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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

MEETING OF THE SUBCOMMITTEE ON ADVANCED BOILING WATER REACTORS

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WEDNESDAY

DECEMBER 5, 2007

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The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 12:30 p.m., Dr. Said Abdel-Khalik, Chairman, presiding.

MEMBERS PRESENT:

SAID ABDEL-KHALIK
Chairman
OTTO L. MAYNARD
Member
WILLIAM J. SHACK
Member
JOHN D. SIEBER
Member
J. SAM ARMIJO
Member

MARIO V. BONACA

Member

MICHAEL CORRADINI

Member

ACNW&M MEMBERS PRESENT:

RUTH F. WEINER

MICHAEL T. RYAN

ALLEN G. CROFF

JAMES H. CLARKE

NRC STAFF PRESENT:

MAITRI BENERJEE

MARK TONACCI

MICHAEL GARTMAN

ZEYNA ABDULLAHI

DON DUBE

ALSO PRESENT:

ALAN BEARD

JOSEPH SAVAGE

DENNIS HENNEKE

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

12:31 p.m.

CHAIR ABDEL-KHALIK: The meeting will now come to order. This is a meeting of the Advisory Committee on Reactor Safeguards Advanced Boiling Water Reactor subcommittee. I'm Said Abdel-Khalik, Chairman of the Subcommittee.

ACRS members in attendance are Bill Shack, Michael Corradini, Otto Maynard, Jack Sieber, and Mario Bonaca. We may be joined later also by George Apostolakis and Sam Armijo.

Four members of ACNW&M are also in attendance, Ruth Weiner, Michael Ryan, Allen Croff, and James Clarke. Ms. Maitri Banerjee of the ACRS staff is the designated federal official for this meeting.

The subcommittee will gather information related to the design and licensing aspects of the ABWR application to prepare itself for the review of the COL application and action as appropriate for deliberation by the full committee.

The rules for participation in today's meeting were announced as part of the notice of this meeting previously published in the Federal Register. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

Most of this meeting is open to the public. If any proprietary information is required to be discussed as a result of questions from the members, I ask the presenters to notify me so that we can close that part of the meeting.

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. Participants should first identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

We will now proceed with the meeting and I call on Mr. March Tonacci of the Office of New Reactors to begin the presentations.

MR. TONNACI: Good afternoon, Dr. Abdel-

Khalik and other members of the committee and subcommittee. I am glad to be here. I am Mark Tonacci. I am the senior project manager for the ABWR. I am here with my supervisor Michael Gartman who is sitting on the side at the side table where I will be in a few minutes.

The committee has requested a brief on the key differences between ABWR and the earlier boiler designs. I think that was a good proactive request on your part because there has been a good bit that has occurred since we approved the DCD back in 1997. On the other hand, you have already had briefings on AP1000, ESBWR, and we are just going to try to hit the high points for you and not go through too much detail. I look forward to a dialogue with you today and value your input.

Today the briefing will have three parts. I'll be doing a brief introduction touching on the chronology of the ABWR and hopefully will help you get a bearing in your reference on the design documentation. Then I will hand off to GE Hatachi. That is the real focus of our presentation is on the technology. Alan Beard, who is sitting over on the side of the GE table, Principle Engineer, will focus on the differences in the design, the technical aspects of the design, and the operating experience.

After that Dennis Henneke, also sitting on the side with GE, Principle Engineer of PRA for GE Hitachi, will talk about the PRA aspects of the ABWR after that we will touch on licensing. Joe Savage of GE Hitachi will talk about the DCD Rev 4 and potentially Rev 5 and also talk about the departures and topical reports to some extent. He will then hand off to me and I'll wrap up with an NRC perspective on some of the licensing aspects.

I have also been asked to touch on the COLs and will describe what they are and a little bit about how we process those. We are tag-teaming the presentation today between myself and GE and we may defer questions to each other as appropriate.

With that, let me touch a little bit on ABWR chronology. As I just mentioned, the ABWR DCD was certified in about 1997 and it is in a state of finality which means really as an applicant comes in they use that design it is not open any longer to questions or changes.

There are 13 top cohorts that have been submitted by GE on their docket I guess through December of '06 through 9 of '07 of this year. They gave us those as a jump start on a potential future update of the DCD. These topical reports are also being used as referenced in the STP COLA, the South Texas Project COLA. These topical reports cover a number of things including the new RCIC pump as well as COL applicant information items. We will go into those in more detail later on.

The South Texas COLA was submitted to us in October of '07. At this point they are the only applicant. They do make reference to the topical reports as well, of course, to the DCD. We'll get into licensing aspects of this more later on.

The designs through the working group at this point is really not a factor because South Texas is the only applicant.

However, if we get another applicant for using ABWR technology, then South Texas 3 will be the reference COL and the applicants will be referring to that license or that application. DCD Rev 5 is a potential future activity that GE may come in with.

Excuse me just a moment. I'm battling the remnants of a cold. Okay. I wanted to give you pictorial representation of how these documents that I just mentioned sort of fit together for you. We have the DCD Rev 4 that was approved back in 1997. It is in a state of finality. We also have the topical reports, the 13 topical reports that have come in mostly in the course of this year. These will be coming to ACRS upon your request.

MEMBER CORRADINI: So these topical reports are on changes from what was in the DCD.

MR. TONNACI: That is correct. The new RCIC pump is an example. South Texas 3 and 4 application was submitted to us in October of this year. That will definitely come to ACRS as part of its approval cycle. The South Texas 3 and 4 application refers back to the ABWR DCD.

In many places in their application they simply have incorporate by reference where they will take a whole section of the DCD and say, "We adopt the whole thing." In other words, incorporate by reference. There will be pretty much nothing in their application on that except to say, "We adopt the DCD."

In other places they may choose to make changes. In that case they will point to a topical report, for example, and they will take a departure or an exemption depending on whether it's Tier 1 or Tier 2. They may also take other departures that are not part of the topical reports, either standard departures or site specific departures of their choosing. Those departures if they are Tier 1 the NRC has to approve those departures. If they are Tier 2 they go through a justification not unlike the 50.59 process.

Then in the future we have the ABWR DCD Rev 5. At least we hope we will. That will also be looking at some of the topical reports and incorporating those changes so they are kind of getting into some advance notice both with South Texas and ABWR DCD by sending the topical reports ahead of time so we can get an early start on those changes.

Are there any questions.

MEMBER SHACK: Would South Texas ever be able to reference the DCD 5? They will always be challengeable then in some sense or there is no finality on what they have done in the topical reports but once it becomes DCD 5, then there is finality. The topical reports have no finality whatsoever but once South Texas adopts those and we approve it, the South Texas design has finality.

In that light we won't go back and challenge it. But, for example, if the topical report comes through and it is approved ahead of -- say RCIC pump is approved of South Texas and then as part of the South Texas review wants to see some information about the RCIC pump, because that is part of the South

Texas application, it is open to questions and change be changed if it needs to be changed. That is how those work together.

MEMBER CORRADINI: And then what would be -- there would be no impetus for a DCD Rev 5 unless there are additional plant orders that use the ABWR or am I missing something?

MR. TONNACI: I think you're right but I really refer that one to GE.

MEMBER CORRADINI: And then you said -- you gave another pathway that I was trying to understand which is if somebody were to come in and say, "We want to do exactly what South Texas did," that would be another way to do it, essentially to reference their COL and, except for site issues, take that approach.

MEMBER MAYNARD: If you get into this later, that's fine. The topical reports, are they being reviewed? It looks to me like they were submitted and been reviewed as, I guess, a DCD with future regulatory changes pending of 50.62 or whatever. If that doesn't get approved, that could be reviewed as part of the COL. I'm a little bit confused on what criteria you are reviewing the topical reports under.

MR. TONNACI: Topical reports are reviewed to today's current criteria, whatever regulations we have at the point of our -- well, of today as we review these. They will get eventually approved by the division director. At that point they are just topical reports with the safety evaluation. They do not have finality and they can't actually be used by anybody. South Texas has to come in and says, "We want to depart from DCD and we want to adopt, let's say, the RCIC topical in its place.

It goes through the whole South Texas approval process and upon the South Texas approval, then the RCIC topical report is final for them and only for them. The next person coming in they will have to justify that as a departure or they can do it using a South Texas standard departure which would also work and has a measure of finality there. There is some risk on both parts but the good part of the topicals it gives us several months, almost a year, to get started on these things ahead of time. That's where we are.

MEMBER ARMIJO: So the ABWR certification is not being amended by this process?

MR. TONNACI: That is correct.

MEMBER MAYNARD: The law doesn't allow it to be admitted.

MR. TONNACI: Generally speaking you are correct unless we get into the back-fit rule. That is all I wanted to go through and at this point I'm going to turn it over to Alan Beard to really focus on the technical aspects of the design.

MR. BEARD: Good afternoon, everybody. As Mark said, there has been a lot of turnover in the ACRS since we were doing this back in the mid and late 1990. In fact, I think the only member who was ACRS at that point is not here. Dr. Shack came in about halfway through but Dr. Kress is the only other member that was part of the process.

MEMBER SHACK: He's gone.

MR. BEARD: Dr. Kress is gone?

MEMBER SIEBER: Yes.

MR. BEARD: I must have missed that piece of information. Okay. I remember being on ACRS where we had a similar snow day like this and the only people who made it to the meeting were the ACRS members and GE. Glad to be back here.

Like Mark said, we are just going to try to give you a fairly high-level overview of the ABWR just to kind of start to bring you up to speed and to start your thought process about any questions you might want to ask.

The outline of what I'm going to present is up there. I'll talk a little bit about the design evolution of the ABWR. Focus on a lot of improvements we've made in the design. Talk a little bit about how the containment is different from the containments we had in our earlier product line. Talk about the nuclear steam supply. Spend a fair amount of time talking about our engineer safety features and emergency performance systems.

Then Dennis Henneke over on my left there will talk about the PRA PSA insights we've had and what the calculated core damage frequency is and how we factor some of those insights into the design.

Next slide, please, Dennis.

MEMBER ARMIJO: As you are going through this, could you give us a little bit of input on these various topical reports, how they impact what you're talking about? This is a design that is going to change for the South Texas project and it would help us kind of understand where you're going.

MR. BEARD: To the extent that I can think of that and where it lends itself to it, I certainly will do that.

MEMBER ARMIJO: Like the recombiner issue.

MR. BEARD: Recombiner issue, medium voltage, RCIC pump and things like that. I have to admit, I just took my ESBWR hat off and put my other hat on. I've got to switch my brain processes over.

BWR, nothing real earthshaking here. We have over 40 years of operational experience within GE. Actually, that's almost 50 now with the commercial operation. Operating pressure, we are operating 1040 psia just to make a point. Just like we're doing with the ESBWR, the ABWR was designed with si units.

That's largely because the ABWR was developed as a collaborative effort between GE and Tokyo Electric Power Company so we have just carried that forward and we do design si units for the ABWR. That 1040 psi corresponds to the saturation temperature of about 550 degrees F.

MEMBER SHACK: Could you just explain to me what the relationship between Toshiba, GE Hitachi is on this plant?

MR. BEARD: I'm going to defer to Joe Savage for that if I could, please.

MR. SAVAGE: I'm Joe Savage of GE Hitachi and I'm the licensing manager. Right now it's a commercial relationship. We are looking for a commercial success path forward. GE and Hitachi have combined our nuclear capability into one company, hence GE Hitachi on our name tags. Toshiba has been hired by the owners of South Texas project which is NRG to be their EPC contractor.

MEMBER CORRADINI: Engineering procurement constructor.

MR. SAVAGE: I'm sorry, engineering procurement and construction. Right now we are working on division responsibilities, whose turbine will be supplied, who will build the reactor vessels, who will build the control rod drives, who will provide the control room.

MEMBER SHACK: But this is a GE Hitachi design?

MR. SAVAGE: Yes.

MEMBER CORRADINI: And as a takeoff from the four units operating now in Japan, as I understand it.

MR. SAVAGE: Exactly. Yes, sir. Plus the two that are being constructed in Lungmen in Taiwan.

MEMBER SIEBER: You have 13 topical reports that we have that you folks have provided to us. Is that all or will there be more? If so, how many more?

MR. SAVAGE: Those will probably be all. Let me mention that the ones that Alan is not going to be that familiar with are the ones that answered COL action items basically providing additional information to the DCD. I think Alan has already mentioned the major design changes those topicals will bring in to the GE Hitachi design.

MEMBER SIEBER: So all the information we will need will be either on that disk or from the staff?

MR. SAVAGE: Plus the COL application from STP 3 and 4.

MEMBER MAYNARD: But these are only covering areas of change. The DCD that is already approved isn't changing. We wouldn't have anything on that.

MEMBER CORRADINI: Unless you have it from '92.

MR. BEARD: Correct.

MEMBER CORRADINI: You said it and I guess since you brought it up I'm going to ask. In designing the si units what is the implication of that that I might be missing other than everything just changes in how you -- what changes technically in terms of the turbine or the generator or the machine.

Nothing?

MR. BEARD: It's really almost transparent to the operator.

MEMBER CORRADINI: Okay, fine.

MR. BEARD: All our calculations that are done in si we are not doing them in English and converting them.

CHAIR ABDEL-KHALIK: Are the instruments in the control room going to display parameters in si units or British units?

MR. BEARD: Again, I'm going to have to refer to Joe.

MR. SAVAGE: My understanding is that South Texas project wants the capability of both. The Lungmen plant control rooms can display in either native Taiwan language or in English and that is a detailed design decision that South Texas project will make as we go forward. They will have that capability to have it both in si or in English and will build in appropriate software to do that.

MR. BEARD: Okay. Like all BWRs for this direct cycle we are allowing saturated steam to exist from the reactor pressure vessel directly to the main turbine. Again, just like the ESBWR, and this is a surprise to many people, the exit quality of our team as it comes out of the RPV is in excess of 99.9 percent which is actually higher than most PWRs currently on the market. We do characterize it as an evolutionary design, a Generation 3 plant. It's not Gen 3+ or certainly not Gen 4.

Again, basic BWR operational experience. Power is controlled through a combination of positions, control rods as well as varying core flow. Flow control in ABWR does provide us with the capability to rapidly change power, although it very rarely used but that capability does exist.

Again, no Boric Acid is used as a moderator. We are boiling the condensate or the demineralized water so we do not have a need for boric acid in a moderator. The ABWR in Lungmen is designed for 100 load rejection. The certified design only has a 32 percent bypass capability so it's not capable of taking a load rejection from 100 percent power without scramming the plant.

If the license application or license applicant chooses to go 100 percent bypass that's a very easy design module to accommodate but then they would have to get NRC concurrence that they would be allowed to operate that plant in an "Island Mode" of operation which would be a licensing issue to be addressed at a later stage.

MEMBER CORRADINI: Just to make sure I understand, for South Texas that would be something that is to be chosen?

MR. SAVAGE: To be chosen. Yes, sir.

MEMBER SHACK: And no decision has been made yet?

MR. SAVAGE: Correct.

MR. BEARD: And just as a reference the ESBWR as a base certified design we are incorporated 100 percent load rejection capability.

Okay, BWR evolution. You have seen a variate of this slide when I've been up here with my ESBWR hat on except we got rid of the ESBWR further off on the end of the snake. Dressed in one it looks like a PWR but, in fact, run a saturated steam. There's an external steam drum up here and some steam generators.

Steam drum was maintaining a saturated pressure in there. Then we were circulating just slightly subcooled water up through the steam generators. We went to, again, still external steam generators but we had the steam bubble inside the vessel providing for the saturation control here.

Then Oyster Creek and Nine Mile 1 were the first of the really large direct cycle class that we went to. They were characterized by five external recirculation loops. One of the problems with that was they take up a lot of room in the drywall as well as they present a significant challenge when you postulate that you get a double-ended guillotine break, especially that lower portion in line. When we were doing the LOCA analysis you had to rely very significantly on spray and steam cooling to show that we were not having catagraphic fuel damage.

So then the BWR-3 and then on through the 6's we adopted the jet pump concept where we had just two large external recirc loops but then we had the jet pumps located inside the annulus area created by the shroud. That gave us the ability even if we had a double-ended guillotine break of the lower suction line to flood up to at least two-thirds of the core height and then we relied upon the spraying steam cooling to ensure again that we had adequate core cooling.

ABWR. The big differences you see there is no external recirculation loops. We went to what we called reactor internal pumps, also known as RIPs. There are 10 of those mounted on the bottom periphery of the vessel. We actually only need nine of those 10 to operate and support 100 percent power operation but they did. By adopting the RIPs we were able to eliminate the large break below the top of active fuel as one of our significant design basis considerations.

Next slide, please. Nice color slide of what the ABWR looks like. The main features I want to point out here are the 10 reactor internal pumps. They are situated again around the periphery of the lower head of the RPV. You see pretty conventional BWR here, the control rod guide tubes with control rods in them.

The core plate which the guide tubes slip through and then the support castings are also inserted in there. The fuel assembly is sitting on top of those support castings and then the top guide. They are surrounded by a stainless steel shroud and there is a 12 to 14-inch gap between the shroud and the RPV.

MEMBER SHACK: And your internals are welded internals in the ABWR. Right?

MR. BEARD: They are welded internals, yes. Well, the shroud is welded. The core plate and the top guide are bolted in and then tack welds to make sure that nothing shakes free. Certainly the top guide and core plate can take it out. We have actually done the engineering and developed the tooling to allow us to go in and cut out a shroud and place it as well.

MEMBER SIEBER: How tall is the vessel from the bottom half to the top half?

MR. BEARD: It's just shy of 21 meters if I remember correctly.

MEMBER MAYNARD: To work on the internal pumps there do you have to take those out from inside?

MR. BEARD: There's actually two things you're doing. If you are going to pull the impeller you pull that from the inside up through. If you could work on the stater and field you actually back-seat the impeller. There is an inflatable seal in there and then we can go in and drop the cover plate off the bottom part of the housing and go in and work on the stater and the field.

CHAIR ABDEL-KHALIK: The impeller is pulled from the downcomer and discharged towards to the bottom of the vessel?

MR. BEARD: The impeller from grappled from above and lifted up.

CHAIR ABDEL-KHALIK: I mean, in terms of how this pump -- where is the intake?

MR. BEARD: Oh, I'm sorry. We are pulling water from the downcomer and discharging it into the bottom.

MEMBER SHACK: And the steam dryer design here is the same as in the operating plants in Japan?

MR. BEARD: The same as in the ABWR operating plants in Japan which is an improved version of the ones we have for our BWR-3 through 6's as well as the steam separators are also the new and improved steam separators with the lower pressure drop through them.

Any other questions on the basic configuration?

MEMBER CORRADINI: If you're going to get to it. I'm sorry I can't remember so I'm like you. I remember ESBWR, ABWR current. In the ABWR what is the fuel height?

MR. BEARD: Fuel height is 3.6576 meters, 12 feet.

MEMBER CORRADINI: So higher than ESBWR.

MR. BEARD: It's two feet wider than the ESBWR. Steam separator/steam dryer. Pretty conventional. We do have -- we talked about it on the ESBWR but the flow orifice or restriction element is built into the main steamline nozzles. We use that to limit the pressure drop across the internals should we have a double-ended guillotine break in the main steam line. We also use it as the instrumentation top for measuring steam flow coming out of the RPV.

Next slide, please. We are continuing to use pressure suppression containment. The reason I wanted to talk about this is when you look at the following slides the way that we do pressure suppression containment is a little bit different in this design. It will look much more like what you have seen with the ESBWR but the ABWR really represented out first movement away from some of our other Mark I, Mark II, Mark III designs.

It consist of two major elements, drywell which is further divided into an upper and lower section as well as a wet well which contains the suppression core and what we call the suppression pool and airspace. It is lined with steel to minimize the leakage through the reinforced concrete. The reinforced concrete is two liters thick. Large reinforced with No. 18 rods. Three layers on both the inner and outer faces so it is heavily reinforced and the steel leakage liner on that.

We do inert with nitrogen during operation. The result of that is when the new flammability control rule was promulgated three years ago now, I guess, We allowed the option if you had an inert containment that you could eliminate the recombiners have active recombiners.

We have active recombiners in the design previously to comply with the flammability control rule. With the new updated rule we have gone back and taken up that and freed up some space in the reactor building and eliminated some penetrations in the primary containment to contain those.

MEMBER CORRADINI: So the drywell as it travels is inerted?

MR. BEARD: Yes.

MEMBER CORRADINI: And with the Mark -- now I'm going back in time. With the Mark III that we currently there are not inerted but they have the recombiners.

MR. BEARD: They didn't have recombiners. They had igniters.

MEMBER CORRADINI: Igniters. I'm sorry. Excuse me.

MR. BEARD: Because we have such a large volume that we could not process enough air through a recombiner to take care of that. Okay. Just like with all the suppression containment steam released during an accident or transient is routed to suppression pool where that steam is condensed and allowed to bubble up into the suppression pool. It doesn't bubble up because it is condensed. But enter the non-condensable gases that might have been moving with that steam as it passed through the suppression pool do bubble up and accumulate in the suppression pool airspace.

Next slide, please. So very early on GE did use large dry containments but very quickly we became enamored with the concept of precious suppression containments. In the three operating versions, at least domestically, are depicted here in the center of the Mark I, Mark II and Mark III, Mark I Nine Mile 1, Oyster Creek, some of the early BWR-4s, Browns Ferry. Some of Exelon now use Mark I.

Mark II was introduced with the BWR-4 line so there are some BWR-4s out there that are in Mark I containments. There are some BWR-4s out there on Mark II containments. Most of the BWR-5s I believe are in Mark II containments. Then the BWR-6 -- all the BWR-6s were put into Mark III containment. The red line on here is the boundary of the primary containment so you can see it's fairly large.

We got it fairly compact but it was pretty difficult to build this. We made some simplification here. Still had a fairly compact primary containment. We were introducing steam gap through vertical pipes into the suppression pool to give us our steam condensing.

Then we went to the Mark III where we had a dry route and then there was what we call the rear wall assembly so when we had steam accumulate in the drywell it pushed down through and then expanded out through a rear wall out into the suppression pool again without the steam and then the noncondensable gases that might have been accumulated there filled this rather large wetwell airspace.

This is a free-standing steel shelf. It turned out to be fairly expensive to build. Then there are some other operational issues with that. When we went to the ABWR we wanted to look at lessons learned so we adopted the best of all the features of all these three containments and this is what we came up with, a fairly compact design. You see the upper drywell in this location here, the lower drywell underneath the RPV, and then the suppression pool and the wetwell airspace out here and the annular ring around the lower drywell.

In the event we had a live break in the upper drywell, the steam now went down through what we called 10 vertical vents. They were about 1 meter in diameter.

They were built into the pedestal wall and then those 10 one meter diameter vents go down and they are separated into three horizontal vents each which is about seven meters in diameter at three different elevations and that allows the steam to exhaust horizontally into the suppression containment again where it is condensed. Very much like what we are using on the ESBWR except the suppression pool is not elevated up off the base mat like we have for this. Any questions on that?

Okay. So if you took --

MEMBER CORRADINI: Can you point to where the vacuum break -- oh, you have it there. I'm sorry.

MR. BEARD: The vacuum breakers are right there. The vacuum breakers in the ABWR are horizontal configuration and they penetrate between the wetwell airspace and into the lower drywell area and they are just a very simple flap or valve type of arrangement.

MEMBER CORRADINI: Is this the design from current operating plants or a new design?

MR. BEARD: It's basically what we have in the current operating plants but it has been approved. It has enhanced instrumentation to verify that we do have the valve in the seated position.

MEMBER CORRADINI: Then I'm still transitioning from my own mind, I apologize, to the ESBWR. Is this the design in the ESBWR?

MR. BEARD: The ESBWR is using three vertical valves which are located up on the diaphragm floor.

MEMBER CORRADINI: Okay.

MR. BEARD: They are kind of a lift-pocket type of assembly for lack of a better characterization. When you have that the pressure difference across that pocket will lift to lift to allow the pressure to equalize between the two airspaces versus the hinge valve assembly.

Again, you can see the vertical vent here. There are 10 of those in the ABWR design, one meter in diameter as it comes down through what we call the pedestal wall which is this cross-hatched area comes down and then you see the three horizontal vents coming out into the suppression pool.

They are fairly uniformly spaced but there are two places. I think they are at every 36. Not every 36, every 30 degrees. That leaves two segments where we don't have those. The reason for that is not shown on this Fig. R2. Tunnels that come through the suppression pool and suppression pool airspace to allow us to access the lower drywell area. Where those goes through the pedestal wall we do not have a vertical vent going down to that particular area.

You do see just the steam collector pipe going to our X collectors. Those X collectors are what we use in the operating ABWRs in Japan and started running them and the ones we are also using on the ESBWR. Then because it is an active plant versus the passive plant we do have a standby gas treatment system.

The area that we are defining from secondary containment is within the dotted lines here. You will see that it's not in all cases the absolute external part of the reactor building. We do have areas of the reactor building that we are maintaining as non-contaminated areas that house primarily electrical equipment that we want to make sure that we keep clean so we can minimize the radwaste generation and operational exposure. Any questions on that particular slide before I move on?

Just a colored artist rendering cut-away. Grade elevation is here. There are three elevations of the ABWR below grade and then three elevations above as well as the operating deck above that. There are three emergency diesel generators. I'm getting a little bit ahead of myself but the basic approach of the ABWR is we had three divisions of equipment. Although it's designed under the premise of a single failure plant, the reality is for almost all of the transients and accidents it has an N-2 capability.

Those three divisions are housed in different quadrants within the reactor building and so Division 1 would be over in this quadrant vertically. This is the Division 3 quadrant or Division 3 equipment is in this quadrant. Then the Division 2 equipment is in this far quadrant over here. This is plant north going this way.

We have Division 1 in the northeast quadrant, Division 3 in the southeast quadrant, and Division 2 in the southwest quadrant. Division 4 houses no mechanical equipment for safety purposes. It doesn't have emergency core cooling pumps. It doesn't have any engineered safety feature equipment.

It does have the fourth division of instrumentation housed in there as well as the reactor water cleanup system and other things are housed over in that area as well. The basic premise is the three safety-related divisions of equipment are in these three quadrants and then the fourth quadrant is set aside for the safety-related instrumentation as well as a lot of the balance in play of equipment that is needed for the nuclear island.

Okay. Great elevation here so --

MEMBER SHACK: How long could this operate in a station blackout?

MR. BEARD: That's an interesting question because by the certified rule this plant is characterized as an alternate AC power plant. What I mean by that is we have the combustion turbine generator. The combustion turbine generator is what the staff, and this is part of the -- Jerry Wilson, if I get this wrong. Jerry left.

Back in 93-087 and 90-016 phases when the SECYs came out it was mandated by the commission that four advanced plants that you were going to be alternate AC, you were no longer going to play with coping capability. From that rule perspective we are characterized as alternate AC power plant.

The reality staff is the staff and GE really like the capabilities that RCIC give us which our reactor core, isolation core that is steam driven. Although we are classified as alternate AC power plant, RCIC by itself gives us about eight hours worth of station blackout capability.

MEMBER SHACK: That's not seismically qualified though?

MR. BEARD: That's correct. Combustion turbine generator is not seismically qualified. Okay. So three elevations below grade. The diesel generators, again this is a fairly significant change from the existing plants, are actually housed inside the reactor building. We wanted to minimize the number of safety-related structures that we built for this so you have three diesels again in the same quadrants as the rest of the safety-related equipment.

The control building is located mostly below grade and is sandwiched between the turbine building and the reactor building, the control room and two other elevations that are below grade. Then there is a little bit of a control building that does stick up above grade but, again, it is sandwiched between the two buildings.

This is the turbine building depicted here and you can see the high pressure followed by three low-pressure turbines and the generator on the far end. Then there is an electrical building annex built onto the side to handle most of the medium voltage switchgear and also house the combustion turbine generator that is part of the base design.

That was all I really wanted to touch on on that particular slide so I'll pause and see if you have any questions before I move on.

CHAIR ABDEL-KHALIK: What is the capacity of the spent fuel pool?

MR. BEARD: I'm going to have to defer because I don't know. It's at least 10 years with the provision for another core off-load but I think we can squeeze a little bit more in there but the certified design says a minimum of 10 years plus a core off-load.

Back up one slide. I'm sorry. The spent-fuel pool is this part of the pool up here on this elevation. It's not the entire volume of water up here because you can see that is a step that actually occurs in there so the spent fuel is actually located in that step off beyond where the containment wall comes into the design. Not all that water up there houses spent fuel. It's just this outer portion, the southern most portion of the spent fuel pool.

CHAIR ABDEL-KHALIK: What is the rest of it for?

MR. BEARD: The rest of it for we can store things like guide tubes, fuel support castings, control blades in chorus rotation that has come out we can cut up and store in that area. The way the design worked we had to provide a means to get out beyond the top of the drywell to get the depth down to where we need to so we just restore some of that other equipment and the fuel go down that other portion.

MEMBER MAYNARD: Three divisions. Can one division handle everything that you need?

MR. BEARD: If you will hold that, I will get to that when I get to the slides on ACCS.

Next slide, please. The advanced boiling water reactor, the ABWR -- the A does actually stand for something in this unlike the ESBWR where the E doesn't stand for anything -- has been licensed and/or certified in three countries those countries being Japan, Taiwan, and the United States. It is the first of the Generation 3 class that was certified under NRC Part 52, quite an experience for those of us who were part of that. There are four currently operating in Japan.

Up until about two months ago I could have told you that those plants had experienced one unplanned scram which is the result of a lighting strike out in the switchyard. I'm sure you are aware of the earthquake that happened at the Kashiwizaki-Kariwa site. They do have seismic scrams built into these plants so that seismic event resulted in a scram of K7 was the one that was operating.

K6 was the refueling so one of the ABWRs that at that site experienced another unplanned scram due to a seismic event. Like I said, that is part of the reactor detection system circuitry over there. They do have seismic scrams as part of their base design.

There are four operating in Japan, the two in Kashiwizaki and Kariwa, Shimane 3 and Hamoka 5. They are continuing to build, at least Tokyo Electric Power Company. ABWR is their design for the foreseeable future. We also are currently involved in a project in Taiwan, the Lungmen project which is two ABWRs that are being built where GE has the lead on those. They are moving along, unfortunately as fast as we would like to. That has nothing to do with the design or availability of equipment. It's been primarily a political issue over there.

Power levels. The certified design is 3,926 megawatts-thermal. People scratch their head and say, "Where did you come up with a number like that?" The reality is in Japan they license on electrical power output, not thermal power output. I don't understand all the dynamics of why they do it but the bottom line is when you back it out in Japan it came out to 3,926 megawatts thermal.

We did bid very aggressively in Finland for the opportunity to provide ABWR for the Finland 5 Project. When we offered that we did offer an upgraded version, 4,300 megawatt-thermal. That was accomplished very much like we've been doing our power upgrades. The capability was already in the core.

We gave some enhancements in the balance of the plant, steamline sizing, turbine sizing, things like that. Then we did a little bit of adjustment on some of our heat exchangers but bottom line is it does have capability to upgrade up to about 4,390 megawatt-thermal output. That will result in about 110 extra megawatts-electric being generated by the plant.

Next slide, please.

MEMBER MAYNARD: Does the U.S. design have a seismic trip in it?

MR. BEARD: My recollection is we did not, no. That's not part of the RPS.

MEMBER MAYNARD: Personally I think that's good.

MEMBER SIEBER: Not immediately.

MEMBER MAYNARD: Sometimes you don't want to trip until you find out what you have.

MR. BEARD: I can't say with 100 percent certainty but my recollection is we did not have it. There is seismic instrumentation but it's not part of the RPS circuit.

MEMBER ARMIJO: Are the South Texas plants going to be 1350, the certified design, or the 1460?

MR. SAVAGE: Actually, the 13th. That slide says 1365 depending on cooling water conditions.

MR. BEARD: Okay. So, like we said, 3926 megawatt-thermal. That translates to about 1365 megawatt-electric gross. That is a nominal summer rating for that particular plant. We are using the reactor internal circ pumps which resulted in the elimination of recirc piping and they are canned rotor pumps.

They are wet fields that are in there that we have no rotating seal that it's in there. Very good maintenance or very low maintenance required so they have been very successful. Like I said, there are 10. Nine of those operating is enough to ensure adequate core flow to support 100 percent power operation. However, if you had one trip.

If you are running with 10 and you have one trip, you can do 100 percent power operation but before we can restart that 10th we'll actually have to drop power down to about 20 percent to get some back-resistance out of the pump before we can restart it. Also to give us room to make sure that we don't go through 100 percent power when we introduce that. That is a very quick evolution and then we are back to 100 percent power operation.

We did automate the design of the plant. It has three safety systems, three divisions of safety systems and the automation is such that there is no operator action required the first 72 hours. Again, as I have said before for the ESBWR, that doesn't preclude operator action but for the first 72 hours there is nothing the operator needs to do to make sure that the plant stays in a safe state.

The design parameters. We did follow --

MEMBER SHACK: When are you going to explain what isn't covered by three safety divisions?

MR. BEARD: Ten more slides. We did follow the EPRI URD recommendations for the site parameters, extreme wind, temperature, seismic and tornado missiles. It varies from about 60 hertz to 50 hertz. We did do a quick .3g earthquake using the Reg Guide 160 spectrum. That is not the expanded spectrum that we are using for the ESBWR. Back when we were certifying this high-frequency issue had not raised its head yet but it is analyzed and designed for all soil conditions. Now, the product or the offering in Taiwan has actually been upgraded to .4g earthquake.

MEMBER ARMIJO: What were the first two ABWRs? What was their seismic?

MR. BEARD: .3g roughly. There is not a direct -- I've gotten the tutorial on this over the past week. There is not an exact one-to-one correspondence between the way the Japanese do it and the way we do it but the seismic input was roughly a .3g earthquake as their design basis. I know most of you are aware that they exceed that by a substantial margin, the earthquake that occurred.

Next slide please. Tornado 300 miles an hour. A lot of these I just want to put up for information. The temperatures with deviations -- I shouldn't say deviations -- the departures for South Texas for 0 percent exceedance. The design of the reactor service water system will use a higher wet boil temperature. 85 degrees? Is that correct? Because of the very humid conditions that were down there. The rest of that stays the same.

Next slide, please. Soil bearing capacity. Again, these are all standard and I won't spend a whole lot of time on them. Maximum site flood level, I don't plan on going there today. Suffice it to say that the maximum site flood level at South Texas project is a site specific issue and Joe will cover that in a lot more detail on his set of slides.

Minimum groundwater level. Just like for all the other plants that have followed URD we don't have to de-water the site. We are saying that we can add that amount of bouncy with groundwater up to at least two feet below the finished grade of the plant.

Next slide. So the site specific design elements and then I will get into the heart and soul of this. The circ water system, the ultimate heat sink, which is reactor service water and that is safety-related, off-site electrical and then make-up water, other site works.

Next slide, please. ABWR site plan. Containment inside the reactor building. Again, Division 1, 3, and 2 will be in these quadrants here. The steam tunnel housing the four main steam lines as well as feedwater lines comes out through a substantial reinforced concrete tunnel, or chase I guess is a better word because it's not underground, which actually goes over top of the control building before it marries up with the turbine building down here, the administration building over here, the radwaste building over here, and then the turbine building and the electric annex on the side of that.

Then we have for the ABWR the diesel generator. Diesel tanks are buried underground and the piping from those tanks comes through tunnels or chases and then feeds to the diesel generator and these three quadrants. Then you see some other tunnels here. It is part of the ABWR certification but all process piping will be housed in tunnels and not directly buried in the soil. Questions?

MEMBER SHACK: The spent fuel pool then would be directly at the bottom end?

MR. BEARD: The spent fuel pool is in that part of the reactor building in that general area, yes.

Next slide. So you can get a little better idea that this is the area where we store the spent fuel pool and this would be the south side. Great elevation. Although in this cut-away the diesel generators are lateral within this picture, they would be at this particular elevation. The core, just to give you an idea, would sit just about in here.

The core is mostly below grade. I think there is maybe one foot that sticks above grade but then the three elevations of reactor building below grade providing this substantial capability for external events that might be postulating and then, I think, another 120 feet from here up to the top of the roof of the reactor building.

Next slide.

CHAIR ABDEL-KHALIK: Where do the tunnels for the diesel fuel lines come into this? What elevation?

MR. BEARD: They are just below the surface. They would be somewhere in this area. They come in just below and then they turn up to go to the fuel oil tanks, the day tanks, but they would penetrate just below or come in just below grade and then come up.

Next slide. Just an overall flowchart. I won't spend a whole lot of time talking about the balance of the plant. It's fairly conventional. Most of what we have talked about for the ESBWR is applicable over there. The design described in the DCD is being changed. They are going to go more with the ESBWR approach where we have four trains of pumps as well as an extra filter or demineralizer to ensure that they maintain 100 percent power operation on any piece of equipment out of service on the balance of the plant.

We are using motor-driven feed pumps. That is another departure from the certified design. The certified design had two steam-driven feed pumps and one smaller auxiliary motor-driven feed pump. We are now going with four 33 percent capable motor-driven feed pumps for the balance of the plant.

Overall on the nuclear island you see two of the three safety train divisions depicted by the pumps and heat exchangers here and then the third safety division is depicted here. I won't spend a lot of time talking about it on this chart because we will get into it in later charts.

A reactor water clean-up system which takes water from the RPV, processes it, cools it a little bit, and then returns it back to the RPV using the connection to the one of the feedwater lines. We have a suppression pool clean-up capability.

The pump takes suction out of the suppression pool, filters it through the filters that are part of the fuel pool cooling clean-up system. Then that water is returned back to the suppression pool. We have the spent fuel pool cooling and clean-up system, water taken out of the spent fuel pool, filtered, cooled, and then returned to the spent fuel pool.

Standby liquid control system, single tank of enriched sodium pentaborate with two positive placement pumps. Those pumps are sized on accordance with the ATWS rule that was promulgated by the NRC. I believe they deliver somewhere on the order of 80 gallons per minute per pump.

CHAIR ABDEL-KHALIK: Are these clean-up systems continuously operating or are they intermittently operating?

MR. BEARD: The fuel pool clean-up system is pretty much continuously operating. The suppression pool clean-up system would only be operated as needed. Now, just like we've done with the ESBWR which is something we took from the ABWR, all the normally wetted surfaces within the suppression pool are stainless steel clad. We are not putting epoxy on carbon steel to try to prevent corrosion.

We are going to go ahead and spend the extra money and put stainless steel in for the cladding on those surfaces. There is a lot less debris hopefully being generated in that suppression group that the suppression for clean-up system needs to take care of.

MEMBER SIEBER: Could you describe the

sump filtration?

MR. BEARD: For the ABWR there are not sumps per se. There are equipment sumps and equipment drain sumps that are located down here in this part of the containment but there is no sump that collects the water.

MEMBER SIEBER: Debris.

MR. BEARD: Debris. It either comes down through the connecting vents whether it be carried over by water flushing it down there or by the high-pressure steam flow. Then we do have the strainer issues that address the rest of it there. There are specific requirements and I think they have been amended as part of the COLA to update the most recent NRC guidance on what the size of the particular strainers needs to be.

MEMBER SIEBER: But your largest break is how big?

MR. BEARD: It would still be a main steamline so 28 inches.

MEMBER SIEBER: Right.

MR. BEARD: Within the DCD there are specific criteria about figuring out where the break location is, how much debris is generated, what is the damage area. Conservatively we committed to say all that debris gets sweeped directly into the pool and is available for transport to the suction strainers in there.

MEMBER SIEBER: Do you think that you will be able to meet whatever comes out of the next round of questions on BWR sump strainer?

MR. BEARD: I'm not familiar enough with that issue to make a comment.

CRD hydraulics. I don't want to spend a lot of time because I know you guys want to get into the emergency core cooling system so next slide. Okay. BWR-4 typical, BWR-5 and 6 and then ABWR. BWR-4, in effect we have two trains each of which is about 100 percent capability. As we are going across here I want you to be looking down here at all this. A low-pressure capacity 42,000 gallons per minute of water that we could move.

That was because we had 12 fairly significant break location for below the top of active fuel. Even though the 42,000 gallons per minute are peak clad temperatures well below what is allowed, or permitted, I should say, at 1,600 versus 2,100 but still some heat-up of fuel going on. We did have operator action required to ensure that occurred. Two trains, limited high pressure capability. We had low-pressure core sprays and low-pressure cooling ejection.

Core sprays were actually crediting distribution of water over top of the fuel and then that water dropping down through the fuel channels. LPCI was actually injecting through the core shroud but right outside and then allowed to start to fill-up the two-third core height that we had so that one was water coming back up through the bottom of the fuel assemblies and then cooling with submergence as well as steam cooling from the top of it.

Then the HPCI pump is steam driven pump provide us capability at high pressure. Pretty much just two divisions and then we have an automatic depressurization system to allow the low pressure systems to come in. Only a single capability with the high pressure. We only had typically two diesel generators or two trains of diesel generators to support this.

With the BWR-6 we went to our three-train approach. Our low-pressure trains were train 1 and train 2. Then we had a high-pressure core spray which was what I'll call train 3. I don't remember the exact designators. We had a dedicated diesel generator for Division 1, diesel generator for

Division 2.

Then there was a dedicated diesel that served only the high-pressure core spray system so we went from HPCI, which is kind of a high-pressure core objection steam-driven pump to a high-pressure core spray which is a motor driven electric pump which had its own dedicated diesel.

Again, single capability for high pressure, two divisions of low pressure capability. We still have the large line break but some of the enhancements we made up there a lot less water needs to be moved and we get lower peak clad temperatures as a result is transient accident.

When we went to the ABWR we actually went to three separate trains. Typically some of the charts we have this ADS would actually be in the crust up here. We have both and high-pressure and low-pressure capability within each of the three trains.

The question was raised earlier what is the capability of each of those divisions? Our analysis was a single failure so we always try to get two divisions of equipment being there. When we sharpen the pencil later we have actually determined that any one of these divisions operating ensures adequate core cooling.

A little tricky thing that went on here. There are five motor-driven pumps in here and I haven't really described this. Reactor core, isolation core, and there is a steam driven high-pressure cooling pump. We are incorporating a new steam-driven RCIC pump as part of the South Texas application. What is different about that? The old RCIC here that was part of the certified design was based on turbine technology so we had a separate steam turbine and a separate pump.

The Weir pump, which is out of a company from Scotland which has been providing these nuclear-grade pumps to the British Navy for a number of years, is a single consolidated unit, much more fault-tolerant. The RCIC pump has two flow speeds, 800 gallons a minute and 400 gallons per minute. It was not a variable flow type of pump. The new Weir pump actually gives the operator the capability to vary the speed of the pump, to vary the amount of coolant that he is injecting in the vessel.

Why is that significant? With the old RCIC early on when you had a lot of decay heat there you are making up, making up and so it may be quite a while because I'm basically steaming off that full 800 gallons a minute that I'm putting in there but as I start to come down to the decay heat now I start to refill the vessel and automatically because, remember, we automated everything in this design, at some point it would refill the vessel up to what we call Level 8 where the pump would be tripped.

Then we have no cooling made up for a station blackout condition so the water level starts going down because I've got safety relief valves allowing that steam to go out and it would drop back down to Level 2 which is an automatic initiation standpoint. Well, from an operational standpoint on/off, on/off eventually is going to cause you problems. When you want it to go back on it's not going to come back on.

With the new rear RCIC, although operator actions are not required, he has the capability to go in there and say, okay, I'm getting up toward Level 8 which means I'm putting in more coolant than I am steam and he could back down the fill rate so that it gets to the point that you are actually maintaining a pretty steady water level and the RCIC pump is not cycling on and off.

CHAIR ABDEL-KHALIK: Now, 800 gpm is a little less than 4 percent decay heat?

MR. BEARD: Correct. The sizing base is

the 800 gpm is such that should we have an isolation event with a scram with RCIC coming on at its predetermined setpoint that it will provide enough coolant such that we don't have water level drop below the next initiation standpoint which is where the high-pressure core flooders will come on and it will actually prevent it from dropping up one and then come back up. Nominally it is sized to match the decay heat load somewhere about 15 minutes after shutdown but the real basis is we don't want it to drop that Level 1.5 when the high-pressure core flow is coming.

MEMBER CORRADINI: So can you repeat what you said to start off this discussion which is you turned it to red because your analysis said that anyone of the legs can provide the electrical power for all the functions. That's what I heard you say. Did I understand it right?

MR. BEARD: No.

MEMBER CORRADINI: Okay. So could you repeat it?

MR. BEARD: There are five motor-driven pumps here. I've got motor-driven high-pressure core flooders, two of those, and three low-pressure flooders, LPFLs. Anyone of those five motor-driven pumps being powered is enough to get enough water into the RPV to ensure adequate core cooling.

MEMBER CORRADINI: Right. And any one train provides -- any one of the diesels -- unless I misunderstood, didn't you then say any one of the diesel generators provides the essential power for that?

MR. BEARD: Correct.

MEMBER CORRADINI: Okay.

MR. BEARD: The reason we never got to go into N-2 is because of RCIC. RCIC -- Dennis will talk to this in a lot more detail. When we certified RCIC was providing about -- let me back up. When we did the PRA for the certified design it turned out about 70 percent of our core damage frequency was the result of AC power events so RCIC is a real strong mitigator of loss of AC power events. It carries a very significant capability.

The later PRAs, as Dennis has been telling me, we've gotten that loss of AC power but not to be quite as dominant but still the dominant sequence but able to knock it down. What happens is when we start doing the N-2 game you say, "I've got an entire division out of service," and then you postulate that the single failure that you're going to look at disables another entire division of equipment.

Then if you say the initiating event is the ejection path used to return water back to the RPV in Division 1, the low-pressure ejection path, that does two things. One, it takes away my ejection path and, two, it depressorizes the vessel and takes away my motive force for RCIC. That is the one case where we can't say that we ran N-2.

MR. HENNEKE: This is Dennis Henneke, I'm a PRA. This diagram is really the start. When you look at why the risk on the ABWR is so low it really starts in this here. It's not just a three-train system. In most events, loss of feedwater event, typical reactor trip use high-pressure injection. You have to start with feedwater. If that is not available, you can go to high pressure. If that is not available, depressurize and go to low pressure.

Really what you're talking about here for most events are three trains with two possible ways to provide core protection. By increasing the defense in the high pressure and that combined with later on we'll talk about the AC power with three diesels and a combustion turbine and the addition of AC-independent water additional fire protection feed-in you are creating a lot more defense for the more typical events like a reactor trip or loss of feedwater event.

For the things that we have tried to mitigate by removing the recirculation pump piping, the large LOCAs, medium LOCAs, we have still adequate defense but we don't require basically six pumps for that design. You can keep that concept in your mind. This is really why the risk of the plant is so low. It's this full-defense event for almost all events.

MR. BEARD: That is a key point and I was going to emphasize that later. The three divisions of high-pressure capability really lend itself to the fact that for a lot of our transients and our small break LOCAs we never need to depressure the vessel. We could keep adequate cooling in the core and not have to go through that pretty significant transient of opening up the SRVs allowing the thing to blow down if the low-pressure ejection is going down. That is very significant.

Again, automated for 72 hours and for the analyzed conditions we never have the core uncovered with the ABWR. We get close but we never uncover the core. It's not like the ESBWR where we get a lot of water on the top of it. We never uncover the core and, therefore, very little core heat-up.

Next slide. Division of separation. I've probably spoken to this a lot already, Division A, B, and C. Those are kind of our mechanical things. Then from the I&C perspective you see Division 1, 2, 3, and 4 and basically the quadrant separation throughout the reactor building to achieve that.

Next slide, This is kind of rehashing what we talked about already but redundancy and diversity. Three divisions and each having both high and low pressure capability. The high pressure capability, two of those divisions have motor-driven high-pressure core flooder, PCF. Then the third division has a steam driven reactor core isolation cooling pump. Like I described, the reason we have that RCIC pump in there is to give us that substantial benefit when we start looking at loss of AC power events.

On the low-pressure side all three divisions we use the automatic depressurization system to bring the pressure of the vessel down. Then all three trains have residual heating removal system. The RHR actually is capable of operating in six different distinct modes. Three of those modes are safety related. There is the low-pressure flooder mode, the suppression cooling mode, and the containment spray mode.

When I get to residual heat we will talk about some of the improvements that have been made in the design of RHR relative to the operating fleet but also give us enhanced availability capabilities so that the bottom three divisions each division has both high and low-pressure capability.

Next slide, please. All three divisions are mechanically and electrically separated. Again, Dr. Shack will verify this. As part of the 93-087 and 90-016 they said no longer are you allowed to credit physical distance as a means of providing separation for fires. You need to put in three-hour fire barriers between your safety related trains. There is none of this 20 feet 6 meters worth of separation used to credit that a fire over on this cable tray doesn't take out this cable tray.

We do have entire physical separation between our mechanical and electrical for all three of our safety-related trays. That is for the core cooling function heat removal and the emergency diesel generators.

MEMBER SIEBER: Now, is that separation, physical separation, part of the building structure or some kind of, I shouldn't say it, but thermal like kind of reactor?

MR. BEARD: No. It's reinforced concrete partitions with fibers through and fire seals wherever we have --

MEMBER SIEBER: I assume the three-hour barriers consist of-

MR. BEARD: Yes, you can. With the exception of possibly one or two places in the control building we are not using steel studs and three layers of sheetrock on either side to get that barrier. We are using masonry construction.

MEMBER SIEBER: Where are your exceptions?

MR. BEARD: I think they are in the control building. They may have been eliminated since I last saw the design.

MEMBER SIEBER: Cable spreading or something like that?

MR. BEARD: There is no cable spreading per se but some of the back panel areas might have had barriers put up in them. I just don't remember.

MEMBER SIEBER: Somehow I remember Carlyle Michaelson worrying about your ventilation system and you smoke between the three divisions.

MR. BEARD: Yes. To address that -- thanks for bringing up those painful memories -- a lot of issues that Carlyle, a dear friend, brought up, one of those being propagation of smoke. The HVAC system for the reactor building and control building is set up such that should we experience a fire in a divisional area we will bring that area in negative relative to the other surrounding areas and we'll slightly pressurize the surrounding areas to we believe eliminate but it certainly minimizes and mitigates the propagation of smoke from the affective division to the nonaffected division.

MEMBER SIEBER: Is that automatic or just --

MR. BEARD: That is automatic.

MEMBER SIEBER: What do you do, trip a --

MR. BEARD: Yeah. Typically what we do is -- I'm trying to remember back here all the details. I think each one of those division areas have two supply fans, two exhaust fans. We trip the supply fan to the affected area. We start the standby fan of the affected area and we start the standby supply fans to the nonaffected areas.

MEMBER SIEBER: Okay.

MR. BEARD: Then there is some repositioning of the dampers. Station blackout, as I said, by rule we are classified as a alternate AC power plant being the combustion turbine generator is what satisfies the station blackout. Having said that, steam driven RCIC pump certainly provides us with a lot of capability. As Dennis indicated, we also have built into the plant hard-piped connections to the off-site fire protection system which also allows to directly eject water into the RVP.

MEMBER SIEBER: What is the size of the combustion turbine generator?

MR. BEARD: The combustion turbine generator is nominally 20 megawatts.

MEMBER SIEBER: If your diesels fail that could be used?

MR. BEARD: Yeah. It has the capability at an absolute minimum to power two of the three trains in reality with careful management by the operators that can power all three.

MEMBER SIEBER: Okay.

MR. BEARD: If the diesel generators operate then we use combustion turbine generator again like the ESBWR to power our plant investment protection modes.

MEMBER SIEBER: Okay.

MR. BEARD: Lube oil pumps and things like that. It is serving a dual purpose. Part of the reason is there for plant investment protection.

However, if none of our diesels start then we can power up the other.

MEMBER SIEBER: Is that repowering automatic or is it operator-actuated?

MR. BEARD: I do not remember.

MR. HENNEKE: Of the emergency vessels for CTG?

MR. BEARD: PIP bus transfer.

MR. HENNEKE: Oh.

MR. BEARD: If the diesels fail to start does the PIP bus automatically connect to the diesel busses?

MR. HENNEKE: I don't know that. I know the CTG has a manual alignment to the failed emergency vessel.

MR. BEARD: So it is a manual action. The CTG itself does auto-start on loss of off-site pumps.

Okay. One of the improvements with the RHR system is the suppression core infarction is automated. Earlier designs the heat exchanger was not normally valved into the flow path. This is something that the operator went through to valve in and pull water through the heat exchanger. With the design of the ABWR the heat exchanger is always on the flowpath so whenever we turn on the RHR pumps we are taking heat out of the water that was circulating through.

Next slide, please. That eliminates some of the complex transfer modes that we have. It also helped us reduce the valves and piping by about a third. It also helped us to reduce the required capacity significantly. The duty during transients, like I said, N-2 capability at high pressure. High pressure we are characterizing either as an isolation event or a small break LOCA. Any of the three high pressure capabilities can handle those transients so N-2 capability at high pressure.

What does that help us do? It helps reduce the need for ADS although we do have substantial capability. No fuel uncovery for any of the pipe breaks that we look at. And then to address the ISLOCA considerations, it started to become a prominent concern late in the certification process.

GE committed to an analysis that would demonstrate that the design pressure was at least 40 percent of the operating pressure of the RPV and the justification for that was that at 40 percent of 1,040 so nominally 450 pound design pressure. If you should ever expose that piping inadvertently to radio reactor pressure that we would not rupture the pipe, it might go into yield conditions but we would not rupture and create a LOCA scenario.

Next slide.

MEMBER MAYNARD: With the heat exchanger for the suppression pool always in the system, does that mean the RHR could be doing flections at the same time?

MR. BEARD: Correct. What it really means is -- this is a great slide to bring that question up -- if we've had to depressurize and we are using low-pressure flooder, we poor water out of the suppression pool with the pump, push it through the heat exchanger, and then return it back to the RPV.

MEMBER CORRADINI: And before they had to valve that in?

MR. BEARD: Before they had to valve that in. Initially we would bypass around the heat exchanger. We were just pulling water out of the suppression pool and then ejecting it into the RPV and then the operators had to go through the alignment process to valve the water in there and get the closed cooling water running on one side and the other side running on the other.

Probably a 10-minute evolution. This is all set up so that it's sitting there doing that normally. Then we start to pull water with that pump and it goes through the heat exchanger. Then there are various return paths depending on what we want it to be doing.

MEMBER CORRADINI: What was the logic that it was originally chosen to be valve done?

MR. BEARD: I think probably -- I think in part because they are carbon steel heat exchangers there were issues with corrosion products that they didn't necessarily want to get flushed into places until they determined they really needed the heat removal capability.

MEMBER CORRADINI: And now the material is different?

MR. BEARD: The material is different. We recognize the safety benefits of doing that. Certainly there are corrosion products in there but because we do use RHRs for shutdown cooling in this design, but before we do that we'll flush out the heat exchanger and all the piping before we actually connect it to the RPV to do shutdown cooling operational changes and some safety considerations.

MEMBER CORRADINI: The heat exchanger you made mention the materials are different. What is the material now, carbon steel?

MR. BEARD: I think it's still a carbon

steel shell but we may have gone to a corrosion-resistant tube. Okay. The three trains, train one with the RCIC pump, train B, high pressure and low pressure and the same thing over here. The high-pressure pumps whether it be RCIC or the high-pressure core flooders preferably will draw water from the condensate tank. The reason for that is condensate storage tank is high-grade water.

High-pressure systems are there to respond to transients. If we are going to be injecting water with the ECC systems we prefer that it be of a high grade. However, the CST itself is not a safety related structure so all three -- actually all six pumps also have the capability to take suction from the suppression pool and will put that water back in the RPV. Now, as I said, preferably sucking off the condensate storage tank.

At some point based on either low-level in the condensate storage tank or elevated water level in the suppression pool those high-pressure pumps will automatically switch over to suction directly from the suppression pool but that shouldn't occur for at least eight hours if everything is normally aligned. There are also provisions that the amount of water that is dedicated within the condensate storage tank is enough to ensure, I believe, eight hours of injection for isolated RPV.

That was accomplished by having a standpipe in the condensate storage tank. For all the other uses in condensate storage they could only draw down to a certain level and then the bottom part of the CST was reserved for the high-pressure pumps.

CHAIR ABDEL-KHALIK: What is the capacity of the condensate storage tank?

MR. BEARD: Nominally it's about 500,000 gallons. My recollection is if you did the math I think we have 180,000 gallons per minute dedicated by the standpipe.

CHAIR ABDEL-KHALIK: 180,000 gallons?

MR. BEARD: Yes. We were assuming we were running that 800,000 gallons a minute continuously through that eight hours.

Next slide. This is a more complicated figure of that but it shows the various modes of operation for all these pumps and systems. You can study that at your leisure. One of the modes that I hadn't talked about yet is the HRH systems do have the ability to spray the supper drywell as well as the lower drywell. Two of the three trains actually have that capability. Not all three trains do.

Another mode that we talk about fuel pool cooling support. One of the changes again that is being made for South Texas is that is has been increased so all three trains can now provide support for the fuel pool cooling system. The certified design only had a cross connected to two.

That is a manual alignment that occurs. The reason for that is the spent fuel cooling system is not safety related so that if we were in an extended period where we didn't have spent fuel pool cooling for whatever reason we can use RHR to remove the decay heat from the spent fuel pool.

MEMBER CORRADINI: I've been looking at the curve. Tell me again the last part of what you just said, that you can use the orange RHR-1 or Division 3 to cool the fuel pump? Is that what you just said? I'm sorry.

MR. BEARD: Well, I've got to get myself oriented here.

MEMBER CORRADINI: The orange is the one that's got the black line connected to the orange?

MR. BEARD: It may be in the interest of simplifying the design we don't show the connection from the fuel pool down to the RHR suction but there is a line that would come down here and then allow us to pump the water through the heat exchange and then return it back. That exist on two -- in the certified design that exist on two to three trains. South Texas is committing that would be available for all three trains.

Next slide. I'm going to put my marketing hat on just for a second. Mark asked me not to do too much marketing but this is not a paper-designed plant. We've had several built. We are building them in Lungmen so that is a 3-D that you are looking at there of all the safety-related piping or ESF piping. We have done all the calculations, all the routing.

We know what the penetrations are through floors and walls. We know where all the hangers go. We know all the bend radiuses and all the materials. This is not a paper design and that is one of the reasons South Texas chose the ABWR was when they felt they could get to commercial operation very quickly with very little risk.

Next slide. I'll take my marketing hat off.

CHAIR ABDEL-KHALIK: Okay. We'll remember what to ask when you put on your ESBWR hat.

MR. BEARD: Okay. So I'll spend just a little bit of time talking about the three different

ECC systems, reactor cooling, isolation cooling. Flow rate is 800 gallons per minute. That will be the case, the maximum flow rate for either the certified design using the old Terry turbine or the new design using the new rear pump, 800 gallons per minute capability as I described. That is based on making sure if I have an isolation event with nothing else going on that I don't get down below 1.5 to initiate high-pressure core flooder.

MEMBER CORRADINI: So just repeat, though. I want to make sure I understand the difference. The Terry turbine design is on and off the two flow levels. This Weir design that you said you were going to replace it with is variable flow up to 800 GPM.

MR. BEARD: Correct.

MEMBER CORRADINI: How is the variable flow handled?

MR. BEARD: That is part of the steam emission supply.

MEMBER CORRADINI: It's just a different valving?

MR. BEARD: The Terry turbine operated it at two speeds. The Weir pump can operate at multiple speeds so that is just adjusted by positioning the steam inlet valve to the turbine itself.

MR. HENNEKE: Some of the PWR auxiliary feedwater turbine pumps are Weir pumps designed for many years. They have been used in that mode.

MEMBER SIEBER: The control system --

MS. BANERJEE: I'm sorry. Jack, did you have a question?

MEMBER SIEBER: Yes. The control system for that is governor and what you are doing is changing the set point on the governor?

MR. BEARD: I have to plead that I'm outside of my area of knowledge.

MEMBER SIEBER: You aren't just changing the valve position in the setpoint?

MR. HENNEKE: I'm not sure either.

MS. BANERJEE: I was just wondering you said no operator action required for the first 72 hours. How is this adjustment made?

COURT REPORTER: Can you use the microphone, please?

MS. BANERJEE: This is Maitri Banerjee, ACRS staff. I was wondering about the 72 hours initially not requiring any operator action. How is this adjustment made to the RCIC flow?

MR. BEARD: The answer is, like I said, the 72-hour automated capability is we don't require operator action. We don't prevent it. This is a case where if we had an isolation transit, let's say, the pump comes on at 800 gallons per minute. I'm steaming, steaming, steaming. My water level is going to drop and it's going to be probably 45 minutes to an hour before I start to refill that and start to come back up to the trip setpoint.

In that 45 minutes the operator certainly has had time to analyze what the transient was, what is the status of the plant. He can now make a conscious decision do I want it to go up and automatically trip off on high level and restart when it gets down to level two again or do I want to step in and adjust the flow rate such that I start to try and get to maintaining water level at my normal operating level.

That is what it is. It is going to be an operator action recognizing filling the vessel and getting up toward my trip setpoint. I want to prevent that. How do I do that? I'm going to rachet back the flow rate.

CHAIR ABDEL-KHALIK: Isn't this a nuisance thing for the operator that he has to adjust the flow continuously by monitoring the level?

MR. BEARD: No, I don't think it's a

nuisance thing at all. I mean, it is going to be once you get close you allow it to swing several feel before you worry about it. I'll set it to one point and I'll see water levels start creeping up and so I'll dial it down so that I see it start to drop. Like I said, 45 minutes to an hour into the event it should pretty well stabilize at that point if you've ever sat on one of these simulators and it got to that point. The really exciting stuff is in the first 30 seconds.

MEMBER SIEBER: Before you get to the question I asked which is the control valve or control governor, the third question which I didn't ask because the first one couldn't be answered does the signal system look at basically level or does the operator actually have to occasionally adjust it?

MR. BEARD: I think the answer to your third question is it is definitely intervention. There is no feedback from vessel level to the control circuitry.

MEMBER SIEBER: More than likely since it's an inexpensive some kind of automatic system.

MR. BEARD: Keep in mind, too, that we are crediting RCIC as a substantial part of station blackout so we don't want unnecessary electrical bleeding the batteries. If I had to instrument all that and provide that as part of my feedback loop, I'm going to be chewing up my DC batteries pretty significantly.

MEMBER MAYNARD: If the operator takes action to adjust the flow, reduces flow, and then something comes up, he gets busy, the level goes down, hits the setpoint, will that kick back to al higher flow automatically?

MR. BEARD: Dennis, do you know the definitive answer? My understanding is yes, it would do that. It would retrip to its full or reinitiate to its flow rate.

MEMBER MAYNARD: If it didn't, it would be a situation where it would no longer be controlling it.

MR. BEARD: I can't say with 100 percent certainty that is the case but that is my understanding of the design.

MR. SAVAGE: This is Joe Savage of GE Hitachi. Let me read just a little bit from the RCIC turbine pump departure which, of course, we'll talk about some more later. I think it answers some of the questions you all were asking.

The pump is supported on a pedestal,

fabricated steel base, formed by a pump casing with essential water chamber. The monoblock construction of the pump eliminates the need for alignment between pump and turbine. The operating state of the pump is governed by the turbine control subsystem which regulates the quality of staying to the turbine based on discharge pressure.

The main elements of the control gear are the steam stop valve, the throttle valve, and the pressure governor. The pump is also provided with electrical and mechanical overspeed trip mechanisms which close the steam stop valve when the speed exceeds predetermined levels and speed measurement is provided constantly by an electronic tachometer.

MEMBER SIEBER: That really doesn't answer the question but thank you. I read that, too.

MR. BEARD: We will take the answer to find out the answer and communicate it back.

MEMBER SIEBER: All that says is you are controlling the governor and you are still going to get variations in level. You are going to have to do something about it from time to time.

MR. BEARD: Certainly if that is not the case we are going to get the common affect from the ACRS and we will go back and fix the design and we say thank you.

It is an AC independent system. There are batteries within the division in an electrical supply system to power that. We are using steam for the motor force. It does mitigate station blackout as I've said a couple times before. By rule we are an alternate AC power plant. We are not an AC independent power plant.

Two water sources, suppression cool which is the safety but the preferred suction off the condensate storage tank. Like I said, there is dedicated water within the CST for eight hours of operation of the RCIC turbine.

The other benefit of the new RCIC turbine is it is much more tolerant of elevated water temperature being pulled into the pump. It is a self-cooled pump. we are using some improved lubricants in it. Just the tolerances on the clearances and all that we can move a lot hotter water with the new Weir pump than we could possibly do with the old Terry turbine.

MEMBER SIEBER: The topical report says it has no internal seals. How do you keep the lubricant from getting into the water?

MR. SAVAGE: This is Joe Savage of GE

Hitachi. It is water protected. All the lubrication is water proof.

MR. BEARD: I was talking more of the turbine side.

MEMBER SIEBER: It's all one block. Everything. The bearings should be water. It's a canned pump in effect.

MR. SAVAGE: Yes.

MR. BEARD: Next slide. Just graphically this actually is the old Terry turbine because the need for the small bypass is no longer needed with the new rear pump. We pump into one of the main steamlines for steam supply and you have continued isolation valves but then going upward and then the stop valve here. Normally we have steam up to the stop valve. We open up the stop valve.

It's not shown on here but the control valve and steam introduced to the turbine, most of the energy extracted from the steam, and then the resulting steam is exhausted through a quencher/sparger that is located in the suppression pool and that piping comes out inside the room where the RCIC pump is actually housed. It spins the pump again taking suction either from the suppression pool or from the condensate storage tank and then check that water back to the RPV using the B feedwater line.

CHAIR ABDEL-KHALIK: You said the bypass line is not needed for the new model block?

MR. BEARD: That's what I said. Let me look at it because I noticed Dennis Henneke. Is that not true?

MR. HENNEKE: I don't recall. It wasn't in our model so.

MR. BEARD: One of the issues with the Terry Turbine was it had a tendency to overspeed when you first started it up so that is why we had this in. My understanding the Weir is must less likely to overspeed so we don't need that bypass.

MEMBER SIEBER: The reason for that is, and you're going to have it with this one, too, if it isn't heated you don't have some flow through there, a little bit of flow, it will cool off and you will condense a slug of water in there. Then when you open the valve that slug of water will go through the turbine and expand and you are going to get a big kick out of it.

There is no difference between a Terry turbine and a can turbine in regard to the steam conditions coming in. You probably have done something to keep the line hot and that is from the bypass down to the turbine but it's not shown there.

MEMBER CORRADINI: You would probably change the point of the valving, wouldn't you?

MEMBER SIEBER: You probably have a bypass valve in there some place.

MR. BEARD: We can check into that. Then the other significant element is there is a keepfill pump located here taking water from the suppression pool and making sure that we keep the discharge line always full. That is relying on safety related electrical power to operate that pump the theory being for the short period of time of you are in a station blackout before this pump initiates not much of that water will drain back through the check valves. That is help minimize or eliminate water hammer event when you first start this pump up.

Next slide then, please. Okay. RCIC was one of the three high-pressure capability and then we have the two motor-driven high-pressure core flooders. At rated reactor pressure they are going to deliberate how many gallons per minute but they are not a fixed volume flow so as the back-pressure on the discharge falls off as we get down to a depressurized state, that flood will increase to 3,200. Why is that significant?

It says not only am I handling small-break LOCA up to 800 gallons per minute. Even if I get LOCA sizes that are larger than that and I start to depressurize the vessel, the flow rate out of my high-pressure core flush is going to increase and, again, may help us to avoid having to depressurize the vessel. Or if we need to depressurize it, that is 727 meters cubed, 3,200 gallons per minute, again is sufficient in and of its own right to provide adequate core cooling.

CHAIR ABDEL-KHALIK: So this is the run-out capacity of the pumps?

MR. BEARD: Run-out capacity of the pumps, yes. They have a very wide operating range. It just dawned on me that it's not on these slides. I don't think it's on the next slide. One of the PRA insights that we gained was we have a commitment that we have to do, I believe, a factory test or at least a factory analysis that even if the suppression pool water temperatures are elevated that we need to be able to move at least half of the rated flow using these motor driven pumps.

There is some net-positive suction net calculations and cavitational considerations that go into that particular design. That was, again, if we had for whatever reason degraded heat rule for the suppression pool we still had capability to at least move some water using these high-pressure core flooder pumps even though the temperature of the suppression pool might be significantly elevated. Same as RCIC preferred from the condensate storage tank because the safety body of water is considered to be the suppression pool.

Next slide. Mr. Chairman, did you have a break built in anywhere?

CHAIR ABDEL-KHALIK: 2:15.

MR. BEARD: 2:15. Okay.

CHAIR ABDEL-KHALIK: Is there a convenient time?

MR. BEARD: No, I was just wondering. High pressure core flooder. Very simple, take water and throw in the condensate storage tank or from the suppression pool and inject it up into the RPV. You will notice that the standby liquid control line, at least one of them, connects into that same flow path to allow the injection of sodium pentaborate into the RPV using the sparger assembler that is located with the high-pressure core flooder.

MEMBER SIEBER: That is your ATWS mitigation?

MR. BEARD: That is part of our ATWS mitigation, yes. We don't need that additional volume for cooling like we do on the ESBWR. That was all I need to talk about on that.

Next slide. So residual heat removal. The three low-pressure flooder pumps, as I indicated earlier, six months of operation. Three of them are safety related. I think we have talked about these already. Then there are the nonsafety provisions, shutdown cooling, fuel pool cooling support.

It also provides the flow path that we are going to use for what we call the AC independent water addition which is a very fancy word for fire protection injection core path capability. We liked that in ISAC when we had ACIWA. The RHR does provide the flow path for that water to be brought into the containment and then to the RPV.

Next slide, please. So RHR recirculates and cools the water inside the primary containment and is doing that by taking suction from the suppression pool. That is normally a live suction path for the RHR pumps and then the water has it pumps through there goes right through the heat exchanger.

Three motor driven pumps deliver 4,200 gallons per minute when the vessel is depressurized.

Single pump in operation assures that we have no core damage, again going back to the point that I made earlier that any one of the five motor-driven pumps in and of itself provides sufficient flow into the RPV to assure that we have adequate core cooling all in one water source and that is the suppression pool and it is a safety related water source.

CHAIR ABDEL-KHALIK: What is the shut-off head for these pumps?

MR. BEARD: I think it's like 100 psi but they are very low pressure. Total developed head is something on that order.

MEMBER CORRADINI: I was guessing. I just remembered the RHRs would shut off at 250 or something like that.

MR. BEARD: There is the issue of when do we isolate it when we are using it for shutdown cooling which is a slightly different issue because the total developed head is still maybe now I've got 800 psi coming in but the total developed head across the pump to my recollection is somewhere around 100 psi.

Next slide, please.Not as clean as some of the other pictures I had but this does talk to the fact it has multiple modes of operation. Primarily taking water out of the suppression pool through the pump, through the heat exchanger. We are giving up that heat to the closed component cooling water system, RCW. RCW will then transfer that water or that heat to the RSW, the reactor service water system, and then it will be discharged into the environment through the ultimate heat sink so there is an intermediate heat removal loop here.

The various points once we take that water out of the suppression pool that we can do is turn it back to the suppression pool which gives us a full-flow test capability. We can spray the wetwell airspace and spray the drywell airspace. We can inject it back into the RPV. We can close this valve and use it for shutdown cooling so we come out through a series of isolation valves.

Come down through the pump through the heat exchange and then return it back to the RPV. We can take water from fire protection whether it be from the normal fire protection system on site using the permanent fire pumps or through a connection where a fire truck pulls up to the outside of the building that it connects into but allow us to bring water into the reactor building.

Again, primarily we would probably be

flowing into the RPV but also has the capability if we want to spray the drywell to wetwell we could use that water to do that. Then the cross connect, the fuel pool cooling and cleanup system again manually aligned but you bring water from the fuel pool cooling and cleanup system.

This would be the water from the surge tanks. It would come down and would be routed by opening these valves again through the RHR pump suction through the heat exchange and then return back up to the upper parts of the reactor building.

CHAIR ABDEL-KHALIK: Now, the keepfill pumps are running continuously. Is that correct?

MR. BEARD: Correct. They are running continuously when the pump is not running.

CHAIR ABDEL-KHALIK: Right. And when --

MR. BEARD: When it's in standby they would be running, yes.

CHAIR ABDEL-KHALIK: Where do they get their power?

MR. BEARD: From a safety-related busses. They are part of the 1A power supply. Let me go back. I seem to recall after I said that that maybe that was not the case but I don't remember.

CHAIR ABDEL-KHALIK: Is this a good spot

to take a 15-minute break?

MR. BEARD: This would be a wonderful spot to take a break.

CHAIR ABDEL-KHALIK: We'll take a 15-minute break. We'll be back at 2:35.

(Whereupon, at 2:17 p.m. off the record until 2:36 p.m.)

CHAIR ABDEL-KHALIK: We are back.

MR. BEARD: Okay. During the break Dennis Henneke went back and did a little bit of homework for me. On the RCIC pump the bypass does still exist. I'm probably recalling talking about that we thought we might be able to eliminate it and I guess we determined we couldn't.

I think we finished discussing this slide so if there are no other questions, I will move on to the next slide. Automatic depressurization. Still need an automatic depressurization system. There are 18 safety relief valves on the ABWR just like on the ESBWR. Eight of those 18 and additional solenoid valves and nitrogen accumulators on them to provide an ADS function.

Two of the SRVs on each of the main steamlines is designated as part of the ADS system. They do blow down directly into quenchers in the suppression pool. All 18 SRVs in the ABWR do have pipes and corrections located in the suppression pool.

That is different from the ESBWR. In an isolation transient we expect all 18 SRVs to go open -- excuse me, 17 or whatever but all the SRVs to pop open for a short period of time whereas in the ESBWR they postulate. We believe that is never going to happen and that is the primary reason for that difference.

Spring safety mode, all 18 provide that. All 18 are also provided with extra --

CHAIR ABDEL-KHALIK: Why do you think 17 in this case will pop open and not in the case of ESBWR?

MR. BEARD: When we do the analysis we only need 17 of the 18 to open to handle the over-pressurization transient.

CHAIR ABDEL-KHALIK: And operational experience suggest that you will actually get 17 of the 18?

MR. BEARD: Because there are going to be six or seven that are all at the same setpoint. If we come up to the setpoint they are all going to go off. I keep making contrast to the ESBWR. I know that wasn't what you asked for but it's one that you must deal with lately.

All 18 safety relief valves on the ABWR also have a relief function so they are truly safety relief valves and eight of those 18 have the additional solenoids and the accumulators provide for the ADS pumps. We do have a preemptive relief capability on all those 18 valves that are phased in over different points to the prime limit depressurization transient.

Next slide then, please.

MS. BANERJEE: Can I ask a question?

MR. BEARD: Yes, you may.

MS. BANERJEE: This is Maitri Banerjee again. I was wondering if these safety relief valves are any different or improved compared to what we have in the current fleet of BWRs which have some problem with setpoints?

MR. BEARD: There is a mixture of valves on the current operating fleet. This is what we are using at K6 and K7 and what we were using in the later model of BWRs. I believe some of the BWRs have gone back to this particular type of valve.

Schematically automatic depressurization. Actually all 18 would have that. Vacuum breakers on the tail pipes coming off and then the steam coming down into the suppression tool. This also shows some of the main steam capability as well as the reactor head.

But focusing here on the safety relief valves you do have vacuum breakers on there so that we don't draw water back up into the tailpipe once we've had an opening of the safety relief valve. They are externally actuated. I think I took the slide out because I was trying to limit the number of slides.

CHAIR ABDEL-KHALIK: If one goes from 33 percent bypass capability to 100 percent bypass capability, does that require a redesign of some of this piping?

MR. BEARD: No, because we still have to handle the assumption that you have a turbine trip without bypass or an MSIV isolation. Those are the ones that -- no, it's the turbine trip without bypass that is the limiting pressurization transient because those valves go closed quicker than the MSIVs.

Although I have longer piping and some compressibility in there because of the rapid closure of those turbine stop valves, it actually is the one that results in the slightly faster pressurization transient although the MSIV closure is very close behind it.

CHAIR ABDEL-KHALIK: Okay.

MR. BEARD: The answer is no. The bypass capability really is not directly related to the sizing of the safety relief valves. In fact, what ends up sizing the safety relief valve capacity is the anticipated transient without scram and not the pressurization transient.

Next slide, please. BWR water level measurement. We did include in the reference legs and the variable legs, the provisions that we have in the ESBWR with the backfill to address the issue of noncondensable gas buildup in those reference legs. Very strict requirements on the pitch of the pipe from the RPV up to the condensing chamber and the pitch of the pipe within the reference legs to address the noncondensable issue that first surfaced at the Pilgrim plant.

We do have four divisions of water level instrumentation. Those four divisions are for narrow range and wide range which is where all of our safety-related inputs are coming from. Level 8 through Level 1 were all detected within the narrow and wide range and each one of those divisions feeds off information to its assigned division.

Some of the more important levels that we look at, Level 8, if we get to Level 8, which is a high level. We are starting to get up to the point that we might get water going down the main steam lines. We trip our main terminal and close our MSIVs and also get a scram on Level 8 as well.

Going on the low level because we normally operate around Level 4, if we get to the Level 3 the first protective action is we scram the plant. At Level 2, which is substantially below Level 3, the RCIC pump will start. At Level 3 we are still hoping that the feedwater system will restore water level and maintain it. If feedwater is not operating or is degraded for whatever reason, at Level 2 the RCIC pump will start.

Then if for some strange reason the RCIC either cannot restore level or fails to start if we get to Level 1 and a half two high-pressure core flooders are going to start. Then again if we are have a break of sufficient size or we have degraded capability here for whatever reason at No. 1 we will start into the sequence for low-pressure ejection which would be an automatic depressurization and auto-initiation of the LPFL pumps to eject water into the RPV.

CHAIR ABDEL-KHALIK: How does zero percent wide range compare to the top of active fuel?

MR. BEARD: Zero -- I'm worry.

CHAIR ABDEL-KHALIK: Wide range. When you get to the bottom of the wide range where is that?

MR. BEARD: The reference zero on this plant is top of active fuel. Is that correct, Dennis?

MR. HENNEKE: I believe so right now.

MR. BEARD: The instruments are set so that reference zero is TAF.

CHAIR ABDEL-KHALIK: The wide range would read zero percent at that point?

MR. BEARD: Yes. Actually, it probably goes a little bit below that. I don't remember exactly where that lower tab is on the RPV but I suspect it is slightly below TAF.

MEMBER SIEBER: If this drawing is accurate that would be the case.

MR. BEARD: That would be accurate. It does have a little bit of capability below. Then if we go into a place, you know, we shouldn't in one of our design bases accident do we get a below TAF but if we got in there then the fuel zone range in the event of a severe accident would be what be what we are monitoring water level within the RPV.

MR. HENNEKE: This is Dennis Henneke

again. The ADS Level 1 something came out of their early PRA study that we added in so that if you had a loss of feedwater but didn't have a break you actually depressurized --

MEMBER SIEBER: So there are four taps per division.

MR. BEARD: Correct. There are four reference leg taps, there's four narrow range taps, there's four wide level range taps.

MEMBER SIEBER: In the fuel zone.

MR. BEARD: Fuel zone I believe is only two. Dennis, do you remember? I believe we only have two because there is a much safer way to trip functions coming off of those taps instead of operational information

Next slide, please. Dennis will probably talk to some of this but I just wanted to put up one of the things that significantly differs from the existing operating fleet is we still have a plant on paper so we went back and looked at it and said what are some things we can do although we don't believe we are ever going to have a severe accident. If we do, what are some of the things we can do. This slide just illustrates some of the things that we believe provide us with the substantial capability to mitigate severe accidents.

The first of those is a commitment at the bottom of the lower drywell that we will for 1.5 meters we are going to use the basaltic-based concrete meaning granite. The reason for that is if we do have a core melt and we have core exist the vessel and using the basaltic concrete there is less noncondensable gases generated in that core reaction so there is commitment for 1.5 meters of concrete fill there above where we might have a limestone aggregate-based concrete.

The drywell equipment sumps that we talked about earlier there are two located down in the lower drywell. They are out on the periphery of that but there was an issue that we looked at potentially where we would get corium exiting the vessel and then that corium would translate across here. We were concerned about corium getting down here and creating a local attack. We came up with a design that uses a refractory material with what we call freeze channels.

As the corium progresses down those freeze channels against the port there is not enough heat being generated and they actually freeze and prevent the corium from getting into the sump itself. We have the lower drywell flooded, the LDF.

There are eight of these thermally activated valves such that if we do have a core melt accident and we get core relocated to the lower drywell, the air temperature in this area will go up, those fusible links will open up and allow gravity to drain the water from the suppression pool to cover the top of the corium debris to provide some cooling.

The spreading area provided down here is in excess of the criteria that was developed as part of the utility requirements document, the .02 megawatt. .02 meter squared per megawatt thermal I will indicate the NRC staff has never endorsed nor denied that basis but we do commit to having the minimum spreading area in conformance of the EPRI utility requirements document.

Then, finally, in the event of a severe accident we don't want the containment to fail. We want to go ahead and if we are getting to elevated pressures engineer where we are going to have the failure of the containment. Also we have the containment overpressure protection system, COPs as we call them.

It uses some ruptures disks. We chose to provide that depth from the wetwell airspace. The reason for that was at least we would get credit for filtering and pushing all that debris down through the suppression pool so that we don't have at least particulate debris and we are still getting a fair amount of iodine.

CHAIR ABDEL-KHALIK: Are these features part of 4 DCD?

MR. BEARD: Yes, they are part of the certified design.

MEMBER CORRADINI: And they are built into the Japanese plant?

MR. BEARD: I don't believe --

MEMBER CORRADINI: I want to know are they built into the plants in Japan?

MR. BEARD: I don't believe that is the case but I don't know that for certain.

MEMBER CORRADINI: But they would be in the South Texas project?

MR. BEARD: The COL application should have incorporated by reference this part.

MEMBER CORRADINI: Is the lower drywell planned to be dry?

MR. BEARD: Yes. It is our --

MEMBER CORRADINI: So you have it designed so there is no water leakage below the skirt of the vessel and onto the lower drywell floor?

MR. BEARD: Right. The ABWR has a solid support skirt unlike the ESBWR so where this comes down to that there is a solid connection between the vessel and where the vessel is matted to the pedestal wall. Any water that might be leaking up here would not migrate down to the lower drywell. Only water sources in the lower drywell would stop breaks down below the skirt.

MEMBER CORRADINI: Then it piles up on the skirt?

MR. BEARD: Piles up on the skirt to the point that it fills the annulus and then would start to spill down the connecting vessel.

MEMBER BONACA: How distant is the bottom of the vessel from the top of the basaltic?

MR. BEARD: The distance from the bottom of the vessel to the top of the basaltic concrete is going to be on the order of 28 to 33. The CRD housing sticks down and then we have to have room to move the CRD mechanism and tilt it on its side and transport it out for maintenance. It is about 28 feet from there down to the top of the basaltic concrete.

MEMBER SIEBER: The height of the fusible valve determines how much water goes into it the chamber.

MR. BEARD: Correct. If we do have an actuation of the lower drywell flooder valves, although there is a solid skirt here and the connecting pipes come down this way there are openings in the pedestal wall below the skirt that tied into the connecting vents such that when we are steaming in this area that steam would go up and back down and then exhaust back out into the suppression pool so we have that.

To your point earlier, Dr. Seiber, the position of these is such that even if we open all these valves we still maintain enough water in the suppression pool that we never uncover the horizontal vents.

MEMBER CORRADINI: I guess from -- Jack is asking the question and I guess I was thinking about from a water inventory standpoint the skirt is impervious enough so water doesn't get down but it is permeable enough the steam can get out?

MR. BEARD: No.

MEMBER CORRADINI: So where is the steam getting out?

MR. BEARD: It's a different flow path.

MEMBER CORRADINI: So where is the steam getting out?

MR. BEARD: There is a vertical pipe coming down here with the horizontal vents.

MEMBER CORRADINI: Oh, it would blow back into the wetwell.

MR. BEARD: Yes. There is an opening below the skirt into the connecting vent to allow the steam and lower drywell to connect into the connecting vent.

MEMBER CORRADINI: Okay. Then what is the water depth once these fusible links open?

MR. BEARD: Over the corium?

MEMBER CORRADINI: Yep. Is it halfway up the 30 feet? Is it a quarter way up? I'm just curious.

MR. BEARD: It's no higher than what the suppression pool is and I believe the suppression pool is 7 meters in depth. It is probably, and I'm just estimating, 4 or 5 meters.

MEMBER SIEBER: It wouldn't come up to the bottom.

MR. BEARD: Correct. It would probably come up just about the equivalent of platform level.

MEMBER CORRADINI: So one last question. From a design standpoint to put in a fusible link versus allowing water to penetrate, what was the logic there?

MR. BEARD: The logic was it was entirely passive. We figured that one of the dominant sequences for getting us to a severe accident was failure of our digital control systems. Having addressed that we took the digital control systems out of the picture.

MEMBER CORRADINI: No, no, no. Maybe I didn't ask my question correctly. What I guess I'm saying is the skirt doesn't allow water down. Yet, you put in a design to allow water to come in through the wetwell. Why not simply allow the water down from the very beginning?

MR. BEARD: Steam explosion.

MEMBER CORRADINI: Okay.

MR. BEARD: We don't want to be dropping hot core debris into a subcooled body of water.

MR. HENNEKE: Also post-core damage the PRA gave severe accident guidance. If you are adding water to cover a melted core below the vessel not to raise it like some of the plants that cover around your entire vessel but only to the bottom of the vessel so that COPs continues to work even at that point so fission products are scrubbed through the suppression pool. Later on if you need to do some cleanup or whatever then you can flood up but initially the flood level begins at the bottom of the vessel to keep COPs available.

MEMBER CORRADINI: We are going to come back to this with other drawings later?

MR. BEARD: No.

MEMBER CORRADINI: So let me ask my last question one more time. Nothing worked and it's sitting down there. The fusible links open up. I have got water. It's now steaming and the steam goes where? What is the path?

MR. BEARD: Here is the connecting vent. Therefore, we call it the spillover pipe. There is the solid skirt right there. Water can't go beyond that point so I can fill up there and spill back over but it doesn't come down here.

MEMBER CORRADINI: And spills over -- I'm sorry. I see the skirt. It spills over above at that nozzle up here. Right?

MR. BEARD: Yep. When the lower drywell flooders actuate they flow water over top of the corium debris and we start steaming. That steam comes up and transfers through the spillover vent and then goes back down.

MEMBER CORRADINI: Okay. So it actually

enters those 10 tunnels that go into -- the 10 pipes that go into the wetwell.

MR. BEARD: Yes.

MEMBER CORRADINI: Okay.

MEMBER SIEBER: The vent.

MR. BEARD: Right. Or it could go up but you get a pressurize to the point that you start pushing steam back down.

MEMBER SIEBER: It's all going to come to equilibrium.

MR. BEARD: Correct.

MEMBER CORRADINI: Okay. Thank you.

MR. BEARD: Yep.

MEMBER CORRADINI: Appreciate it.

MR. BEARD: Can you find where we were?

MEMBER CORRADINI: 39.

MR. BEARD: Any other questions? Next slide, please. I'm going to speed up a little bit because I don't think there is a whole lot here. One of the other design improvements or, at least, design changes in philosophy is the safe related component cooling water and service water in the system, with the ABWR those systems are normally operating.

We are removing a lot of our process heat using our safety-related systems. The benefit to that is those systems are running so that when we get into an accident we don't have to call a system into operation that hasn't been operating or already in operation but getting a lot of use from the work. That is a significant departure from the earlier models where we had these safety-related systems but we were using non-safety service water and non-safety component cooling water to remove most of our process heat modes.

In this case the process heat modes were removing spent fuel pool cooling. We are getting chilled water that is being cooled by these systems. The reactor water cleanup system is rejecting its heat to this system. HVAC using the chilled water is exhausting heat out through the system. Those are the primary ones. The diesel generators when they are running will be ejecting heat to the reactor service water system.

These systems are normally in operation. The difference is when we get to an accident or transient while we might have had one pump running out of two, we will start the standby pumps for the full capability of the particular system.

Next slide. A lot of this I already talked about, some of the nonsafety systems that are being cooled by the reactor component cooling water system. During normal power operation they would be isolated on a LOCA signal, things like the reactor internal pumps or reactor water cleanup system, drywell cooling and fuel pool cooling cleanup. Each system has some heat exchangers and two 50 percent pumps.

Like I said, normally one is operating and if you get a LOCA signal the second pump would automatically start. The reactor service water again same type of setup. The reactor service water system there is a reference design included in the DCD.

CHAIR ABDEL-KHALIK: So what is being cooled in the RIPS? Aren't they self-cooled?

MR. BEARD: No. There is a heat exchanger not in the housing but we take water from the housing, circulate it through the heat exchange and put it back into the housing. That water is actually circulated by a differential pressure that is being extracted from the flow from the RIP itself. There is no external pump pumping it through that heat exchanger but there is a heat exchanger external to that housing to cool the water.

The water inside of that can is really not moving so it is absorbing all the heat from the RPV as well as from the RPV as well as from the electrical, the inefficiency of the electrical motor. There is a substantial amount of heat being deposited in that water when that pump is turning.

MEMBER SIEBER: The water is actually moving but it's not leaving.

MR. BEARD: There is a little bit leaving the pump because the CRD system we have a purge that is going in there. That is just to make sure that any movement of water is back into the vessel, that we don't have water coming from the vessel down into that. That is not the cooling. The cooling is taking that circulation out through the heat exchanger. Any other questions?

Next slide, please. Graphically this is what it would look like. Oh, I started to say the reactor service water system. Conceptually in the design certification we describe a reactor service water system that would use spray pond but it is quite clear, at least in my view, that it is not part of the certified design. That is just a reference of how the reactor service water system can do it. There are certain requirements imposed on the reactor service water system design.

The most important of those is the length of piping between the heat exchangers which are located in the basement of the control building out to the isolation point at the ultimate heat sink to be no longer than two kilometers.

That was set because we would assume that amount of water to potentially drain through a pipe break into the basement of the control building and the resulting elevation of that flood would not disable any of the equipment in the control building structure. Other than that, the only other provisions that are required are electrical and physical separation of the three trains.

MEMBER SIEBER: These pumps are outside the containment. Right?

MR. BEARD: These pumps are outside -- which pumps are we referring to, the RBCW pumps?

MEMBER SIEBER: Yes.

MR. BEARD: Those would be located on the base mount of the control building. Then the RSW pumps themselves would be out at the ultimate heat sink pump whether that is a spray pond or cooling tower or whatever. The RCW is a fixed volume system so there is a surge tank, head tank. There is some chemical ejection capability as well.

MR. HENNEKE: This is Dennis Henneke

again. The difference between a spray pond and a cooling tower I will get to in the PRA and that is actually the different designs do have different liability. Again, it was not part of the original DCD details. PRA analyzed the assumption of the spray pond and I'll get that when we get to the PRA section.

MR. BEARD: Excellent. On-site AC power. There are three safety-related diesels. Each one of those diesels is dedicated to a particular train. They are nonimally 7 MWe each, fairly large diesels, one per division. As I said, they are housed inside the reactor building at-grade elevation.

We also have one combustion turbine generator, nominally 20 megawatts electric. It would be housed in the electrical auxiliary building off to the side of the turbine building. I have already harped on that enough so I won't do it. CTG does autostart on loss of AC power to its busses. It automatically connects to the plant investment protection busses, the PIP busses.

Should diesel generators not start the operator does have the ability to disconnect it from the PIP busses and connect it to any one of the three safety-related busses or any combination of two. In fact, it probably has the capability to power all three busses.

Next slide. This is how it is configured. The operational busses are what we call the plant investment protection busses. The loss of AC power combustion turbine generator starts. Being it's a CTG it doesn't start and generate electricity right away. It's anywhere from two minutes to 10 minutes before we are actually up to the point that we can generate electricity. It preferentially connects to the plant investment protection busses. Then if the diesel generators fail to start, the operator can disconnect these and then close these breakers to power up those busses.

Sequencing of loads on the diesel generator busses is only based on electrical power back on the bus and really doesn't have to do with any of the breaker coordination as to where that power is coming from. Whether it be the diesel generator or the combustion turbine generator, once that bus is reenergized the sequences start from that point.

MEMBER SIEBER: Are you expecting a reactor from a frequency standpoint between the diesel and the combustion?

MR. BEARD: No, they should never be connected. They should never be parallel. I don't know what the operational interaction is there but it is never intended that they be parallel.

MEMBER SIEBER: When the turbine comes on, that means what you said are the diesels are locked out?

MR. BEARD: If I've lost off-site AC power the combustion turbine generator will come on as well as the diesel generators.

MEMBER CORRADINI: But they won't be feeding the same loads.

MR. BEARD: They will not be feeding the same loads and they are not parallel.

Next. Okay. This is another design departure that the COL application is coming in with. In the DCD we describe a single medium voltage distribution system. When we got to detailing out the design, especially from Lungmen, it became apparent that we wanted a dual-medium voltage system.

We have adopted that as a standard. Should we submit Rev 5 it would come in with the medium voltage level and the STP COL application also has a medium voltage level very similar to the ESBWR in that we've got 13.8 KV as well as in this case a 4.16 KV medium-voltage bus.

The higher the medium voltage is for the large loads like the sump water pumps, feedwater pumps, those types of things, all the other large but not excessively large loads will be parallel to the 41.60 busses, things like the CRD pumps or turbine building cooling water. Then you see the safety-related busses down here as well, diesel generated and some loads of power as well.

MEMBER ARMIJO: Is this what you have used in the original Japanese ABWR?

MR. BEARD: This is not what was used. This is different.

MEMBER ARMIJO: Lungmen uses it?

MR. BEARD: Lungmen uses this design. The original Japanese design part of it was because the circ water pumps are very, very close to the actual turbine building. They didn't have long lines of electrical leads. Had a single 6.9 KV medium-voltage bus. Plus the Japanese plants use steam-driven feedwater pumps if I recall properly which is another one of the significant electrical loads in the design.

Couple of other points. Multiple reserve auxiliary transformers. They can be powered and connected down through this bus here to power to various combinations of plant investment protection busses and the safety-related busses. There is a commitment within the DCD that when we are -- normally we are powering the safety-related busses from off-site power. There is a commitment in the DCD to power no more than two of these busses from either the preferred off-site power source or the ultimate.

That means we are always going to have at least one of those busses connected to a power source to that is different than the other two. If you experience some sort of disruption on the grid on that side it doesn't take away all the power to the safety-related busses in that case.

Next. Standby liquid control system. Very similar to the existing fleet, two 100 percent motor-driven positive displacement pumps. Single common tank that we are using in rich sodium pentaborate. Some of the things that do happen, reactor water cleanup system will automatically isolate should we initiate the reactor water cleanup system or should we initiate the standby LOCA control system.

Dennis, correct me if I'm wrong, but standby LOCA control is automatically initiated in this design. That is another difference from most of the operating fleet in that our ATWS mitigation is automated.

CHAIR ABDEL-KHALIK: On what signal?

MR. BEARD: In this case it would be LPRMs not downscale in three minutes. I think it's three minutes. Pretty much the same basis as what we have for the ESBWR. We want to give the chance for the motion control rod drives if we've had a hydraulic failure for the motors to insert control blades before they reject the sodium pentaborate.

MEMBER SIEBER: How long does it take to pump it in, 20 minutes?

MR. BEARD: Somewhere in that time frame, yes.

MEMBER SIEBER: What happens in 20 minutes?

MR. BEARD: Yeah. In this case because it doesn't inject as fast as the ESBWR we are going to have continued steaming after the safety relief valves. Part of the ATWS mitigation is trip of the recirc pumps and the feedwater will run back as well to try and backdown power until the sodium pentaborate gets in there and takes the rest of it.

One of the bases for the sizing of our COPs flowpath was partly the ATWS mitigation in that it is sized for 4 percent, somewhere around there, so that if we do get to the point where we can extend an unmitigated ATWS event and we bring the temperature of the suppression pool up that as we steam up through that COPs disk that it is relieving pressure faster than we are adding it through the ATWS event.

Next slide.

MEMBER CORRADINI: Did you tell us where the COPs disk is being sent to? Maybe you did and I forgot.

MR. BEARD: I did not but it is through the ventilation ductwork out to the plant stack.

MEMBER CORRADINI: It is being filtered through something. Is it not?

MR. BEARD: No. There is no -- it is not going through standby gas treatment system or any kind of European filter. We are saying that because we are releasing from the wetwell airspace it's providing -- I was going to use the term sufficient. It is providing a significant filtration capability or, in effect, that we don't believe there is a 10 to -8, 10 to -9 type of event.

MR. HENNEKE: This is Dennis Henneke again. Bubbling through the water in the suppression pool, if that were to bypass, depending on the event release, out of containment would it be anywhere between 100 or 10,000 times worse than bubbling through the water.

MEMBER CORRADINI: So the decontamination factor is of that order?

MR. BEARD: Yes.

CHAIR ABDEL-KHALIK: You said enrichment is optional for the standby liquid control system on the previous graph?

MR. BEARD: Did I?

CHAIR ABDEL-KHALIK: That's what it says.

MR. BEARD: I didn't think it was.

CHAIR ABDEL-KHALIK: Okay.

MR. BEARD: I thought we were using enriched.

MR. SAVAGE: It might if it's based on megawatt-thermal because of its use?

MR. BEARD: No, because it would affect the tax size.

MEMBER ARMIJO: When water with sodium pentaborate boils, I probably should know this, but what happens?

MR. BEARD: The sodium pentaborate stays in solution. It does not boil off.

MEMBER ARMIJO: Does not boil off? Doesn't form a solid deposit on anything?

MR. BEARD: No. It stays in the RPV also

releases the steam.

MEMBER CORRADINI: But it only distills at colder temperatures.

MEMBER SIEBER: Is this enriched borate?

MR. BEARD: That's the question. I thought that we had committed to enriched sodium pentaborate but they are saying it's optional and I don't know the basis for that comment on the slide.

MEMBER SIEBER: Your topic says could be either way.

MR. BEARD: I'm not familiar with why they say it can be either way.

MEMBER ARMIJO: Bigger tanks.

MR. BEARD: Yes. SLCS reactivity requirements very much like what the conventional plants are but we do inject sufficient sodium pentaborate to ensure that we are subcritical all the way down to the cold shutdown condition with all the other negative reactivity facts taken into effect, or positive reactivity affects taken into effect.

Next slide. The initiations of the SLCS. There is a manual capability but, like I said earlier, it has been automated which is different from the existing fleet, at least most of it. We are looking at high RPV pressure or low water level. And, and that is a key and, the startup range neutron monitor is not being below 6 percent RTP for three minutes so very much like what we do for the ESBWR.

Next slide. Just graphically here it is, single common storage tank, two positive displacement pumps and then you have a parallel flow pass here , train A and train B. We are not going to assume a passive failure of the flow piping.

Again, the injection point ties into the high pressure core flooder B injection line. What I didn't talk about earlier is as that injection line goes into the vessel there is a short sparger that wraps around a portion of the radial part of the RPD and those nozzles are actually turned down and injecting the water down the annular space in the RPV up around the steam separator level.

We are introducing that sodium pentaborate out in the annular space and allowing the normal circulation to pull the sodium pentaborate to the lower head and then bring it up through the core to bring the reactor subcritical.

Next slide. We talked about with the ESBWR the fine motion control rod drives. The adoption of fine motion control rod drives really has eliminated a lot of the challenges that ATWS has done.

How is that? Because we no longer have the scram discharge volume and the exhaust piping. We don't have that potential hydraulic binding mechanism that was experience at Browns Ferry.

All of our hydraulic control units, high pressure control, insert lines only are going to overcome the pressure of the RPV and drive the rods in. The elimination of that scram discharge line really more than anything has taken a lot of potential mechanisms that can cause us to not insert those rods having the picture. Then we have the diversity where we do have the electric motors. Although they are not safety related, they are one of the two approved nonsafety loans on one of our diesel generator busses.

Even if we lose off-site AC power and we don't have the hydraulic scram occur, we do have the ability using the Div 1 diesel because that does not have the high-pressure core flooder on it so all those are connected to that. We can power up the fine motion control rod drives from the diesel generated bus on that particular division.

Then the mitigation if automated we can get recirc pump trips, six of them, when we get a trip on water Level 2, 4 on high reactor pressure or water Level 3. Really that should have been around 4 to trip off when we get to Level 3 and then the remaining 6 when we get to Level 2 or they will all trip off on the scram or alternate route assertion.

Feedwater runback, again it's part of the SRNM ATWS permissive waiting for 2 minutes before we go ahead and drop water level to decrease the amount of flow. And then automated boron injection as well.

CHAIR ABDEL-KHALIK: In the case of an ATWS if the standby liquid control system is initiated these pumps would be off?

MR. BEARD: That's correct. Remember we can't assume the pumps are there because they are not powered by safety-related AC power so we have to credit natural circulation for distributing the sodium pentaborate throughout the RPV. We are introducing it high up in one part of the arc and it's going to get pretty well mixed by the time it gets down to the pump deck.

Then as it goes down into the lower head it gets even further mixed. For the ABWR they did -- I don't remember the exact scale of the plexiglass model they built but they had a significant scale model where they actually looked at the mixing of the sodium pentaborate through all the various flowpaths and concluded we were getting very good mixing by the time it got down to the lower head and was ready to come up into the fuel assemblies themselves.

MS. ABDULLAHI: This is Zeyna Abdullahi, ACRS. I just wanted to ask you a question in comparison to the regular BWRs. There is a case where you want to make sure that your SLC design system pressures would not allow lifting during ATWS, lifting of your relief valve and it had to deal with your pressurization versus setpoint that you have, relief valve setpoint for the SLC system. Do you want me to reexplain?

MR. BEARD: Yes, please.

MS. ABDULLAHI: I just rushed through. Your SLC system has a certain pressure rating. Okay. That pressure rating is a certain amount 1,200 or 1,250. Then you have during ATWS when your pressure goes up you have a given amount of pressurization within your vessel. While the positive displacement pump can go ahead and inject any pressure, what will limit you is your relief valve on the system, on the SLC system.

MR. BEARD: Um-hum.

MS. ABDULLAHI: That will lift. Did you consider for that capacity? I don't know much about it. This is the first time I'm learning about ABWR but this is a lesson learned from the BWR.

MR. BEARD: The sizing of the safety valve on the SLC system -- I shouldn't say sizing. The setpoint of the SLC SRV safety valve is greater than the peak pressure that would be anticipated.

MS. ABDULLAHI: When it has the losses within your system?

MR. BEARD: Yes. Um-hum. Without lift unless we were dead-heading the system.

MS. ABDULLAHI: And then you don't put enough boron into the core and there is an information notice on it, I think, 2001.

MR. BEARD: Go back to the schematic. The other -- this is just kind of a detail. Earlier SLC system, standby electric control systems, used squib valves for the injection for the ABWR and we went back to them for the ESBWR. For the ABWR we went to motor operated valves, MOVs, for these two valves right here.

The reason for that was we wanted to have the ability to test the flow of the system using a demin water flow so with the squibs it kind of defeated the purpose of defining the squibs to do that and then put new squibs and new shear assemblies back in so we did change over to motor operated valves. If we didn't have the constraints on the ESBWR with management of electrical loads we might have stated that but we went back to the squib valves in the ESBWR.

Next. We covered that. I think I got to the end of my stuff and Dennis can take over. I am at the end of my stuff. Any questions before I turn it over to Dennis Henneke? I think we will probably have time at the end of Dennis' presentation to go back if you do have additional questions. Thank you for your interest and all your excellent questions.

MR. HENNEKE: My name is Dennis Henneke. Although I've been doing PRA for a little over 25 years I've been at GE about a year and a half and I was the lead on a STP/PRA update so I'm quite familiar with all of the details that we did for the departures and that type of analysis. Given the PRA is thousands and thousands of pages and detail there may be some areas that we may not have touched during the STP project. You may have questions and I'll have to get back to you on those. We'll see how we do with your questions.

I am also the chairman of the fire PRA writing group for ANS and anybody interested in that when the fire standard is issued so anybody who is saying that the fire standard is not issued, you heard it from me. It's been issued by ANSI and ANS. All those NFPA 805 plants can go ahead. Sorry for the diversion.

You have seen these next two slides in ESBWR presentation. I brought them in here because a lot of what I'm going to do is talk about during the design process and during a conceptual design of ABWR PRA insights were an obvious impact to the design. You saw what Alan gave you and I'll try and touch on the major areas that PRA asked for and received design changes in the original design. Then after that I'll talk about the changes with regard to STP.

Obviously in a new reactor PRA is a big part of it and you have to consider all aspects. Not just core damage but as you saw from the COPs design in the area of severe accidents and severe accident management and consider both internal and external events. We have examples of things that we changed on paper, and that is the easiest place to change it, for pretty much every type of event, internal, external, internal flooding, fire, seismic, and so on, that we added features or modified features related to the PRA. We mentioned a couple of those.

One of the requirements put upon us is

that we have a bounding assessment. I'll try to point out a couple areas where we still have considerable conservatism in the analysis that we do have so we expect the estimated core damage to eventually go down from where it's at. I'll point out where those conservatisms are. It provides us a safety case for a license and shows that we meet NRC's goals for risk in core damage or release.

Basically the PRA now goes into the DCD and FSAR. It's an integral part of the overall design process. Of course, that means anytime we make a small change in the PRA often times we get in the licensee space because we have to make a change to the FSAR. At STP we came to the first point where we had a change we wanted to put into the PRA that really had no affect on it. It had nothing to do with the change of design and it was called a departure. We had to make a departure just because we made a modeling change to the PRA and so the interesting impact of putting the PRA as an integral part to the overall design.

Of course, the PRA needs to be uploaded prior to fuel load and I'll emphasize that here. In STP we saw that even prior to fuel load there will be things that we can't meet in the standards because of the requirements of getting data and plant specific information with regard to training and so on. At this point in the design we are kind of guessing on some of the design features.

We are taking our best estimate on operator failure rates and so on. As you approach fuel load you will get information such as cable routing that you may not have had and fire loads for areas. That allows us to get a better risk assessment prior to fuel load. After fuel load again the risk assessment gets even better because you start to get information in regard to data, failure data, training programs, and more information on procedures and so on.

You have seen this slide but in ABWR there are a lot of examples of where this type of information has affected the design. This slide just shows that really as you get closer to fuel load you can effect a design even less and for operating plants we are talking about very small changes to the overall design without a significant expense but the changes in design have the greatest impact in risk so that is the best place to make the changes.

You can see from the overall core damage that we have taken a BWR design and enhanced the BWR-6 design and lowered the core damage by a factor of 10 to 100 with not a lot of new technology, with existing technology but using it smarter in most cases. You can, of course, later on make additional changes with regard to procedures and additional credit and that can reduce the overall risk but not as significant as you can in design.

Getting into the ABWR PRA I didn't want to spend a lot of time. We didn't make a lot of changes for the recent COLA for South Texas but basically I'll go through what we had in the original DCD and FSAR. We had up to a Level 3, relates to the public and dose assessment. We used representative plants from different regions to make sure that the analysis we did for acceptable dose, off-site dose, was bounding for pretty much every site in the U.S. We did that Level 3 assessment for internal events only, at-power internal events only.

For South Texas we did update that. That was a crack analysis for all three. We updated that with a max analysis for South Texas specific to show that the original DCT was bounding on Level 3 and it was. The South Texas site is bounded by the original DCT by a sufficient margin. We did a pretty good job of bounding the analysis for the original DCD.

We did all the internal and external events. Some of the external events were more screening such as the fire was a 5 analysis with some detailed core damage estimates, the seismic margins analysis rather than seismic PRA. We looked at all the internal/external events. We went to full power and shutdown. We had two appendices in the DCD on shutdown analysis including reliability of decay heat removal and then assessment of the shutdown, defense-in-depth and core damage for various plant operational states of shutdown.

We did look at seismic margins and it has had a number of detailed entries for seismic margins which should allow it to be eventually developed into a seismic PRA. It showed very good results. I'll get to that in a little bit more detail later but basically we have a high confidence that you will be above .6g prior to affecting any sequence of entries.

The major sequences that we were looking at, as you would imagine, the first most significant would be that of a station blackout followed by loss of AC independent water addition, fire water addition followed by things that have much higher seismic fragility going up above 1g for some accident sequences. All that detail is in our DCD and really none of that was affected by any of the STP analysis.

We did use generic data and generally it was conservative if you look at the most recent NRC data released earlier this year, I believe, up through 2005 data. Many of the basic events are up to an order of magnitude conservative in what we use. initiating events, of course, were historical and many of those were conservative with the reactor trip turbine being maybe 30 or 40 percent conservative or so but the LOCA events that we used, again, it's a 15-year-old PRA and 15 years ago we had a fairly conservative LOCA frequencies. The most recent NRC data would estimate an operating plant to have an order of magnitude of more or lower on LOCA frequencies that are used. What's in there now for STP is the conservative LOCA frequencies.

We did quite a bit of uncertainty and sensitivity analysis and that feeds into a lot of the various programs. We looked at modeling uncertainty and so on that did feed in to like the RAP program which I'll talk about on my last slide and a number of other areas that we looked at. So --

MEMBER BONACA: One second. The PRAs are 15 years old?

MR. HENNEKE: Generally speaking, yes.

About 15 years. We had some during the approval process and review by the NRC. We did have some questions. There were some RAI responses and there was a couple of questions where we did some sensitivity updates since that time. Generally speaking the original PRA was performed about 15 years ago.

MEMBER BONACA: Are you making any effort to update the PRA? You have a lot of conservatives but that may mask some of the outcomes of the PRA just because you seem to have a heavy conservative in certain areas.

MR. HENNEKE: Yeah. If you get back to my experience of trying to add a common cause event, the history of that is that there was an RAI by the NRC during the review process and we realized it was service water cooling. Common cause was not well addressed so we looked at it in a sensitivity case and actually increased the core damage.

We said in the DCD next time we update we'll include this common cause. We went to include the common cause and just that one basic event was considered a departure. Anything we affected at this point in the model to update to today's technology would be considered a departure. We were at this point asked not to do that.

MEMBER CORRADINI: Say that again? I think I understand what you just said. You tried to improve it and the moment you try to improve it you invalidate this part of the DCD. Have I got that right?

MR. HENNEKE: That's correct. It's opens up to legal rereview of an approved PRA. As long as we use the approved methodology and approved models, then it is an approved DCD.

MEMBER ARMIJO: It's static.

MR. HENNEKE: It's static at this point but South Texas has committed and I think every plant will commit to updating prior to fuel load to something that meets the standard.

MEMBER CORRADINI: But that is their COL, not to the DCD.

MR. HENNEKE: That's correct.

MEMBER BONACA: The Japanese plants as you perform PRAs there is a level of decay?

MR. HENNEKE: The most recent is, the Lungmen, and that was updated to this summer and the overall risk results are very comparable to what we saw.

MEMBER BONACA: That's what I like to

hear. You didn't find that you had some skewing that was unexpected. You found some conformation from the updates.

MR. HENNEKE: The overall risk profile for the Lungmen is very similar to what you'll see on the next slide.

MEMBER BONACA: Thank you.

MR. DUBE: Don Dube, NRO, Division of Safety Systems and Risk Assessment. In direct answer to your question, by Part 52 before fuel load the applicant, or the COL holder, which would be South Texas, are required actually by the rule to update the PRA to meet standards that were in existence one year before fuel load and the standards would be the ASME standards which requires to the extent possible best available models and/or acceptable models and failure data.

That would probably be the local time I would say. It probably doesn't make sense between now and then to go through the effort, as Dennis said, to do this just for the sake of demonstrating lower risk when they meet -- you know, the NRC safety code is by large margins already.

MEMBER BONACA: I wasn't -- that's good. I am feeling comfortable that they have done updates recently and found not significant depresses.

MR. HENNEKE: The Taiwanese plant in Lungmen.

MEMBER BONACA: You showed us this curve how design data and procedures are affected with time. If you have the data that is not right anymore or procedures which are not valid anymore, you must have some design issues that are resolved in the design stage.

MR. HENNEKE: I don't think we have seen anything in the PRA that would be incorrect but in today's PRA that level of detail is quite a bit higher than it would have been 15 years ago with common cause and operator dependencies and so on. Operator dependencies would not be a big deal for the ABWR but the common cause would. I think when you expand that model you start to see a slight affect in that regard.

MEMBER BONACA: All right. Thank you.

MR. HENNEKE: Okay. So in the design process of various stages PRA was involved in that discussion and PRA has been part of the GE and GE Hitachi engineering since the beginning of the design. We had input to things like the elimination of the recirculation piping to, as Alan discussed, remove a large LOCA possibility to uncover the core.

In the PRA I mention that we don't actually credit the lower LOCA frequency but I expect once a detailed piping analysis to get a large LOCA frequency you will start to see quite a bit lower large LOCA frequency for an ABWR plant than you would for general BWR. Eventually you will probably see South Texas come up with something similar to that.

We talked about during the slide the three-train design of the ECCS with high pressure and low pressure, ADS all three trains and PRA. PRA results from the existing BWR fleet were essentially in trying to create that overall design and actually lower ECCS flow with a much more reliable system.

Credit for the AC independent water addition was added in places. In fact, it was eventually decided not to add that into the internal Level 1. It was only credited for Level 2 analysis. The most important area where it would have fit into the accident sequence would have been during station blackout where we already had operator actions associated with the line in the CTG.

If we had operator dependencies there without procedural guidance, it would be hard to tell how much additional risk reduction we would get in a Level 1 with regard to that. It is in the seismic analysis. In the seismic entries it is in the Level 2 analysis for water addition post-core damage for containment protection.

Design of the COPs system and later on I have a -- down below talk about accident mitigation. I mentioned that to fill the bottom of the reactor vessel for COPs operation, continuing operation. The PRA had input to that. Combustion turbine use and design.

Again, with South Texas when they redesigned their medium voltage alignment when PRA was in the middle of that discussion to make sure that it was fairly simple, single switches to backup a diesel generator with the CTG and that was the design backup that we had in the PRA that showed a fairly low risk of station blackout and loss of power crediting the CTG.

Use of the lower drywell flooder, talked about that. PRA was involved in that. Seismic LOP guidelines. There were some seismic sequences that we looked at where there would be system operation but the MOVs associated with those systems the transformers may have a lower seismic capability than the actual emergency busses so we have some general guidelines so when the plant procedure developed to make sure that manual operation of critical MOVs are considered in the plant's specific procedures. That is part of our recommendation in the DCD.

Aux. shutdown panel operation lowered the fire risk considerably. Both the LOCA operation of the RCIC for controller evacuation as well as improved capability in the ADS operation showed considerable risk reduction for containment evacuation. Containment evacuation still is the number one fire accident sequence but it lowered down considerably to get it to --

CHAIR ABDEL-KHALIK: How far is the remote shutdown panel from the controller?

MR. HENNEKE: Most shutdown panels are in the reactor building within a minute.

CHAIR ABDEL-KHALIK: Okay. Thank you.

MR. HENNEKE: Alan talked about some of the flood controls for the control building. That was one of the larger floods associated with that and service water piping. There was additional level instrumentation of the control building that would automatically isolate that piping and there were some other controls that were added and associated with internal flood.

You can see there is just a handful of

things that we were involved in early on that came up during South Texas that resulted in an overall low risk to the plant. Seismic, flooding, fire, all the accident sequences were associated with this design approval.

This is our rough estimate of core damage. At this point it's actually somewhere closer to 2.5 10 to the -7 is our best guesstimate of risk at this point. Lungmen estimated around 3 to the -7 right now but, again, using conservative initiating event frequencies.

The original DCD had 1.6 10 to the -7 so the one additional thing that we had actually reported in the DCD as a sensitivity case or the common cause where we actually said if we were going to include common cause the risk would have gone up. That is actually where we did the starting point for this analysis.

MEMBER CORRADINI: So this is not -- I'm sorry. Go ahead.

MEMBER BONACA: So power internal events. Right?

MR. HENNEKE: Yes. Shutdown fire but internal flooding so just half power.

MEMBER CORRADINI: I want to understand

how you explain that. This is not the PRA from '92. This is the PRA from '92 with an estimate of common cause effects and the delta of common cause failures on top of that. Did I understand that correctly?

MR. HENNEKE: Taking into account the departures for South Texas and generic departures associated with ABWR and the LTRs.

MEMBER CORRADINI: And the departure from South Texas is what you are alluding to the cooling?

MR. HENNEKE: I have those on the next slide. Station blackout used to be a much larger part of the pie, almost 50 percent. That actually went down quite a bit because of two things. One is an update of the loss of power recovery and off-site power frequency based on more updated data. In loss of off-site power the frequency has down the last 15 years which is good news, but the long-term recovery, fail to recover of greater need.

Ours has actually gone up by about 40 percent. The hurricane data has gone into play so we know that although the overall risk of station blackout and loss of off-site power has come down, the risk associated with events greater than eight hours has actually gone up overall. It's part of removing or masking we were talking about earlier that we want to get everything in correct proportion that is in there now.

The pie chart when I look at it shows me a good balance with regard to defense-in-depth. The PRA is a defense-in-depth model and the mitigative systems associated with detecting the core should be proportional to the initiating event frequency. If you've got that well in balance, then you don't have a pie chart at something with 50 percent or greater of the pie chart. That's what I'm showing here.

MEMBER BONACA: So reactor shutdown are these events during refueling?

MR. HENNEKE: No, this is just a reactor trip or manual reactor trip from power with everything available. No MSIV closures, no feedwater loss. We use about one trip a year and that number is probably now for most reactors down below .5 or .6, just a regular reactor.

MEMBER CORRADINI: And then associated single failures for human events that take you to a CDF?

MR. HENNEKE: Right. It's the conditional loss of feedwater at about .05 and then failure of all your ejection systems.

MEMBER CORRADINI: If you were to put in

seismic, or that will only be done at the COL stage for that particular site and that's what they will add in?

MR. HENNEKE: It shouldn't be that difficult.

CHAIR ABDEL-KHALIK: Would that overwhelm this number, though?

MR. HENNEKE: I'm not sure. It shouldn't for South Texas but it depends on the site, I guess. It shouldn't overwhelm it because you are talking about somewhere in the .6 to .7g range of getting to where you have significant probability of core damage. That number should be in this range. I haven't looked at it specifically for South Texas but I expect it to be lower than this number.

CHAIR ABDEL-KHALIK: Thank you.

MR. HENNEKE: PRA was involved in a review of all the departures which Joe Savage will talk about those departures including the LTRs. Most of those were generic or many of those were generic. Some of them were South Texas specific. The major ones here, some of these are multiple departures. We've combined them into groups here.

The instrumentation changes associated with use of the new digital INC. There is a slight change in architecture. We did not credit the lower likelihood of a trip due to this architecture so that did not go into our model but we did estimate a slightly higher unreliability for that and that is associated with an automatic bypass. For one channel of the 204 logic for ECCS determined to be inaccurate it would automatically bypass that and go to 203 logic. That function is not in there and it resulted in a very slight increase in the amount of risk.

Alan showed the power distribution. The original had a design of single medium voltage that went from dual voltage and it resulted in an overall risk reduction. RCIC pump design, again, a small risk reduction basically due to the removal of the external lube oil and external cooling.

MEMBER CORRADINI: I guess I want to understand the percentage of change. Is this a one-off analysis? If I had the old power distribution I would get some number. If I have new power distribution I would get 1.5 percent lower number overall? Is that how I understand this percentage?

MR. HENNEKE: If you calculated it without the others involved you would get a different number but if you calculate it with everything in and with everything out this is the difference you would get.

Yeah, individually one versus the other.

MEMBER CORRADINI: Okay.

MR. HENNEKE: The RCIC pump design, we would actually expect the new RCIC pump to be more reliable than the old? I think everybody expects that but we did not have sufficient data to bring that into the model. This is simply the removal of the external lube oil. We expect that number to go down even further once we get reliability data for these pumps.

The addition of the cooling towers actually versus the spray pond we put that into the model. Because the cooling towers require fans we added those fan failure models in there including common cause of the fans and so on. That was an overall 6.4 percent increase in the risk.

MEMBER CORRADINI: So fans are more unreliable than pumps.

MR. HENNEKE: The pump design for a spray pond you can either go from the pump into a spray pond and recirculate back or you go into the cooling tower and then it has to have a fan for circulation. The fans are an additional component over and above the spray pond and that additional component will be a risk increase. You just can't --

MEMBER SIEBER: Do the numbers go in when you provide an alternate link? Why does it go up?

MR. HENNEKE: Because you have additional components that may fail to function.

MEMBER SIEBER: But you can still use the spray pond. Right?

MR. HENNEKE: There is no spray pond. It's in lieu of the spray pond.

MEMBER CORRADINI: So this is forced?

MR. HENNEKE: Forced for the cooling towers. It was based on an assumption in the DCD. It wasn't something committed in the DCD and we just changed the assumption of what would be --

MEMBER CORRADINI: Okay. Thank you.

MR. HENNEKE: The new loss of off-site power numbers in there I mentioned earlier actually result in about a 12 percent overall decrease. Overall these changes resulted in about a 9 percent reduction in CDF for the departures as we analyzed it. The difference you see here again why we are reporting a slightly higher number over the original one was because of common cause. We had actually reported in Appendix D of the DCD as a sensitivity case and in that sensitivity case we said we would include it next time and that's why it's here. Anymore questions on this?

Last slide. Again, we are talking about how the PRA has an input. Obviously for new reactors the PRA will have a large input to many of the programs. Where existing reactors have input now such as maintenance rule and so on as well as into the area of important operator actions, control room design, all that kind of thing. One of the more important areas, the reliability assurance program formerly in the process.

We updated that for South Texas and obviously the risk changes and what's important and what's not important changes. The change we made you saw before. Nothing came out of the reliability assurance program but things did get added in as associated with the changes.

The reliability assurance program includes, again, from every aspect of the risk assessment. Whatever was important for fire went into that whether it be a maintenance or testing program requirement from the PRA.

One item of note was that we added for STP the external flooding, important issues with regard to external flooding. There were two of those and one was associated with the reservoir to make sure that they have a program to detect any sort of early break in the reservoir. The other one was associated with the control room door. The control room is below grade.

External flood the control room door would be open and would go into the control room and there could be a direct core damage if it was allowed to continue. So the maintenance of that control room door, the closure of the control room door greatly affected the overall risk results so that went into the recommendations coming out of the STP update.

That's all I have.

MEMBER SIEBER: Can I ask a question about your presentation? How far along in the design of the instrument systems is General Electric? Do they have a system in mind with communications modes and software types or is it more generic?

MR. SAVAGE: This is Joe Savage. They have a pretty good description in FSAR Chapter 7. We've got an architecture that is described there. As far as getting into selecting hardware, etc., we are looking to be very consistent with Lungmen.

MEMBER SIEBER: How consistent are you with the Japanese plant?

MR. SAVAGE: The Lungmen plant has several advantages over K6 and K7. I don't remember those specifically but it had to do primarily with outdated equipment, outdated hardware that was used in K6 and K7.

MEMBER SIEBER: The Japanese use a single communication system that separate safety related from non-safety related functions but everything on the communication system can be either safety or nonsafety or mixed. Did your PRA study of instrumentation go far enough to decipher whether that is more risky or less risky and what is the experience since Japanese plants have been running?

MR. HENNEKE: The PRA looked and a detail of the PRA included the architecture and an estimate based on the design details that we had with regard to their overall reliability. We didn't see -- from the original DCD is what I can tell you. I'm not sure if that is the Japanese design for K6 and K7 but I believe it was.

MR. SAVAGE: Yes, K6 and K7.

MR. HENNEKE: To the Lungmen design, which is basically what we'll have there with a slightly updated Lungmen design, we saw a slight increase in the overall risk because, again, this bypass function, which is in the original volume, is not in the Lungmen.

MEMBER SIEBER: That is not necessarily due to the communication protocol.

MR. HENNEKE: That's correct.

MEMBER SIEBER: Did you take into account cybersecurity issues?

MR. HENNEKE: No.

MEMBER SIEBER: How did the instrumentation system deal with 3D, diversity and defense-in-depth? For example, do you have a backup separated analog system that will trip the plant for the important functions along with a digitized set of protective functions?

MR. HENNEKE: We do have that. Do you have any more information on that?

MR. BEARD: What I will describe is what was certified. Part of my hesitancy to get in this area, as Joe described, we are still in commercial negotiations as to who will have final design responsibility for some of the stuff. The certified design to address the common cause failure issue we have committed to have hardwired initiation of reactor scram, MSIV closure, and a high-pressure core flooder pump initiation.

At that point we said we would evacuate or, at least, send enough staff from the main control room to the remote shutdown panels and the way the remote shutdown panels were initially was they were in the system downstream with the digital decisions or out on the hardwired portions. At that point you could actually come in and disrupt the input coming from the digital systems and go to a hardwired response.

MEMBER SIEBER: So that is basically your approach to reducing common cause failures. On the other hand, you did not say that you would not duplicate brands or types of equipment or algorithms or anything else. For example, you have four protection channels that use some algorithm. Do you have diversity in the algorithm that you use or do you use the same one and take the risk of common cause failure?

MR. BEARD: Just like with the ESBWR we are using the same algorithm within the four divisions but we did have the separation of PRS and ESF and the fail safe versus fail-as-is design along with the separation of the things like feedwater control and steam bypass pressure control using your own dedicated control systems.

MEMBER SIEBER: In the appropriate functionality of the control system is the timing of the control system response to the analytical time necessary? Was that taken into account? For example, take a typical transducer. If you want to trip on high pressure a transducer has a certain response -- two seconds to get up to 90 percent before you actually get to trip. Is that taken into account?

MR. BEARD: Within the safety analysis, yes. The instrument response time is factored into the overall performance of the system

MEMBER SIEBER: Thank you.

CHAIR ABDEL-KHALIK: Questions? Is this a good time to take a five-minute break? Okay.

(Whereupon, at 4:00 p.m. off the record until 4:07 p.m.)

CHAIR ABDEL-KHALIK: We're back.

MR. SAVAGE: I'm Joe Savage, ABWR licensing manager for GE. What I would like to do is give you all an overview like Mark introduced earlier what our thoughts as the holder of the docket for the certified design and what are the plans for assisting our customer STP 3 and 4 with getting their departures incorporated into their license and then what are our thoughts and plans for benefits for a revision to the certified design.

I just want to make sure that everybody

walks away from all their questions answered. What I am going to do to begin with is to start through some of the departures and talk about some of the wheres and whys. If you all got questions, I'll be glad to answer those.

As Maitri mentioned earlier, SRVs have always been a problem in the industry so we went to look at a new setpoint methodology that we could utilize with the latest technology so that we could improve the reliability, etc., and so what we wrote was a departure from the methodology that was used to determine our SRV setpoints back in the early '90s.

We've got a lot of operating experience since then, things that have been incorporated through other licensee's work with the BWR Owners' Group so that we make sure we use the latest SRV setpoint methodology for STP which is different than what is described in the DCD.

On ESF and RPS control systems setpoint logic changes, there was an area that we saw that we could make a number of --

CHAIR ABDEL-KHALIK: Back to the SRV, are there new SRV designs that are sort of much more reliable?

MR. SAVAGE: Yes, sir. We think there is

a number of new designs that we are looking at in Japan and in Europe and we believe that like the numbers that would be associated with a PRA, they can be improved not only with improved SRV designs but also some other new design features that we can incorporate in future Tier 2 changes if we see that there is a benefit there.

MEMBER BONACA: You are talking about the methodology, setpoint methodology. How would that improve the performance of the SRVs?

MR. SAVAGE: Well, what we are looking at here is the fact that you can do your calculations on your simmer margin. The simmer is that little area when it's just barely wanting to open, etc.

MEMBER BONACA: Okay.

MR. SAVAGE: The next departure I want to talk about is RPS control system setpoint and logic changes. We've got a miscellaneous collection of things that we have learned from operating experience review in the U.S. as well as Japan.

One of these changes was the turbine first-stage pressure trip function and the fact that you had four little mechanical trip relays that had over time proved problems for industry including the fact that the mounting system was a problem, etc.

Rather than looking at using those same pressure sensors, we looked at what would be a more accurate way to understand when we need that trip function and what would be a good replacement for first-stage pressure. We found that neutron monitoring logic gave us a lot more reliable way to install a new trip setpoint to the place that turbine first-stage pressure.

As far as deleting MSIV closure on Hi Rad, that is an LTR that has existed. There has been a number of spurious trips throughout the industry based on that. There is already a BWR Owners' Group LTR that has been submitted and approved.

We talked about during Alan's discussion the third train of RHR being tied to the fuel pool cooling system and really we are just looking at increasing the outage maintenance flexibility, reliability, and the single failure criteria for cooling the spent fuel pool. That is pretty straightforward.

Feedwater line break mitigation was a departure that we felt like we wanted to make sure we could follow up on our no operator action within the first 30 minutes of a transient of ABWR. Right now the way the safety-related trip is set up to ensure no overfilling or overpressurization, it would require operator action.

The departure is that we added breakers and logic, all safety related, to trip the condensate pumps and reduce feedwater flow from that feedwater line break. Therefore, the operator doesn't have to take action to mitigate that overpressurization of the reactor vessel with feedwater flow.

The RCIC turbine we've talked about that a good bit. It's simpler, eliminates hardware. Probably not worth mentioning much more. Departures for the leading class 1E undervoltage chop tests/breaker coordination. Within the Tier 1 ITAAC there is specific coverage for this area with the pre-opt test and start-up test requirements.

The fact that we would rather do shop tests instead of the in situ testing is really going to be covered by our ITAAC. We did look at our Chapter 15 analyses to make sure there is no anything that is going to be impacted. We looked at Chapter 16 tech specs making sure that there shouldn't be anything. What it really boiled down to is breaker coordination under 120 volts. It's very difficult to get the sequence correctly and that is what we felt like we would rather commit to in ITAAC rather than have it in the DCD.

That needs to be an area that the way the DCD described it it was just a questionable way of testing versus what we had already recorded. We just wanted to revise our ITAAC there in Tier 1 to make sure that we got that incorporated on a start-up test plan to do the chop test and FAT test, factory acceptance test.

The departure on the additional division of I&C power. This is another class 1E I&C power supply that was required to support the fully developed safety related logics so we added a fourth regulating transformer. I know Alan didn't go into that level of detail but by adding that fourth regulating transformer and taking this departure we improved PRA numbers. We also improved the dependability of the electrical system.

The leading hydrogen recombiners, I believe everyone is familiar with why that was done. Control system architecture and technology. That is just simply evolving technology. What we found was when we are designing Lungmen and working with STP on where we may want to go and, of course, we've got several choices there to make.

We just need to make sure we use available systems that are going to be supported throughout the future. We recently found out that like the plant that is now being built in Germany that is very similar to the EPR that is being built in Finland will be the last plant for that particular set of I&C components and software will be supplied and the vendor said they won't support it any longer after that. We want to make sure we don't run into that and we think through that pretty far ahead.

MEMBER SIEBER: Do you intend to buy the software from another company or General Electric engineer is going to design the software?

MR. SAVAGE: I don't know that I can answer that question right now.

MEMBER SIEBER: Because the decision hasn't been made?

MR. SAVAGE: Yes, sir. STP site parameters, this was a departure that was somewhat unusual as far as humidity being outside the prior assumptions that came out of the URD. What was apparent was that we had a site parameter that we needed a departure from because of the main coolant reservoir at STP. The main coolant reservoir is a large downed pond. It's about the size of Lake Okachobee, or it looks that way to me.

You can see it from space from a long ways off but it's a non-seismic category one dam and it's all above grade. Because of that we had to make physical changes in water tight flood doors on the reactor building and on the control building. It's pretty evident why that site parameter had to be a departure.

The departures for Tier 2 Reg Guides and codes and standards updates you've got a couple of tables in the DCD, one that addresses NRC Reg Guides, one that addresses the latest codes and standards. We wanted to do the best we could so as an example for physical independence of electrical systems Reg Guide 1.75 we committed to Rev 3 which is February of '05.

Another example are the IEEE standards 384 and 603. We committed to the latest revision that is currently endorsed by the NRC. Those were the types of the Reg Guides and codes and standards that we took into account. Also al later version of ASME code and a later version of American Concrete Institute so that we make sure that we've got the latest earthquake data and related reservations that are referenced by the ACI.

Other departures for STP 3 and 4 it really comes out of what I have discussed previously.

Designed departures that are Tier 2 that require tech spec changes like the RCIC pump. You no longer have a barometric condenser that you have to monitor. The new I&C system touches 13 different laces in tech specs that have to be departures.

Any change to tech specs is considered a departure under Part 52. If you change a i or dot a t -- dot an i or cross a t, then that is definitely a departure. As far as changes of intent to tech specs we had eight places such as Standard Departure 16.5.1 that talks about unit responsibility.

Well, over the last several years through improved tech specs all the plants and all the BWRs have used the same nomenclature for their shift supervision. I'm talking about when you needed an SRO in the control room, when you didn't, etc., that was a typical intent changed to these tech specs which ended up being a departure.

Also, one of the changes of intent to tech specs that isn't one of intent was to properly define bases control and this is something again that has been done through the last 10 or 15 years on BWR tech specs but it wasn't done on the version that was submitted by GE that is incorporated in the design cert.

Then as far as editorial changes based on advice from legal, we made sure we annotated every editorial change because there has been a lot of consistency work among the utilities so that the operators see the same type of language no matter which BWR they work at whenever they pick up a tech spec.

As far as form and format and improving the consistency of the language, those were administrative or editorial type tech spec changes that we documented its departures. The one thing of note is that in talking with the South Texas project they are very interested in working with us to create fully improved tech specs.

Work in all the tech specs that are applicable to the ABWR, etc., and make sure that we get that into our design basis and our tech specs that we will be using going forward.

CHAIR ABDEL-KHALIK: As part of the basis control that you were talking about, are you committed to giving them essentially copies of the design basis calculations for them to maintain?

MR. SAVAGE: We are committed to work with them on how we control bases within the tech specs and our cals that are behind those, yes.

CHAIR ABDEL-KHALIK: But they are not going to have copies of those?

MR. SAVAGE: No, sir. We'll maintain design control. We will work with them.

CHAIR ABDEL-KHALIK: Okay. Thank you.

MEMBER MAYNARD: There are bases in the tech specs that are part of the tech specs and they will have that.

CHAIR ABDEL-KHALIK: The calculations behind some of those.

MR. SAVAGE: Okay. So let me just review with you the concept that there is not so many departures as maybe the numbers indicate. We have already gone through the 12 Tier 1 and Tier 2* departures and what they incorporate and sort of a little bit behind the whys of this. Those touch a lot of other areas in the FSAR such as a new RCIC Wier pump is going to have a new electrical control system, etc.

When you make those other changes that is a departure also although it is a Tier 2 departure under the 50.59-like process. The point being is that we've screened all of our departures per the Part 52 rules. We actually developed a 50.59-like process that was actually a little more extensive on the South

Texas project's 59.59 manual, modified that on how are we going to evaluate all of these Tier 2 departures most of the Tier 2 departures being fallout from Tier 1 departures.

Although I do want to point out some that were Tier 2 stand-alone departures such as the ultimate heat sink. That is, of course, a site decision. The dual units, the fact that with the DCD you have one reactor building, one turbine building, one radwaste building. STP and building 2 units should have a common radwaste building. That makes sense.

It's a good economic choice. We'll have tunnels between and that's a departure. Some of the design departures are based on experienced review and regulatory changes such as updating our suction strainers, looking at how we locate certain equipment such as Alan talked about. We are going to put the diesel generators actually inside the building.

That was not done -- that was done during the DCD but what we wanted to do was actually have some of the controls moved to the reactor building that were originally in the turbine building. It is minor things like that, equipment location. Another thing that we saw that we really wanted to change for

DCD or departures for STP 3 and 4 was radwaste process. The design certification document talks more in terms of systems and processes that are used in Japan and Lungmen.

What we decided to do and what the departure is for STP 3 and 4 is basically adopt or is exactly adopt the ESBWR radwaste systems in building because that is GE's latest best effort. It will use our latest techniques on shielding, on dose calcs, on analysis on how to configure the equipment, the fact that we don't be using centrifuges.

If you read the DCD description of the radwaste processing system you will see there is a lot of equipment in there that plant managers at BWRs decided they didn't need or they didn't want in their radwaste building. We wanted to take that out.

MEMBER BONACA: I would imagine that STP is asking for 60 years operation of this plant. Right?

MR. SAVAGE: Right now they licensed it -- they have told me they want to apply for a 40-year license.

MEMBER BONACA: 40-year license?

MR. SAVAGE: Yes, sir.

MEMBER SHACK: Even though the DCD is for

60?

MEMBER MAYNARD: I didn't think you could apply for a 60-year. I think you can only do a 40 and then apply for a 20-year extension.

MR. GARTMAN: I believe that is correct.

MEMBER BONACA: So they have to go through the normal process. I thought they were talking about -- oh, okay.

MEMBER SIEBER: There's a couple more plants for you to review.

MEMBER MAYNARD: I think all the new plants want a design capable of supporting a 60-year life.

MR. SAVAGE: That's right. We are designing for 60-year life.

MEMBER MAYNARD: But I don't think they can apply for a 60-year license.

MEMBER BONACA: I am saying that you would want to incorporate already some of the basic requirements that you have to address for an additional 20 years just because it comes naturally. I mean, the plant is designed for 60 years so, therefore, you are not restricted in doing that.

MR. SAVAGE: Even though we have like total of 118 Tier 2 departures, 55 of them are because of the changes in digital I&C and what you have to change in FSAR Chapter 7. About 30 some odd of them are because of a change in the radwaste building, etc. The number may sound big, and it is big. we count each and every change to the design cert but it is mainly because of the major conceptual design changes, the experience review, lessons learned, and those type things.

The license topical reports. Most of these are being driven by COL action items where there was additional information requested to support the DCD. We wanted to close as many of those as we could. Some topical reports such as the RCIC pump are addressing a design change, a departure, and we wanted to go ahead and get that concept because we had a pretty fully-developed mechanical concept and the Wier pump information was available.

We felt like we could go ahead and have the staff get an early review there. Items like the plant procedures development plan, startup admin manual. All of those things are pretty much straight COL action items that we are willing to get closed and, hence, we have submitted those LTRs to you all.

Of course, the cover letter explains to you this is to close certain COL action items or this is to install a new RCIC pump that improves the plant.

MEMBER ARMIJO: Why is the reactor material surveillance program changed? It seems like it's pretty cut and dried sort of stuff.

MR. SAVAGE: It is pretty cut and dried. We've got some configuration and some specimen changes, the size and the way the coupons were cut and the way they were hung, etc. I forget but one of the plants had some problem retrieving mirrors so we were implementing lessons learned there.

Just in summary, let me just say that the ABWR design improves on what we know about U.S. operating designs. We have looked a lot at the Japanese fleet. We have spent a lot of time talking to K6 and K7. We spent a lot of time with Lungmen. We have actually been talking about how to improve operations training looking at things that the Japanese have done in their simulator and within their EOPs and our planning of how to do our EOPs.

We want to make sure that not only have we taken advantage of the U.S. operating experience but we have also taken advantage of what the foreign plants are that are ABWR what they have learned in the last 18 years of operation.

Any other questions?

MEMBER SIEBER: I have a couple.

MR. SAVAGE: Yes, sir.

MEMBER SIEBER: The 1997 ABWR DCD, is that modeled after the previous plant that GE has built? Is that the K6 and K7?

MR. SAVAGE: K6 and K7. Yes, sir.

MEMBER SIEBER: But not Lungmen?

MR. SAVAGE: Not Lungmen.

MEMBER SIEBER: And these topicals is that deviation from K6 and K7 or deviations from the DCD which may or may not match K6 and K7?

MR. SAVAGE: They are deviations from the DCD that may or may not match K6 and K7.

MEMBER SIEBER: So we can't go back and look at K6 and K7 for where your analysis came from?

MR. SAVAGE: No, sir. We haven't intended to. Mainly what we've looked at is operating experience. No different than the way the INPO program works in the U.S. as far as what have you all learned during your operating time. We reviewed that to decide is there anything that we could and should change about Lungmen and/or any USA BWR. That is all I'm saying we looked at. We did not look at it as a design basis.

MEMBER SIEBER: I'm trying to lead you

into saying something. K6 and K7 were designed to codes and standards. The Japanese have codes and standards which I think look pretty much like ours. Their nuclear regulatory codes and standards laws look something like ours, too. The plant would not necessarily meet U.S. regulations in every respect.

MR. SAVAGE: We know it would not.

MEMBER SIEBER: Did you sit down with the K6 and K7 designs to figure out what it is you had to change?

MR. SAVAGE: Alan.

MR. BEARD: Yeah, I was going to say I want to dispel the notion that K6 and K7 is the absolute carbon copy for the DCD. It's not. it is fundamentally the basis for what was certified but there were significant departures from K6 and K7 versus what we certified in the DCD primarily in the areas of physical separation both mechanically and electrically as well as mitigation of smoke and fire.

MEMBER SIEBER: What I'm trying to get at is to learn more about how the Japanese design plants. I have some questions about instrumentation and communications networks versus the frontend and the backend and 3D concepts and cybersecurity. I don't want to get real detailed here because I don't think the purpose of this venue is that and you may not be able to answer real detailed questions.

What I am looking for is there a sufficient diversity between the Japanese plants and 1997 that we would not learn anything by looking at the Japanese designs and protocol particularly in instrumentation and control.

MR. SAVAGE: You are talking about --

MEMBER SIEBER: I'm looking at these plants that are operating. I don't know that they are building that many new plants right now.

MR. BEARD: If you were to look at K6 and K7 we know there has been very significant changes in technology in this area of instrumentation and control. that would not be a very good reference point. We certainly will update very substantially beyond that.

MEMBER SIEBER: My guess is based on earlier work as an I&C engineer for me and buying computers which go obsolete in six months with new techniques and what you would pay $2,000 you now pay $300 for, I would imagine that you wouldn't find any two plants unless they were built together on the same site that employ the same instrument architecture. That is probably correct. You haven't decided what you're going to do, who the vendors are going to be or what the architecture is going to be for AP600, right? Not AP600, ABWR. Is that correct?

MR. SAVAGE: Alan, you can confirm. Yes, sir. I believe that's correct.

MEMBER SIEBER: Okay. Thank you.

CHAIR ABDEL-KHALIK: All right. At this time I guess we'll -- thank you, gentlemen.

MR. TONNACI: I will pull up the remainder of my presentation. Okay. Well, it's good to be back up here. We'll wrap this up. Actually, much of my presentation I gave via the questions and answers from the first time I was here so there isn't too much left to cover. Unless there are questions, I'm going to zoom through the first couple slides and get to what we haven't touched on yet.

We talked about the DCD. We talked about the topicals, South Texas and how they all relate so I'm not going to go through that again unless there are more questions on that.

MEMBER ARMIJO: I'm going to have to ask a question. The last one, that arrow, it seems to go in the wrong direction. Once you've done all of the STP 3 and 4 COLAs and approved all of those documents, why isn't there a simple arrow to update at ABWR CDC

Rev 5?

MR. TONNACI: GE needs to come in and petition to update that. When they provide that request, then we will at that time whatever they want us to incorporate, probably all the topicals and many of the standard departures from South Texas, there will actually be arrows, you're right, going from the topicals and the COLA down to the DCD. I envision that is what we are doing.

MEMBER ARMIJO: If they made no changes, absolutely no changes from those topicals, all the work has been done?

MR. TONNACI: Most of the work has been done. There is very little.

MEMBER SIEBER: The slide we have in the pack is different than the slide you have on the screen.

MR. TONNACI: Oh, it is?

MEMBER SIEBER: Yeah. It's got an arrow --

MR. TONNACI: Oh, I see. I think you are probably right. That arrow should go the other way. My daughter helped me with the fanciness and I think I got carried away so thank you for that.

MR. GARTMAN: His daughter would have

gotten the arrow right.

MR. TONNACI: Probably so.

MEMBER CORRADINI: Just to make sure that I'm understanding, from the standpoint of the next step, you said the first time you were up here if the STP -- if South Texas COLA was approved based on the topical reports which are the departures with the DCD 4 that's it and you're done -- they're done?

MR. TONNACI: Yes.

MEMBER CORRADINI: And then somebody downstream could do one of two things. Could say, "I'm going to order a boodle of these from GE. Go do me a DCD, otherwise I'm not going to do it." Or, "I'll use STP 3 and 4 as their jumpoff point and say I'm going to do it just like STP 3 and 4."

MR. TONNACI: That's right. That would be the reference plant. STP 3 actually is the reference.

MEMBER SHACK: If you did that, that COL is not challengeable or is final for STP but for the next guy it wouldn't necessarily be final. Whereas if it was incorporated into a DCD it would be final so there is a difference between the two approaches.

MEMBER CORRADINI: But the difference is pretty minimal because I'm going to have a new site and I take the same plant and all the stuff, have to give new PRA, have to do a new site analysis.

MR. GARTMAN: I don't actually know that is correct. We would have to go back to Part 52 and maybe get Jerry. Except for the site specific items, these subsequent COLAs coming in I think could piggyback on STP since the topical reports were approved through the --

MEMBER SHACK: They could but the question is whether they are as final as the DCD. There is no question they can.

MR. GARTMAN: I think that's what I'm getting at, that they do have that finality.

MEMBER SHACK: It is final.

MR. GARTMAN: That would be worth -- that could be a takeaway for us to double check on. My understanding of how Part 52 was designed to work was that subsequent COLAs coming in could rely on the reference COLA for that finality

MR. TONNACI: I am unsure so why don't we get the answer and get it back to you.

MEMBER MAYNARD: But the reason that GE is not really applying for Rev 5 right now under the current law that would require rulemaking.

MR. TONNACI: Correct.

MEMBER MAYNARD: Now, there is proposed

rulemaking or the rules may change where that wouldn't necessarily result in a rule change in the future. Correct?

MR. TONNACI: They can make amendments. Jerry was here and passed me a note. They can amend DCD. Quite frankly I'm not sure what the mechanics are.

MEMBER CORRADINI: But the amendment process is what AP1000 learned. That's what we heard.

MEMBER SIEBER: That's under amendment.

MEMBER CORRADINI: I thought. That's a question. I shouldn't say it so -- that was my impression on whatever subcommittee we were at in November.

MEMBER SIEBER: But it was reviewed as a separate DCD not incorporating by reference.

CHAIR ABDEL-KHALIK: You can find out and get back to us.

MEMBER SHACK: It's not a problem we need to address at the moment.

MR. TONNACI: Okay.

MEMBER SIEBER: Ask George when he gets here.

MR. TONNACI: I think I touched on much of this about how we are going to approve the topical reports. We already had a process in NRR when there is a technical report coming in that many plants want to use. You go through the approval process for that topical when a plant comes in and applies to use it and we look at it for their site-specific conditions. As I said earlier, this is exactly what we are going to do for these topical reports.

Okay. A question that Maitri has asked me many times is what is the schedule. That is a little hard to pin down so I'll share with you what I can. Generally most of the topical reports are pretty far ahead of South Texas because they came in many months ahead of time but not all of them.

A couple of the last topical reports came in just a month before South Texas. Those last couple will pretty much follow along with the South Texas approval process. The ones that we can do ahead of time we will and the staff has already started reviewing those.

The schedule we would like to get them at least a batch to you late in the first quarter of 2008 but there are a lot of caveats on that that depend on staff support and GE support that we need for RAIs and so forth. Basically these are not part of a committed schedule that we have at this time for the topical reports. We will be following the South Texas which is the only thing we are committed to.

The STP COLA, the lead for that is actually George Wonder and on that day we'll be coming into ACRS where the topical reports will only come in if you ask for them. If you don't ask for them, you'll see them anyways or have to go through the questions through the South Texas review at that time.

The South Texas COLA currently --

MEMBER SHACK: Are these reviews ongoing for these topicals?

MR. TONNACI: Yes. We have started but we have not written any safety evaluations yet. We are still in the RAI process for all of them.

MEMBER SIEBER: There are about half that the RAIs have sent out that are answered. The other half of them I don't think I saw any RAI on the schedule. You're talking three months before you are able to assemble the SER for that topical.

MR. TONNACI: That's right.

MEMBER CORRADINI: I just wanted you to repeat what you said so I understand it properly. The chance for the ACRS to see these topicals could be as your SERs are developed or wait and they will have to come up anyway through the COLA.

MR. TONNACI: They won't come in per se. Actually, they will because their safety evaluations are put right into the COLAs so the answer is yes, they will come in through the COLA.

MEMBER SIEBER: You've got a disk for a topical report.

MEMBER CORRADINI: But it's not all of them is the way I understand it. It's some of them but not all.

MEMBER SIEBER: There are 13 here and I think that is how many --

MR. TONNACI: That is how many we have.

MEMBER SIEBER: -- General Electric is proposing to send in.

MR. TONNACI: That's right.

MEMBER SIEBER: What we haven't seen is the SERs or the RAIs or the answers. That's what we are waiting for.

MEMBER CORRADINI: Jack is right. I've got that, too. You wrote down in the previous viewgraph expect some other topical reports late in first quarter of 2008 so more will come. Yes?

MR. TONNACI: In the previous slide?

MEMBER CORRADINI: In the slide you have up. I'm sorry. I was ahead.

MEMBER SHACK: You don't expect more topical reports. You expect the SERs.

MR. TONNACI: I expect the SERs will be ready for your viewing.

MEMBER CORRADINI: I misread that. I'm sorry. I misread that.

MS. BANERJEE: This is Maitri Banerjee. I don't think we received all the topical reports yet. The last one was continued analysis but there were three more like radiation protection, design reliability, and preoperational test. Those are not received yet.

MR. TONNACI: I think we talked about those earlier. Those GE doesn't plan to send in at this time. That's all we have. That's all I have been made aware of at this point.

I want to just touch again on the STP COLA. They currently schedule two rounds of reviews by ACRS. One will be the safety evaluations with open items and then come back later when the open items are closed. There really isn't an official schedule for South Texas at this time.

We recently sent a letter and you may have seen or been aware of this that the South Texas application while it was good and had a lot of detail there were portions that didn't have sufficient depth for us to build a schedule. Because of that we docketed it but we have not committed to a schedule until we get the remainder of that information. Okay.

I was also asked to touch briefly on COL information items and how they are handled so I'll touch on those. COL information items are largely used or have been used for operational programs such as start-up testing and start-up manuals, those types of things. Reactor vessel vibration was another one.

MEMBER SIEBER: Radiation control?

MR. TONNACI: Yeah. There are hundreds of COL information items that are open. They are basically open items from when they approved the DCD that you couldn't close then. The idea was at that time the COL applicant would close them when he made his application to us. However, now we are realizing in some cases they have actually got to go buy equipment so they can't do it now either.

For example, start-up testing. You really can't write up your start-up testing program until you've got --

MEMBER CORRADINI: Until you know what you are going to test.

MR. TONNACI: That's right. You get into

some of these situations where you can't do it now either. GE has sent in topical reports that in some cases do completely address the COL items and they have done so. As a topical everybody will be able to use it. An example is reactor vessel vibration. We had a COL information item that says basically demonstrate that the vessel is not going to shake itself apart.

The technical report GE has written based on the Japanese plants they sent it into us as a topical and at this point once we go through the approval process that information on them can be closed in its entirety but there are others like start-up testing that you can write up how you are going to do it and what the administrative controls are going to be but you can't go any further than that until you've got the plant built so you can partially close some of these but not completely.

The Reg Guide 1.206 realized that was going to happen so they gave the applicant four options to deal with COL information items you can't close. They can say it's redundant to an ITACC. In some cases it may be. They can propose a new ITACC for these.

They can propose a license condition or

what South Texas has done in almost every case that I've seen is they can simply say describe it in a level of detail as much as they can right now and give us a date when they are going to do the rest of it which maybe six months before fuel load or whatever is appropriate.

They've got to have sufficient detail and justification now and we can go ahead and write our safety evaluation for that portion to say as long as they do this it will be closed out by the construction inspection organization at the appropriate point during construction and the safety evaluation will simply address the technical merits of what they have provided to us.

That's how COL information items work and that is actually the end of my presentation. Are there any other questions for me?

MEMBER MAYNARD: A quick one. We would review the topical reports that GE submitted but not the applicant at this point. The applicant may or may not be referencing?

MR. TONNACI: The applicant is referencing these topical reports.

MEMBER MAYNARD: So we would only be reviewing these one time, the ACRS.

MR. TONNACI: You would review them for sure, say, if I brought RCIC into the first quarter, you could review it then and we could answer whatever questions. We would write a safety evaluation. When that chapter, say Chapter 5 comes in as part of the COLA and you've got more questions, there is no finality to what we did six months or a year earlier so basically you don't have to look at it but if you have questions that have technical merit it is fair game.

MEMBER CORRADINI: Then I guess I will ask a question of the chair. Somehow we've got to figure out a plan of attack so we don't have to go through things twice.

CHAIR ABDEL-KHALIK: We just have to keep good records, I guess. When those things come back again if we don't have new questions, then --

MEMBER MAYNARD: It's it in a fairly short time that works. The problem if it's over an extended period of time you change memberships and that way we end up having to review the same thing twice.

MEMBER SIEBER: Let me ask you a question. The topical report does not represent an amendment to the DCD.

MR. TONNACI: Not at this time. That is

correct.

MEMBER SIEBER: If somebody wanted to build one of these plants he would cite the DCD. That's already approved, okay? You wouldn't have to submit additional information. Now you have written a topical report. For example, constant pressure power upgrade. Somebody says I have designed my plant to meet that requirement and here is how I meet them that are in that topical. Then you don't have to review the topical again. All you have to do is review conformance to the topical.

MR. TONNACI: You are exactly right.

MEMBER SIEBER: I think that is the way this will work, too.

MR. TONNACI: You've hit it right on the head. That's the way it works. When we get the COLA those chapters come through there's chunks of it that you don't have to look at but it doesn't mean you can't if something has come up.

CHAIR ABDEL-KHALIK: We will try to time the reviews of the topicals so that we wouldn't run into that problem.

MEMBER CORRADINI: Freeze the membership.

CHAIR ABDEL-KHALIK: Okay. Any other questions for Mark? Well, thank you.

I would like to open the floor now for members in attendance to see if there are any additional questions or comments that we can take away from today's presentation. Jack.

MEMBER SIEBER: The only thing I can say would be advice in getting ready for these meetings. In order to be able to deal with all these you actually have to read the topical reports. I would advise folks to do that if they haven't already done it. I presume since we've had that disk for a month and a half or two months that everybody has done it.

MEMBER CORRADINI: Don't put out a test on that.

MEMBER SIEBER: Well, I didn't do it until last week and I finished the last one this morning. I would just point out that is another step that has to be done offline.

CHAIR ABDEL-KHALIK: Sam.

MEMBER ARMIJO: I thought it was a good presentation. I'm glad the list of topicals is relatively short. Some of them are very straightforward. I think --

MEMBER SIEBER: Draining the pump is easy.

CHAIR ABDEL-KHALIK: Yeah, and the recombiner things pretty straightforward. Based on what I see it should go pretty smooth.

CHAIR ABDEL-KHALIK: Bill.

MEMBER SHACK: No particular comments.

CHAIR ABDEL-KHALIK: Mario.

MEMBER BONACA: Nothing, thanks.

MEMBER MAYNARD: I was in the same boat. The fact was I just reviewed my topicals and then I looked at the agenda and found out we're not going over those specific areas. I appreciate the presentation. I got a lot out of this since I was not part of the ACRS when we did the original design certification and I thought it was a very good overview of the design and very good information.

I think that we need to make sure we try to do this as efficiently as we can without having to review the same thing twice. Also from several of the topicals that I looked at I'm not sure that we need to look at all of these and look at all of them in very much detail. I think we need to be selective as to what we think we need to look at.

MEMBER SIEBER: We need a process. I agree with that. We need a process where we can review in advance of establishing a review schedule to decide whether we need to review it or not because just to have a meeting just for the fun of it is not my cup of tea.

CHAIR ABDEL-KHALIK: Maitri and I are working on that. We have the detailed schedule.

MEMBER SIEBER: My suggestion is that you assign these topicals to various members who have some expertise.

MEMBER CORRADINI: We have assignment sheets.

MEMBER MAYNARD: There is an assignment sheet.

MEMBER CORRADINI: Yes, we do. I've already gotten my assignments by the chair so that's why I'm asking all these questions.

MEMBER SIEBER: I don't have any assignments.

MEMBER SHACK: You would be amazed how easy it is to review a nonproprietary version of the vessel surveillance program.

MS. BANERJEE: That one I need to send out. I think we received the proprietary version.

MEMBER SHACK: We did before and you told me to destroy it.

MEMBER SIEBER: You are supposed to make a copy before you destroy it.

MR. CLARKE: Thank you for inviting us.

CHAIR ABDEL-KHALIK: Mike.

MEMBER CORRADINI: I just want to thank GEH. I think the presentation is very helpful even for those that supposedly were supposed to remember this from 15 years ago. It was very, very helpful. I thank the staff also because now I think I understand the process. I was a bit confused with the process but I get it.

CHAIR ABDEL-KHALIK: I would like to add my thanks to both GEH and the staff for this presentation. It has been very informative and will be very helpful as we proceed along this path. Thank you very much.

(Whereupon, at 4:57 p.m. the meeting was adjourned.)