee that deliberates and makes decisions.

As far as the next meeting is planned, let's talk a little bit about that.

Ralph, how much time do we have set aside for --

MR. CARUSO: We have three days at the end of April to cover Beaver Valley and the open items that are left with regard to Ginna, which are small break LOCA, boron precipitation and long term cooling. And I think I had originally planned to do Beaver Valley two days and then finish Ginna. So we have a whole day allocated.

CHAIRMAN DENNING: I doubt that we need a whole day. Is that your feeling?

MEMBER WALLIS: Why do we need two days for Beaver Valley. I mean, we did this in about one day.

MR. CARUSO: Well, Beaver Valley, hopefully, will also do LOCA and long term cooling.

MEMBER WALLIS: They'll do everything.

CHAIRMAN DENNING: They'll do everything.

MR. CARUSO: Everything.

MEMBER WALLIS: I think we need half a day. Half a day will be fine. As long as everyone has everything ready.

MR. CARUSO: Half a day for --

MEMBER WALLIS: For Ginna.

MR. CARUSO: For Ginna.

MEMBER WALLIS: To wrap up Ginna.

MR. CARUSO: Okay.

CHAIRMAN DENNING: Yes. And, Jack, so you have any comments about that?

MEMBER SIEBER: I agree with you that

both the licensee and the Staff have done a good job in preparing the documents for the EPU and putting together these presentations.

I asked a question yesterday that perhaps I didn't ask it right, I still have a thing that concerns me, and were I Dr. Kress I would take a Magic Marker and write right on the screen so that I could illustrate my point.

But when you're deciding operating parameters and how you will set your tech specs, you do an analysis and that describes in my way of looking at it a series of limits. You can't let TH go any higher than this, and Tavg can operate in this band, and you can't get any lower than this in that band. And then the plant folks describe where they actually want to operate the plant, which is usually somewhere in the middle of this box of limits. So that as the plant undergoes transients you don't hit a limit in the plant trips or you don't close to some safety limit or something like that.

And when I looked at that and in the application I looked at this table of what the limits really were, and one of this was T_{Hot} and it was up around 617 degrees for the limit, and then I looked at your chart which you showed us yesterday of where you planned to operate the plant and it was something like 609, which is more modest and probably in the ballpark with a lot of other PWRs like this, but also hotter than where you're operating today by 7 or 8 degrees. And my concern was as soon as I saw that well there's nothing stopping them from choosing a different set of operating parameters and still staying within the tech specs of running the plant at a higher temperature. All the way up, perhaps to 617. And then when you think about that you say, well what materials are in the coolant system. And I asked this question: Where are the locations of alloy 82, 182 or any instances of alloy 600 in the coolant system. And, obviously, your steam generators are changed. Nothing in the pressurizer from an operating parameter standpoint changes because you're operating at the same pressure. And so none of that is EPU related. But I keep thinking of the safe ends on the reactor vessel that weld to the cast austenitic stainless steel piping. Some plants had 82, 182 buttering in that area which in some plants, but not all plants, was subject to augmented inspection under Section 11 because of the susceptibility of that material to cracking.

And so I was trying to get some kind of assurance that in the long run your normal operating procedures, you're going to stay at or below 609 and the susceptibility to cracking is just a couple of degrees higher than that as opposed to getting the bright day someday that I'm going to run my plant a little hotter and be on the other side of it.

No one gave the description of where the 82/182 welds are, if they're used at all. Some plants didn't use them. And I need assurance that you're going to operate with the parameters that you set out in your slide.

MR. DUNNE: Let me try and respond. This is Jim Dunne.

One, I think there is an industry alloy 600 materials group out there forcing all the plants to --

MEMBER SIEBER: Yes.

MR. DUNNE: -- sort of identify where they have alloy 600 and how they're going to manage it going forward.

Right now we believe that the only places we have alloy 600 left in our RCS would be basically in the cold leg region of the reactor vessel there's some locations --

MEMBER SIEBER: Yes, the water under the vessel, those penetrations are often --

MR. DUNNE: Right. So we don't believe we have alloy 600 anywhere in the T_{Hot} side of the RCS at this point in time.

MEMBER SIEBER: What about the alloy 82, 182?

MR. DUNNE: I don't believe we have alloy 82 for the --

MEMBER SIEBER: 182?

MR. DUNNE: I would need to confirm that.

MEMBER SIEBER: Could you do that by the next time we meet?

MR. DUNNE: Yes, we can probably --

MEMBER SIEBER: I'm only interest in the hot leg.

MR. DUNNE: Right.

MEMBER SIEBER: Once you get to the steam generator, beyond that, it's okay with me.

MR. DUNNE: And we do have a person who is responsible for chasing all the alloy 600 around as part of this industry, alloy 600 committee, and we can talk to him and reconfirm that --

MEMBER SIEBER: Well, I'm only interested in what you're doing. You know, what the industry does is something else.

MR. DUNNE: Right.

MEMBER SIEBER: So just tell me about Ginna.

MR. DUNNE: Right. So I believe we don't have any of the hot leg either for the weld material for the alloy 600 material. But we can confirm that and get back to you on that.

MEMBER SIEBER: Be sure you check things like thermal welds.

MR. DUNNE: Right.

MEMBER SIEBER: Branch line connections, fence and drains.

MR. DUNNE: Yes.

MEMBER SIEBER: And all the way up to the hot leg of the steam generator, just that one section of pipe.

CHAIRMAN DENNING: Okay. Well, let me make a couple of comments about what I think we want to make sure that we see at this next meeting.

As certainly the small break LOCA. My guess is that we're not going to need much time on that from what I'm hearing.

The boron precipitation is the type of thing that we tend to get a little wild over. So I think you ought to figure that we're going to spend some time and ask questions that you're probably not going to be able to answer in that area.

Jack's comments.

I'd like to see a little more discussion on a couple of these limiting accidents with the regulatory type of analyses. And perhaps one of them might be the loss-of-external-electrical load and another might be the flow coastdown accident, although we've talked a little bit about both of those. I think as far as kind of walking us through those might be good examples.

If you also had more realistic analyses, too, that gave us a feeling as to what was there. I realize that you may not in those cases be able to do that.

So that's kind of the things that I think we ought to be sure that we cover at this time.

Otto, do you have anything that you'd like to say or comments you'd like to make? I haven't given you a chance.

MEMBER MAYNARD: I agree that the

presentations I think were very thorough and very good.

I think that it would be good to discuss a couple of these just to show the level of conservatism and why coming close to the limits is safe. I don't have a problem with it. The public and regulatory margins build into the acceptance criteria and into the acceptance of the approved methodologies, but I don't think in this meeting very good discussion that gave anybody a level of confidence that hitting that limit was okay. So I think we could have some better discussion in that and perhaps go through an example or so.

But overall, I thought very good presentations and good review.

CHAIRMAN DENNING: Graham, anything else?

MEMBER WALLIS: Well, as I said earlier, I think the safety analysis is really the key topic. We're here to talk about reactor safety and not a lot of details, and that was given a rather short shrift in this meeting.

What I would like to see is this table. Now where does this table come from that was handed out? Is this from applicant?

MR. MILANO: The licensing report, yes.

MEMBER WALLIS: Form the applicant?

MR. MILANO: Yes.

MEMBER WALLIS: It's not in the SER? Because when I read the SER, I don't get these numbers and I have no idea of the basis for your decisions. I think they should be there.

Now, what I would like to see is the comparison of the type that the licensee presented here of the most interesting situations along with the Chairman here where you're pushing the envelop. Because I tried this on another member of the Committee and he said it would be a red flag to him if he saw these numbers so close to the limit. He'd want to know why and what's being done about it and how the Staff satisfied themselves that that's okay.

So I'd like to see a table like that. It's just the basic information.

And I'd like to see where you are today before the uprate. I mean if you're at 3193 psig after the uprate, where were you before? What's the consequence of the uprate? We don't have any perspective of what's changed because of the uprate.

I have a very specific technical question here. You present the criteria and the result and say reactivity in addition to rod withdrawal in terms of psia. Now, what you measure is psig and the atmospheric pressure itself is uncertain within ten percent. If I take that uncertainty in atmospheric pressure, then I cannot convince myself that 2748.1 is less than 2748.5. Atmospheric pressure varies by, in the extreme case of hurricanes and so on, ten percent or so.

CHAIRMAN DENNING: Not in RETRAN it doesn't.

MEMBER WALLIS: But it does. And what you measure is -- so could you -- and when you're as close as that, you're within -- you don't really ever measure psia. And I don't know what RETRAN is. RETRAN assumes a certain standard atmosphere or something?

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: Okay. Well, that's a point. But I'm mystified by having a criteria in psia. When they're actually running the plant, you presumably measure psig or do you always correct for atmospheric pressure variations? I don't think you do.

CHAIRMAN DENNING: You don't have to answer that right now.

MEMBER WALLIS: Yes. But that is a peculiarity I noticed.

Anyway, the thing is the overview is important, especially for the full Committee. So before the uprate, here were the parameters in safety and here was the state of the plant in this n-dimensional regulatory box. And when they changed and they've had the uprate, they stretched this n-dimensional space they're in and they bump up against some limits. And make it clear what those limits are they're bumping up against. And then give some examples of how you satisfied yourselves that it was okay and what you did to satisfy yourself. But the number wasn't sort of ten percent one way or the other or something. That they've done an honest job of getting so very close to the limit.

And also, I think the accuracy of this is suspect, too. I mean, when you look at one part in 10,000 accuracy, especially on pressure, it's still dubious.

So that's really the main point I had. And when you get to the main Committee, and maybe you can come back to the Subcommittee meeting as a sort of a rehearsal for the full Committee meeting.

MR. MILANO: That was our expectations.

We were going to right now -- and again, this is preliminary and I'll discuss more of it with Mr. Caruso before we go there, but our plans were for the NRR staff to at least go through three different scenarios of our reviews, one being the normal approach that we'd take. When I say "normal," I mean the typical approach wherein we review methodologies, modeling, assumptions, assumption inputs and the outputs. One where we do that plus do independent audits. And then a third one where we do our independent calculations.

MEMBER WALLIS: Yes.

MR. MILANO: And you'll see the independent calculations more so when we talk about small break LOCA because we've been doing some extensive stuff in that and boron precipitation. So that was our plans during the next Subcommittee meeting was to go through three of those.

MEMBER WALLIS: Good. I didn't see this before I came here. This job with these numbers. Because the way things worked out I had a day to look at everything I was given. And I look at the SER. I mean I supposed to be the decision making thing. And I look at that. And if it doesn't give me these numbers, I have no idea what they are. I'm not going to go back and dig out something out of the application. I don't have the time to do that, and I assume that you've done it. But if you don't tell me in the SER -- I got very frustrated, I must say, reading that in the SER and trying to figure out what had happened to these various parameters.

Anyway, that's by the way.

CHAIRMAN DENNING: I think there is kind of a generic question here of what really should be in an SER and we're not kind of in that regulatory space as much as we are in some technical review, and maybe there really is a difference as to what really ought to be in the SER. But, you know, for us it really is frustrating not to see numbers. We're very number oriented.

MEMBER SIEBER: I think the Staff sometimes tends to use and approved methodology and set of codes rather than go through again the basis upon which that approval was granted in the past, they just reference the document of some SE someplace. And that's a shortcut, but that gives us more work sometimes in mystery land as to where some of these things come from.

I'm not sure what the solution to that really is, but I'm sure that it will evolve from our discussions.

CHAIRMAN DENNING: Any last questions by either side? No.

Thank you very much. And we're adjourned.

(Whereupon, at 9:52 a.m. the Subcommittee was adjourned.)