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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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EPR SUBCOMMITTEE

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TUESDAY

NOVEMBER 3, 2009

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ROCKVILLE, MARYLAND

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

SUBCOMMITTEE MEMBERS PRESENT:

DANA A. POWERS, Chairman

MICHAEL T. RYAN

WILLIAM J. SHACK

JOHN W. STETKAR

NRC STAFF PRESENT:

DEREK WIDMAYER

SANDRA SLOAN

GETACHEW TESFAYE

RONALDO JENKINS

JIM STECKEL

PETER KANG

JOE COLACCINO

CLIFF MUNSON

KENNETH SEE

BRAD HARVEY

WEIJUN WANG

ALSO PRESENT:

SANDRA SLOAN

GEORGE PANNELL

BRIAN GARDES

JIM REDDY

VIC FREGONESE

ZIA SALAMI

TODD OSWALD

TED MESSIER

T-A-B-L-E O-F C-O-N-T-E-N-T-S

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

8:30 a.m.

CHAIRMAN POWERS: Meeting will now come to order. This is the meeting of the Advisory Committee on Reactor Safeguards U.S. EPR Subcommittee.

I'm Dana Powers, the harassed and harried chairman of the Subcommittee.

ACRS members in attendance are: John Stetkar, virtually back from the exotic Swiss Alps; Michael Ryan from the Deep South; and Bill Shack from the rough and tumble world of Chicago.

Derek Widmayer of the ACRS is the designated federal official for this meeting.

The purpose of the meeting is to begin our review of the safety evaluation report, otherwise known as the SER, with open items for the design certification document, sometimes known as the DCD, sometimes known as the blankety-blank CD, submitted by AREVA NP for the U.S. EPR design.

Today we will hear presentations and discuss Chapter 2, Site Characteristics, and Chapter 8, Electric Power. The Subcommittee will gather relevant information today and report to the full committee later on this week, but we will not be formulating any findings on these matters at the conclusion of today's meeting.

The Subcommittee will meet again on November the 19th and hear presentations and discuss the SER for Chapter 10, Steam and Power Conversion Systems, and Chapter 12, Radiation Protection Model.

At the conclusion of the November 19th meeting, the Subcommittee members will decide what recommendations to take to the full Committee concerning these four chapters of the SER. The full Committee will meet on December 3rd through 5th, 2009.

The rules for participation today's meeting have been 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. However, if members of the public do have comments they would like to make, we will allow them time as is appropriate.

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 the meeting use the microphones located throughout the meeting room when addressing the Subcommittee. They should first identify themselves and speak with sufficient clarity and volume so they may be readily heard.

Copies of the meeting agenda and handouts are available in the back of the room.

I understand we have a telephone bridge and we have participants from AREVA NP on the line. And there are a variety of rules for participating, most of which is to keep your telephone on mute.

Do the members of the Subcommittee have any opening comments they would care to make?

(No audible response.)

CHAIRMAN POWERS: Seeing none.

Well, we're about to get started on this.

You ready, Sandra?

MS. SLOAN: I think we're ready.

MR. TESFAYE: I'm going to get started.

CHAIRMAN POWERS: You're going to lead it off? All right.

MR. TESFAYE: Yes, give a short overview of the project and where we're at with the project.

Good morning, everybody.

CHAIRMAN POWERS: We're going to let you

in just a second.

Okay. This is the first of what is it, 20 chapters altogether?

MR. TESFAYE: Nineteen.

CHAIRMAN POWERS: Nineteen? So, we've broken it down into about eight different sections to make life easy for ourselves. And then we'll get started.

So, Mr. Tesfaye, you were going to give us an overview. Please do so.

MR. TESFAYE: Good morning, everyone. Again, my name is Getachew Tesfaye. I'm the lead project manager for EPR design certification application review.

I'd like to give you a short overview of this project. This project will be almost five years old next month. The pre-application activities began back December 2nd, 2004, and for three years AREVA engaged the staff through public meetings, some meeting topical reports, technical reports, and then the application was submitted on December 11th, 2007. It was accepted or docketed for review on February 25th, 2008 and the staff issued a review schedule on March 26th, 2008.

We completed Phase 1 of the review,

which is developing a preliminary safety evaluation report and generating RAIs on January 29th, 2009, and that was done on schedule. During that period, the staff issued over 2,500 RAIs, and we continue to issue RAIs through Phase 2. To date we have issued over close to 3,400 RAI questions to the AREVA.

We have also revised the original review schedule twice based on response schedules that we received from AREVA and the current schedule that I'm going to show in the next slide was issued on June 25th of this year.

We have completed so far Phase 2 review for Chapters 2, 8, 10 and 12. Of course, Chapters 2 and 8 will be the subject of today's discussion. We'll start with Chapter 8 this morning and then we'll do Chapter 2 this afternoon.

The other major milestone of course, today we officially begin the ACRS review, which is basically off the review plan.

I think I have showed you this slide last month, I mean in September when we were here to discuss the -- AREVA presented the containment and some other accident analysis topics. Nothing has changed. This is the schedule that was published in June of this year. According to the current schedule, we'll be done with Phase 2 review June 30, 2010 and complete ACRS presentation of Phase 3 review on September 2010.

CHAIRMAN POWERS: Yes, your wording is correct. Those are target dates.

MR. TESFAYE: Target is exactly. They may change between now and the next presentation.

This is slightly rearranged to the ACRS Phase 3 review plan. As you indicated, we broke it up into several groups mainly based on the Phase 2 completion dates. We have groups 1A and 1B. This is was originally for a two-day ACRS Committee meeting. Since now they are separated by days, we call them 1A and 1B. And same thing with 2A and 2B. We'll finish about five more chapters before the end of this year. That is Phase 2 review of five more chapters. And we're going to bring six chapters in the next group, Group 2A and Group 2B, in February and March of 2010. And the third group will be presented in May. We don't have a date for it yet, but we're targeting May 2010 to present four more chapters. And then we'll complete our Phase 3 presentation in July with additional five more chapters.

And we're hoping to have one final

closing Subcommittee meeting in September to have a general discussion and sum up all the open items, any cross-cutting issues or even revisit some of the chapters that have already been presented.

So, that's our plan. Again, this plan may change.

With that, I'm done with my presentation unless there's any question for me.

CHAIRMAN POWERS: Yes, I'm not sure I have any useful questions for you.

MEMBER RYAN: No, nothing yet.

CHAIRMAN POWERS: That is the plan we're operating to and we will do our best.

MR. TESFAYE: Thank you.

CHAIRMAN POWERS: Sandra, I guess you're up.

MS. SLOAN: All right. While he's bringing up the slides, as Getachew said --

CHAIRMAN POWERS: Is there a reason for doing Electric Power before Sit Characteristics? I mean, is there some subtle, you know, topical element here that I'm just missing, or something like --

MS. SLOAN: No.

CHAIRMAN POWERS: Other than it makes

sense. We wouldn't be here -- if this plant doesn't generate electrical power, I don't care. I don't care where you locate it. If it just sits there and is a paperweight, you know, you can put it anywhere you want to, I suppose.

MS. SLOAN: Okay.

CHAIRMAN POWERS: Okay.

MS. SLOAN: So as Getachew said, this is first in a series of what we hoped were a constructive set of interactions with the ACRS Subcommittee to go through the chapter SERs with open items.

And our objective here today with the lead-off presentation is to provide summary level information about how the chapters is organized and the material in it. Obviously, given the constraints of the agenda, it really is a summary-level presentation, but we are trying to give you the highlights of what's in the design certification FSAR for EPR and taking to heart what you've told us in the past, trying to focus on those things that may be new or different for EPR. So not boring you with those things that are kind of business as usual for U.S. PWRs.

So, feel free to ask us questions as we

go along.

CHAIRMAN POWERS: Oh, we almost never hesitate.

MS. SLOAN: I know you don't miss an opportunity.

CHAIRMAN POWERS: Almost never. There are some members that I think maybe need encouragement, but in general, no.

MS. SLOAN: Not shy. Not shy.

And I did want to reiterate, we do have phone participants who are listening in Charlotte, North Carolina. So what we've instructed our presenters to do is if they feel like on a given question they need support from their colleagues, then they will address their colleagues by phone and ask them to respond to the question.

CHAIRMAN POWERS: It's a lot more fun to watch them squirm.

MS. SLOAN: So, we have our phone-a-friends.

PARTICIPANT: A life line.

MS. SLOAN: A life line. Yes, that's another way to look at it, I suppose.

CHAIRMAN POWERS: Hey, we can give them multiple choices, you know?

MS. SLOAN: But we'll start off. Our presenter today for Chapter 8 is George Pannell, who is one of our senior licensing managers in AREVA. He'll talk to you a little bit about his background. And he's also supporting --

CHAIRMAN POWERS: Oh, yes, George, that's right. Since you guys are all new here to us, you've got to give us some reason why you're qualified to speak before this august body.

MR. PANNELL: I'd be glad to do that. Yes, sir.

MS. SLOAN: And then he's joined by Brian Gardes and Jim Reddy, who are subject matter experts from AREVA who've been the leaders in developing electrical design for the U.S. EPR. And then after they cover the material that's included in Tier 2, Chapter 8, then Dr. Zia Salami, who's sitting here on the side, will give an overview of the electrical distribution system modeling and analyses.

So with that, unless there are any particular questions for me, I'll turn it over to George.

MR. PANNELL: Good morning. A little background on myself. I've been involved in nuclear technology for about 41 years now. I got out of the Navy in '73. Went to work for Virginia Power. So I've been involved in the start up of three reactors actually. I started up in North Anna 1 as an operations manager, North Anna 2 as an engineering manager, and Watts Bar 1 as a site licensing manager. And as you know, North Anna 2 was caught up in the post-TMI moratorium-kind of thing, so at that point in time I was responsible for electrical I&C, fire protection, EQ, and I performed the first human factors modification of an existing control room in the country at that time. That was 1980 vintage. And I had to do quite a few modifications to the distribution system to get that plant to perform a little bit better.

In the mid-'80s I ran an industry program, Westinghouse Owners' Group Trip Reduction and Assessment Program; you may have heard of it, WOGTRAP. I chaired that starting in '85 when we were having on average, if you counted all the reactors vendors, one-and-a-half trips a day. So, I think we turned that around a bit.

CHAIRMAN POWERS: Beautiful.

MR. PANNELL: And then in that same time frame I was part of the corporate emergency response team when we had to deal with the pipe rupture at Sorry, December of '86, and the six-hundred-gallon-a-minute tube rupture at North Anna Unit 1.

So the modifications I did to the electrical on North Anna 1 really helped us better manage that event. I mean, we had the generator bottled up in about 30 minutes and cooled the unit down. So, that was important.

And another kind of milestone, submitted a tech spec change, if you recall back when we were doing surveillance on emergency diesels, we were kind of testing them to destruction. So, I submitted kind of a precedent-setting tech spec change which allowed us to, when we do surveillance on like to warm the engine up, load it, instead of doing so many cold fast starts. That was another good thing.

So, that's kind of my background and what I've been doing.

So, what I would like to do today is present -- the first couple slides are kind of here's the machine and then we'll relate the electrical system to the machine.

So, we're going to talk about the four sections in the SAR, and then I've put together a summary to kind of wrap it up.

So, the basic layout of the machine is we have a four-week PWR and four safeguards areas. If it's okay with you gentlemen, I'm going to point rather than use the mouse. So if you can't hear me, just yell.

So, what we have is four safeguards areas around the reactor. And the overview layout plat plan of the station, important characteristics. The diesel buildings are on opposite sides of the containment. There are Safeguards 1, 2, 3 and 4 again. Station blackout diesels back here. Power transformers we're going to talk about are back here. Diesel buildings 1 and 2 are in the same buildings, but they're properly separated. The diesel buildings are on opposite sides of the containment building for additional physical protection.

The switchyard of course is COLA-specific. Our basic off-site power system consists of three what we call normal auxiliary transformers and two emergency auxiliary transformers, and they supply the emergency buses.

On-site power, we have several uninterruptible power systems, non-class 1E. We have the four divisions of class 1E. Four emergency diesels. That's a little bit different than a lot of plants. Then we have of course two station blackout diesels.

On-site power, non-1E UPS. Four divisions of 1E UPS and a 12-hour UPS system, which we'll talk about in a little bit.

So, what's fundamentally the same with the EPR that you've probably seen many times before.

CHAIRMAN POWERS: Can I ask you a question about your 12-hour interruptible power supply?

MR. PANNELL: Sure.

CHAIRMAN POWERS: Why 12 hours?

MR. PANNELL: Well, it has to do with station blackout and severe accident mitigation.

CHAIRMAN POWERS: Why 12 hours?

MR. PANNELL: That is long enough to get the SBO diesels back and control the plant, keep it stable. That's our engineering assessment of the situation.

CHAIRMAN POWERS: How did you do that?

MR. PANNELL: Brian?

MR. GARDES: Sure. As I said, I'm Brian Gardes and I'd better give my qualifications so at least --

CHAIRMAN POWERS: Go ahead. Please.

MR. GARDES: -- maybe you'll --

CHAIRMAN POWERS: Yes, I mean, this is the first time we meet you at the Subcommittee meeting. It's nice to know who we're talking to.

MR. GARDES: I've been involved with the EPR for about four years, same with AREVA. I've been in electrical design the whole time. So I've been involved in almost all the technical issues and --

CHAIRMAN POWERS: Did you suddenly appear out of the ether?

MR. GARDES: Nope. I came from Columbia Generating Station for 10 years, mostly in operations, including shutdown reactor --

CHAIRMAN POWERS: You survived the cultural shock from --

MR. GARDES: Well, I grew up in Maryland, so getting back to --

CHAIRMAN POWERS: Ah, so you -- I see. You're tired of looking at broad vistas and things like that. You wanted trees in the way to --

MR. GARDES: Yes, a lot of people think Washington State is all trees, but obviously --

CHAIRMAN POWERS: Not true then? They potted trees there.

MR. GARDES: And then nine years in the Navy on submarines --

CHAIRMAN POWERS: Oh, okay. What boat?

MR. GARDES: U.S.S. Guitarro.

CHAIRMAN POWERS: Oh, okay.

MR. GARDES: Okay. The 12 hours, that's basically a time duration that was developed from the European side and it was the duration set where they would expect to recover either the station blackout diesel, emergency diesel generator and/or the off-site power. And it was a duration of which the passive part of the severe accident design on the 12-hours UPS could manage the event until we had to get active systems involved that require a larger amount of power such as the severe accident heat removal system for containment spray and the IRWST cooling. So, it's both the time it takes to restore power sources and also to mitigate the event during the 12 hours. And that's the duration of --

CHAIRMAN POWERS: I'm still struggling. Why 12 hours? You say this came out of the European analysis. They have a very reliable grid, more reliable than ours.

MR. GARDES: That's true, but this is like a least improbable event. So, you know, you've already talked about loss of off-site power, the failure for emergency diesels, and in this case, the failure of two of the station blackout diesels, so you have no AC power source. So, whatever that took all those major AC sources out, you know, is fairly improbable, but at least it would take some amount of maintenance to restore one of the sources, whether it's the grid and the grid operator can bring a source back to off-site.

CHAIRMAN POWERS: But the median time to repair a diesel, it's eight hours.

MR. GARDES: Then the 12 hours would be a conservative duration.

CHAIRMAN POWERS: It's conservative on the median. It may not be conservative on the mean. I just don't happen to know what the mean is. But I mean, at least that would be a rationale for 12 hours.

MR. GARDES: And also I think the containment design is such that it's the design of the containment system, etcetera, for the severe accident, would the systems on the 12-hour UPS cover that 12-hour duration prior to needing to restore an active system for severe accident mitigation such as the severe accident heat removal system.

CHAIRMAN POWERS: I don't think it's the magic number. I think it's more of, given what Brian said, an engineering judgment. Got a design a system here, so that would be quantified.

MEMBER STETKAR: Let me ask you, I flipped ahead in the -- to interrupt. Are you done?

CHAIRMAN POWERS: Probably not, but please go ahead.

MEMBER STETKAR: I flipped ahead and I notice you aren't spending much time on the station blackout or the station blackout coping analysis, which is what we're really talking about.

You mentioned 12 hours is partially based on the time to recover off-site power. The switchyard design is completely outside the scope of the Certified Design for this plant. Except for the fact there's some mention of things like redundant DC control power supplies or some things like that, there's no specification on the expected life time of the switchyard batteries, as far as I can tell.

How do you get off-site power back into the site if you can't operate the circuit breakers? finite element, if the switchyard batteries have a life of, oh, 15 minutes or an hour, you're never going to get off-site power back into the site without some heroic efforts on the part of switchyard people.

So, I was curious what sort of assumptions you made about timing for restoration of power since you know nothing about how long people can actually operate circuit breakers out in that switchyard after you've lost all AC power. It could be days. Maybe not days. That's probably an exaggeration. It could be considerably longer than eight hours or twelve hours or sixteen hours or --

MR. PANNELL: Well, maybe I can relate to my experience of managing a couple of events. There's a lot of support when you have an off-normal situation, as you can imagine.

So, unless the site was just not accessible, you put a lot of things into motion when you have an off-normal event and you have a lot of support. So, even if you were to have some switchyard battery problem, you can get T&D out there to do some things fairly quickly, given that --

MEMBER STETKAR: Fairly quickly, and given the fact that off-site power often fails during storm events and things like that where T&D is busy doing a lot of things, that's a bit of --

MR. PANNELL: I agree. But again, it's engineering judgment. You're looking at a scenario, trying to make design decisions, looking at the trade-offs, looking at the probability of the event. So, yes, you could come up with some scenarios where the switchyard may be a problem, but you still have to account for a little bit of help from the outside. Believe me, when you're in the middle of an event, you call in all the help you need. So, you do what you need to do. And you can pick a number for the batteries; two hours, four hours, six hours.

MEMBER STETKAR: I was just curious because the life of the batteries out there do affect a station blackout coping duration --

MR. PANNELL: Oh, sure. Sure.

MEMBER STETKAR: -- inside the plant, even though you're not controlling the design of the switchyard. I was curious why there was no specification regarding possible life of the batteries, because in this particular plant they are distinct elements that affect the time available to restore off-site power.

MR. PANNELL: True. I don't think we have a better answer to that than what we gave.

MR. GARDES: The SBO coping duration for the EPR is eight hours before we do it. And even though it's COLA-specific the batteries will last, you know, longer than 15 minutes an hour. They're designed to last up to the coping duration of --

MEMBER STETKAR: I didn't see that anywhere in the FSAR though, that that's a requirement. It's --

MR. GARDES: But that's COLA- specific for the switchyard.

MEMBER STETKAR: Yes, because I didn't see a requirement that said that the COL applicant needs to account for that. It just says that they should have two redundant DC sources and all of that kind of good stuff.

MR. PANNELL: That's a good point. You're right. Correct.

MEMBER STETKAR: If you don't put it in there, the applicant can do whatever he wants to, he or she.

MR. PANNELL: Good comment. Thanks. Shall we move on?

CHAIRMAN POWERS: Please.

MR. PANNELL: So, what fundamentally is different generally speaking about the EPR electrical design?

We have four emergency diesels. That's somewhat different.

The alternate. We have what we call the alternate electrical feed configuration, and we're going to talk about that in a few minutes in more detail.

The diesel load sequencer is part of the I&C protection system. In older plant designs, those are kind of stand-alone timing-kinds of things that are triggered by what happens on the emergency (off microphone.)

We have two station blackout diesels. This bullet I think is an important one. No fast transfer of plant loads during start up, shut down or plant trip. In the older designs where you have start up transformers, station service transformers and you transfer the hotel load to the main generator and you lose the unit, you get a pretty good electrical transient in the middle of whatever else you're dealing with. Take the case of the tube rupture. We avoided that by having redesigned the distribution system. So it's just another thing that the shift supervisor has to deal with that we avoid with this design. So, it's a very stable off-site power source.

We have separate off-site feeds to safety and non-safety buses. Again, no main generator carried station service transformer, so you've got direct feeds from the switchyard to both sets of transformers. That's an important feature of the design.

We have what we call island mode; I'll talk about that in a minute. May address your question on the battery. And of course our 12-hour EPS.

PARTICIPANT: Sir, please keep your voice up when you're adjacent to the table.

MR. PANNELL: Oh, yes. Thank you.

This is the fundamental layout of the emergency power system. Two emergency transformers, two secondaries for load tap changers. So there's the four divisions, 1, 2, 3 and 4. And you can see how the power feeds are split, off-site power from the switchyard with overhead lines.

MEMBER STETKAR: George, you mentioned overhead lines. Is that required, or --

MR. PANNELL: No, that's just the way

we're approaching it for now.

These are the normal auxiliary transformers, and we've split the loads on the hotel system into 26 frames to balance the plant. Same thing, they have their own off-site feeds. As I pointed out earlier, in older designs these transformers would be potentially from the main generator. You'd swap hotel load. If you lost the unit, that load would have to go back to the EATs which presents some design challenges. So these get off-site feed. They're stable, regulated.

MEMBER STETKAR: Before you flip down to the on-site stuff, are you going to go back to the off-site? No, you're not. You're digging down deeper.

MR. PANNELL: Yes, we can go back.

MEMBER STETKAR: Well, let me stop you here. This design does not specify a main generator output breaker, is that correct?

MR. PANNELL: Right.

MEMBER STETKAR: So you can configure the connection from the main generator to the switchyard any way you want to?

MR. PANNELL: Yes.

MEMBER STETKAR: There's a failure modes

and effects analysis in the FSAR for the off-site power supply and things that you have up on this slide here.

MR. PANNELL: Yes.

MEMBER STETKAR: That failure modes and effects analysis extends out to the main transformers, which I guess is within your scope of supply. It does not address failures of the interconnections of the plant with the switchyard and how those interconnections may affect off-site power availability to the safety systems.

MR. PANNELL: Yes.

MEMBER STETKAR: For example, you make the point that if a main transformer fails, circuit breakers out in the switchyard will separate the main transformer. Well, if you have a unit trip, for example, and one of those switchyard breakers fails to open, there would be naturally some sort of backup protection relaying in the switchyard that will open up feeds to isolate wherever the fault is.

MR. PANNELL: True.

MEMBER STETKAR: Those feeds that are isolated could affect off-site power to one or more of your emergency power transformers, emergency auxiliary transformers.

MR. PANNELL: Sure.

MEMBER STETKAR: Why doesn't the failure modes and effects analysis or the design requirements specify anything about those connection breakers out in the switchyard?

MR. PANNELL: Brian?

MR. GARDES: I might pass that to Jim and COLA as far as the switchyard failure modes and effects and the departure between what's in the FSAR compared to what might in the COLA.

MR. REDDY: Yes, my name is Jim Reddy and I've been with AREVA and then on the EPR project three-and-a-half years, primarily responsible for the development of the Chapter 8 and the RAIs, answering those. Before that, eight years out at Columbia Generating Station where I was an equipment operator/reactor operator/control room supervisor. And then before that, 11 years in the Navy as an RO.

So, as far as the generator breakers or generator output breakers in the switchyard, that was essentially considered to be covered within the COLA responsibility since the switchyard itself is the under the COLA responsibility.

MEMBER STETKAR: Okay. I guess I'll wait until the staff comes up and see if they're happy with that, that way of drawing the dotted line in terms of responsibility.

MR. PANNELL: Sure.

MEMBER STETKAR: Thank you.

MR. PANNELL: Sure. I'll try and spend a little time on this diagram. This is the emergency power system again. And the reason I highlighted they things that I did, it shows you left to right the four diesels. And I have some key interfaces here I'd like to talk about a minute. You have four diesels. This is 6.9 kV. And we mentioned in one of the earlier bullets the alternate feed arrangement that we can perform on this unit. So, what I've shown for division 1, this is a source that can feed a bus in division 2. So this is the supply. This is load. Same thing is true from division 2. This is a source that can supply a division 1 bus.

Now, these are divisional pairs, we cal them. So only 1 and 2 can supply one another and only 3 and 4. They can't go from 1 to 3 or 1 to 4, or that sort of thing.

MEMBER STETKAR: You're going to talk more about --

MR. PANNELL: Yes, I am. I'm going to

go in detail on that.

So, that's why I highlighted those connections. That's an important aspect of the design. We'll talk about it in a few minutes.

We have two SBO diesels. Mentioned those before. I put these rectangular boxes. Diesel one can supply these two buses. SBO diesel 2 can supply these. That's important from a battery charger standpoint, get power back to those batteries.

Like I said, this voltage level at these buses is 6.9 kV.

MEMBER STETKAR: George?

MR. PANNELL: Yes, sir.

MEMBER STETKAR: Before drive down in, we're going to get into more details of the on-site thing --

MR. PANNELL: Sure.

MEMBER STETKAR: -- you mentioned island mode operation --

MR. PANNELL: Yes.

MEMBER STETKAR: -- which is a term that I'm familiar with, but I don't understand what it means in the context of this design. So --

MR. PANNELL: Well, let me see if I can

do it quick. We're talking about loss of off-site power and various issues. It basically is a configuration where you can have the main generator supplying the EATs and NATs and be divorced from the grid.

MEMBER STETKAR: Okay. So, that's the way I understand island mode. But it's typically where you have a main generator breaker and a more traditional --

MR. PANNELL: Right. Right in where you --

MEMBER STETKAR: -- alignment where you separate the plant from the switchyard.

MR. PANNELL: Right.

MEMBER STETKAR: -- have to feed the switchyard --

MR. PANNELL: Yes.

MEMBER STETKAR: -- and come back in.

MR. PANNELL: Yes, go out to the switchyard and back. But when you're in that mode, you're divorced from the grid basically and carrying your own hotel loads --

MEMBER STETKAR: Provided the loss of off-site power wasn't due to failures in the switchyard, which a good fraction are.

MR. PANNELL: Yes. Yes.

MEMBER STETKAR: Okay.

MR. PANNELL: You're exactly right.

This just gives you a feel. We talked about the safeguards divisions. We've picked division 2 because it has the main control room. But basically, the layout of the EPR, the fluid systems are below switch gear and I&C stuff. Main control room support systems up above.

So, we talked about emergency diesels. We have four to support the four division. Output is 9,500 kW. And again, the load sequencing in this station is performed by the I&C protection system, which is a bit different than you're probably used to seeing. And of course we have adequate physical separations within safeguards buildings, even with the EDG buildings where the diesels are beside one another, 1 and 2 and 3 and 4.

Alternate feed. This is an important aspect of the design, so we'll spend a little time on this and talk about it. They're designed to enhance operational capability and flexibility. What we don't say in that bullet is while maintaining complete Chapter 15 mitigation capability with the diesel. We're going to talk about that some more.

They can only be established, as I mentioned, between 1 and 2, 3 and 4. You can't go from 1 to 4. When you make the connection and going to alternate feed, you are supporting the systems that are basically two-train systems that you need. And I'll talk about Chapter 15. We'll walk through that here in a second.

These are the basic loads on the divisions. One thing that could be a little misleading, primary containment isolation valves. We show four Xs. It's really not four divisions. It depends on the systems. In some cases division 1 and 2 might power the inside and outside valve and division 3 and 4 on another. So that could be a little -- the PCIVs are not four-trains. They're just on occasion powered by different divisions. And then the bolded box are the two-train systems I mentioned. And we'll show how we retain that functionality when we talk about alternate --

MEMBER STETKAR: What's a KLC system?

MR. PANNELL: That's a cooling system for safeguards buildings.

MEMBER STETKAR: Okay. Chilled-water-type?

MR. PANNELL: Yes, forced cooling, recirc cool.

So, this is the basic concept, divisional pairs. I mentioned you can 1 to 2, 2 to 1, and of course 3 and 4. So the basic idea is I can supply the opposite division with the other division's diesel. In the next slide I'll talk about how that works. We'll take a diesel. The concept, just two pairs, divisional pairs.

So, let's assume we take diesel 1 out for maintenance. You're going to make the connection from division 2 to division 1. And I might explain that that is not an automatic transfer. That's a dead-bus transfer. So, basically what operations is going to have to do is maneuver whatever systems they had on that bus and downstream of that bus to make this transfer to being a 72-hour action. They'll do their transfer. Disconnect from the normal source, which would be div 1, connect to div 2, power the bus back on. Now you're out of the action -- does that make sense?

So, now you've restored at that bus level all the safety-related functionality you need in the station. So literally, you could leave that diesel as is, theoretically, and you still meet

Chapter 15 analysis.

Yes, sir?

MEMBER STETKAR: Let me ask about this one.

MR. PANNELL: Okay.

MEMBER STETKAR: Suppose we now have a loss of off-site power in this configuration.

MR. PANNELL: Okay.

MEMBER STETKAR: Let me see if I can phrase the question correctly here. You mentioned that there are not individual load sequencers for the diesel generators, that the loads are sequenced the --

MR. PANNELL: Yes, protection --

MEMBER STETKAR: -- protection control system.

MR. PANNELL: Right.

MEMBER STETKAR: Does the division 2 protection and control system sequence all loads onto diesel 2?

MR. PANNELL: Yes.

MEMBER STETKAR: How does the division 2 protection control system interface with the circuit breakers over there in your division 1 bus that you now have connected to division 2? It sounds like an inter-divisional I&C signal configuration that is not normal at all.

MR. PANNELL: Brian?

MR. GARDES: Sure. The actual connection from division 2 to division 1 will be done with manually operated breakers up from the control room/locally. So once you've put in the tie that will be from the 6.9 kV bus in division to the corresponding 6.9 kV bus in division 1. And if I have a loss of off-site power event, the actual main distribution breakers, I'm not going to open those main distribution breakers. They will stay closed. So, they won't have to be sequenced back in. So, when the diesel comes onto the orange, big orange bus in division 2, it will then come down and power up that smaller bus.

MEMBER STETKAR: Oh, you don't sequence any loads on the yellow bus, the division 1 bus?

MR. GARDES: Right now, potentially the only load we would sequence on would be the safety chiller compressors on there. The rest of the loads for the most part are smaller loads that would come with the distribution system.

MEMBER STETKAR: So there is potentially one load?

MR. GARDES: Correct.

MEMBER STETKAR: So let's focus on -- because I don't care whether there's one or a hundred. That's a division 1 circuit breaker that has division 1 DC power to it. It has normal division 1 protection control signals to it that is now potentially being told to close via a division 2 instrumentation and control signal. So I'm curious about how that's accomplished, because it sounds like we have inter-divisional control signals going on here, and I'm curious how that's done.

MR. GARDES: That's the requirement we have. As far as the actual Chapter 7 and the digital I&C and how it would be done, and protection and how it would be separated out within the signal spaces, I myself am not, you know, the technical expert in that particular area, although I understand your question.

MEMBER STETKAR: Do we have anybody who can answer that question, because I hate dividing up things up into digital I&Cs simply because that's a chapter in the FSAR, because this is an electrical question.

MR. PANNELL: Well, Mr. Fregonese --

MR. FREGONESE: Hi, good morning. My

name is Vic Fregonese.

I can comment that the protection system sends the signal still to the division 1 breakers and we're not transferring the function of protection system. What you're really doing is just taking the loads in the electrical system and transferring them over. We're not physically moving anything. So, the connections from the protection system still go from division 1 to division 1.

MEMBER STETKAR: I understand that.

MR. FREGONESE: Right.

MEMBER STETKAR: But if there is a single one or more loads on that yellow bus, on that division 1 bus, that must start and load onto that division 2 diesel generator after that diesel generator starts and loads. That's not a protection function. That's a signal to close the circuit breaker for that particular division 1 load.

MR. FREGONESE: And a protection system will still do that. The protection system doesn't know that the alternate feed is in. So, when you get an initiation signal, the coincident logic just tells the output of the protection system to send the outputs to every division complement that needs to be sequenced. So, it doesn't really know that the alternate feed is in place. So, you haven't done anything with the protection system. I'll try to clarify -- I'll clarify that again.

MEMBER STETKAR: I guess if I was a protection system, I'd like to know which diesel I'm loading onto, because it might affect the load.

MR. FREGONESE: No, Zia will talk about the analysis later as to how the diesels are sized. But what I will tell you is that all we need to do is close the breaker that supplies the load and the diesel can take that load. So in this case, we have not changed the function of the protection system at all.

MR. PANNELL: I can see your gears turning. What we'll have to do is look at that interface.

MEMBER STETKAR: I'm curious --

MR. PANNELL: Yes, you can design an isolated signal to that breaker.

MEMBER STETKAR: I can think of many ways of designing it. I'd like to see how it is designed, please.

MR. PANNELL: Yes. I know where you're going. But, yes.

MEMBER STETKAR: Yes.

MR. PANNELL: You'd have to have an appropriate isolated input to that breaker to control it.

MEMBER STETKAR: It's unusual because it is a cross-divisional I&C function.

MR. PANNELL: Yes, it is. You're absolutely right.

MR. FREGONESE: Yes, but once again, we don't change the mode of the protection system. And I guess we can clarify that later, if we need to, in another --

MR. PANNELL: That's a good point though.

MR. FREGONESE: -- in either Chapter 8 or Chapter 7.

MR. PANNELL: You must provide appropriate isolation if we send a signal from one division to the other.

MEMBER STETKAR: If there is a signal, it goes over. And if there isn't a signal, it goes over. Then I'd like to see how that really works in practice so that you don't miss loading possible loads onto that bus that you really need.

MR. PANNELL: Good comment.

MEMBER STETKAR: Okay. Thanks.

MR. PANNELL: Okay. So, let's go through this scenario where we have the alternate feed in place. And of course the most visible obvious thing is, oh, what if you lose that diesel or the alternate feed? Well, this is that scenario. And as you can see, we had this diesel in maintenance. This was carrying the alternate feed, its own division. We take that as have an event. Take that as a single failure. We still retain two divisions, the fluid systems, one division of the two-train systems we talked about earlier in the load chart. And so, in that condition with an event and a single failure, you can still mitigate the Chapter 15 accident.

So, same scenario event, different diesel. Same diesel out for maintenance. Actually end up with more equipment. You end up with the alternate-fed bus and again at least divisions of fluid systems and containment isolation.

MEMBER STETKAR: It's probably the time to ask this one, too, since we have the diagrams of various diesels available and out of service.

The design of the plant supports on-line preventive maintenance, and I'm assuming that's a planned activity.

MR. PANNELL: Sure.

MEMBER STETKAR: The tech specs allow a single diesel to be out of service for up to, I believe, 120 days, isn't it?

MR. PANNELL: Well, yes, that's what we propose.

MEMBER STETKAR: So that's a four-month maximum time. If people perform rolling preventive maintenance during plant power operation, there could be a measurable fraction of time when you're actually operating the plant in this alternate power alignment. I have no idea. There's no experience in the United States. I'm a bit familiar with plants in Europe where the kind of rolling preventive maintenance durations last anywhere from two to four weeks.

MR. PANNELL: Sure.

MEMBER STETKAR: And if that's the case, if you want to get through one maintenance cycle in a year or year-and-a-half, you could be operating in this alignment a reasonable fraction of time.

I just wanted to make that point and make sure that I understood --

MR. PANNELL: Well, I think --

MEMBER STETKAR: -- to the best

extent --

MR. PANNELL: Yes, the maintenance rule will some, too. You're probably not going to end up leaving that for an extended period. But the other issue we ran into in the past is having some sort of -- assuming it's not a common problem to the engine and trying to do quick maintenance on a big diesel engine. So, to me, that's a pretty good trade-off. Just make sure you get fixed properly.

MEMBER STETKAR: In terms of specifying that that 120-day tech spec time limit for the diesels, did you look at all at using the risk assessment approach to look at that time limit? The other time limits you have in there are fairly standard in terms of standard tech spec times. But the 120-day time limit is kind of a new beast, if you will --

MR. PANNELL: It is.

MEMBER STETKAR: -- in terms of our licensing world.

MR. PANNELL: Yes.

MEMBER STETKAR: Have you looked at risk informing that duration at all in terms of risk sensitivity to what it might be?

MR. PANNELL: No.

MEMBER STETKAR: Thank you. Continue.

MR. PANNELL: Thanks. Again, this is the normal transformers. The purpose for this slide is simply to show where the SBODs will tie into the non-safety. And so you can see the same four rectangular orange boxes I showed on the emergency. And then it eventually ends up feeding the emergency power system the way I showed earlier. It's just to show where the SBOs tie in.

So, class 1E uninterruptible power. We have four divisions, two battery chargers per, and they're capable of being fed by the SBO diesel. Remember those four orange boxes I showed you on the safety buses.

And we had redundant feeds to the I&C cabinets, and I'm going to talk about that in a minute. It's a little bit different than you're used to seeing.

We learned a lot from having looked at the Forsmark event. If you recall, that event started with a fault in the switchyard and kind of went downhill from there. So some of that drove some of the things you're going to see in this design in terms of not losing invertors, UPS systems. If you remember, two divisions of batteries kind of were un-powered for awhile. That's not a good idea. So, we'll talk about that a bit.

So, a basic UPS arrangement. Circles around a battery. You've got a 250-volt battery bus. Two battery charges that can support the DC loads.

We have an invertor with a static switch. Should be a bumpless transfer of the invertor probes for some reason. That should swap over to that power source.

MEMBER STETKAR: That's the plan.

CHAIRMAN POWERS: Anyway.

MEMBER STETKAR: They work.

MR. PANNELL: They usually do, yes.

MEMBER STETKAR: The newer ones work.

MR. PANNELL: Yes. Yes. And then you have of course from the same MCC that supports the static switch, kind of a maintenance connection. So if you have to take that invertor out, you can work on it.

This is the interface we talked about earlier, kind of related to the Forsmark. In typical designs you have the old battery invertor supplies the I&C cabinets. Well, that's the left hand device. In this case, we have both an AC to DC feed to the I&C cabinets and a DC to DC feed.

MEMBER STETKAR: George, are those feeds cabinet-by-cabinet, or are they division-by-division?

MR. PANNELL: I don't recall.

MEMBER STETKAR: For example, division 1 cabinets, is there a single power supply that feeds all of the I&C cabinets in a particular room, or are these isolated by cabinet-to-cabinet?

MR. PANNELL: I don't know we split it.

MEMBER STETKAR: Because again, it's the interface between I&C and electric power, but --

MR. PANNELL: Right. Of course they're optioned here together.

MEMBER STETKAR: Yes.

MR. GARDES: It's definitely division-by-division. So when you look at a division, you have division 1 power, both AC and DC, to division 1 I&C cabinets. The converter modules could be kind of considered like battery cells where you have several modules in a cabinet, and it could supply several I&C cabinets. But you'd have more than one converter module per se cabinet in a division because of the number of I&C cabinets. So, this could represent a cabinet here and you could have potentially three or four cabinets that have these modules supply X-number of I&C cabinets in that division. And the same with these cabinets.

MEMBER STETKAR: That's what I was trying to get a handle on, whether if I think of this as division 1, do I have two and only two of those devices, you know, once each, or do I have 50 of them if I have 25 individual cabinets?

MR. PANNELL: Like one big bus versus --

MEMBER STETKAR: One big versus distributed power supplies.

MR. GARDES: More than one, less than 50. But I think if I had to guess, as far as the number without having to look at the thing, we're probably up to maybe five or six cabinets, converted cabinets per division supplying X-number of I&C cabinets. So, probably around a half-a-dozen or so.

MEMBER STETKAR: And this design does not have alternate feeds to I&C from the other divisions, right?

MR. GARDES: It doesn't have alternate feeds as far as it's concerned down here at the I&C cabinets. But if you go up above to where the battery chargers --

MEMBER STETKAR: They'll cross ties at a higher level?

MR. GARDES: That's correct.

MEMBER STETKAR: But down at the cabinet level, it's strictly divisions?

MR. GARDES: That is correct.

MEMBER STETKAR: Okay.

MR. FREGONESE: This goes back to your previous comment. This is Vic Fregonese. This kind of illustrates what we were talking about before with the alternate feed and sequencing. The I&C system always stays powered up. So the logic, the processors in the sequencing is always powered up even in the alternate-fed configuration. So the output of the system still goes to the division 1 breaker, even though the bus is powered from division 2. So, that breakers always gets the same one from the I&C based on the coincident logic that's developed. So, the cabinets are powered up. We never take the division 1 I&C out when the division 1 diesel is out.

MEMBER STETKAR: I'll leave it open on the table, because --

MR. PANNELL: Oh, okay. Thank you.

MEMBER STETKAR: -- the I&C signals

often need to know what the configuration of the AC electric power system is.

MR. PANNELL: Yes, I've had to deal with some of that stuff.

We were talking a little bit about the 12 hours UPS, two trains. Part of it's for SBO control. And this plant actually has designed into it severe accident mitigation capability. Core areas under the vessel, spray systems, etcetera.

We mentioned island mode. It's actually pretty straightforward given you can work out the switchyard breakers. You basically end up with the unit being self-sustaining, if you want, powering its own hotel loads, divorced from the grid.

COURT REPORTER: Please keep your voice up, sir.

CHAIRMAN POWERS: Yes. Station blackout. We mentioned we had two SBO diesels. They can be connected to divisions 1, 2, 3 and 4, as we showed earlier. Thirty-nine-hundred kW. And they're different, intentionally of course, to be diverse. Engines. Different areas. Even different cooling. Larger engines are water cooled. Smaller ones air cooled. No common systems, and they can be put in service in ten minutes.

MEMBER STETKAR: Two questions before you leave this one.

MR. PANNELL: Sure.

MEMBER STETKAR: I looked enough at the design and basically understand the philosophy. When you say there's no sharing of fuel systems, does the plant design include a common large fuel oil storage tank that's used to refill the individual tanks for each of the emergency diesels and the station blackout diesels? Some plants have that large storage capacity.

MR. PANNELL: Right. Right. I'm used to that.

MEMBER STETKAR: Other plants simply have individual tanks for each diesel. So, I was curious about that possibility of a common large on-site fuel storage capability.

MR. GARDES: I'm not aware that there is a common fuel storage tank. Each diesel, whether it's emergency or SBO, has its own fuel oil storage tank associated with it. And I'm familiar with what you're saying about a common tank that you can --

MEMBER STETKAR: Make a -- right.

MR. GARDES: -- or a spoiler, whatever. But, that's not in this design. Each one is a storage tank stand alone.

MEMBER STETKAR: Is there a specification to prohibit that in terms of the COL? Because that indeed would be a source of commonality in terms of contaminated fuel among --

CHAIRMAN POWERS: Sure. That's quite an old issue. You're going to have the same thing just on delivery. It doesn't matter --

MEMBER STETKAR: Except delivery is often different times. So, you can argue that it contaminates --

MR. PANNELL: Yes, I think currently sampling-kind of requirements kind going to take care of that.

MEMBER STETKAR: I'm going to ask the staff about this. I'll wait and ask the staff about the 10 minutes.

MR. PANNELL: Okay. Sure.

So in summary, the design meets regulatory requirements, protects the health and safety of the public. And this is key; again, based on my experience, the goal here is to provide the operating staff with a stable power supply system. So, if they have to deal with some off-normal event, they have the equipment they need, whether it's safety-related or not to manage that event. That's extremely important. So having a stable power supply is a very important aspect of this design. So, it provides stable power for normal operations and for event management, which is very critical.

We think it's evolutionary. We certainly stayed abreast of what's been going on for 30-35 years, tried to incorporate those lessons learned.

Again, the off-site emergency bus transformer feeds are separated from off-site non-safety bus transformer feeds. There is no large load transfer when you lose the unit. That's again an important aspect for operational folks.

No shared transformers between safety and non-safety and the non-safety loads are not powered from the main generator, which requires typically a large hotel load transfer.

We have more redundancy than you've probably seen before in older plants. And the alternate feed provides a key power supply so that you can take a diesel out, do good maintenance on it, but still be protected as far as Chapter 15 events go.

That's all I had.

MEMBER STETKAR: This is an off-the-wall question, more off-the-wall than the other ones.

There are, as I understand it, a relatively large number of underground cable ducts that get power from point A to point B in this plan. I think the FSAR mentions ducts for essential service water, the station blackout diesels, the power to the safeguards buildings and so forth.

We've had substantial operating experience here in the United States with water intrusion into underground cable raceways and cable ducts. And I noticed that the FSAR acknowledges that, and it says manholes for duct bank access had recesses for temporary sump pumps for water draining. Manholes located below the groundwater line had a permanent sump pump design.

I was curious, given the experience with water intrusion from a variety of known and unknown sources here in the U.S., many of which are very, very plant-specific and some of which are not entirely understood, I think, why you don't just put permanent sump pumps in all of the low points in all of the cable ducts just to keep them dry, regardless of whether they're above or below nominal groundwater level?

MR. PANNELL: I think that's a great question. Again, I'm relating back to my experience. Even if you, in my view, put permanent pumps in, I wouldn't totally rely on those.

MEMBER STETKAR: Oh, yes, you still have to look in there, because --

MR. PANNELL: You likely think they're always going to work, but --

MEMBER STETKAR: But having a sump pump versus no sump pump is --

MR. PANNELL: Yes. Absolutely. That's right.

MEMBER STETKAR: -- better than just relying on some periodic --

MR. PANNELL: Well, I wouldn't totally rely on it without some periodic look in the hole and see what's going on.

MEMBER STETKAR: There was apparently and active decision made not to put pumps in all of those ducts for some reason.

MR. PANNELL: I can't address that one, no.

MR. GARDES: I'll pass that to Jim, because we took an RAI question on that as well, as far as the cabling and underground issues.

MR. REDDY: Right. And with the RAI, essentially what we determined there was the -- and then you mentioned the experience there with, for example, Generic Letter 2007-01. Essentially we're to create a COLA item for at least the periodic inspection of those. And then at the same time, you know, if there were to be a permanent sump pump design in there, that that would be, you know, within the COLA to do that. But at least to recognize what you're saying that it's, you know, certainly a problem to be considered and addressed, and at the same time to acknowledge it, do the appropriate inspection. And if you needed to do or if you elected to have a permanent sump pump design, then you would do that at the site-specific, or you would know what your water tables are and so forth.

MEMBER STETKAR: Well, what we've seen in many cases, it isn't so much a function of the water table. It certainly depends on the water table, but there's also water intrusion from surface water runoff, from rainfall, from you name it, snow melt.

MEMBER RYAN: Could I ask you a question, John, somewhere along in here?

The groundwater question is a

particularly interesting one, and it's very site-specific. But, you know, you could end up with a circumstance where pumping isn't going to do much good. The minute you shut them off, you're back to where you started. So, what's plan B?

MR. PANNELL: Well, I don't know of any other way to address it other than know what the site conditions are at the time. And if you suspect that potential, there's a foot of water running on the ground, you're probably going to have to look at those and see what's happening.

MEMBER RYAN: Well, in a large part of the Southeast, groundwater is pretty close to the surface, if not at the surface.

MR. PANNELL: Yes. Oh, yes.

MEMBER RYAN: So, you can end up with a saturated water condition no matter how hard you pump.

MR. PANNELL: Oh, yes.

MEMBER RYAN: So is the alternative some kind of waterproof cabling?

MR. GARDES: Jim can correct me if I'm wrong, but I believe the actual mitigation used for the underground duct banks again would be COLA-specific, site-specific, because you know, there would be existing plants, you know, most likely at these locations that already have designed in certain features. And when they look at that, they'll have to evaluate for the site location. Some from a generic aspect, it's hard to come up with the solution. And that's a COL item where the COLA applicant will have to come up with the solution that best solves that particular issue.

MEMBER RYAN: But the guarantee is not there that you can get the water out.

MR. PANNELL: That's right.

MEMBER RYAN: That's my only caution. You could end up with a situation where you will be saturated whether you like it or not. And there's been a lot of blame assessed for rainwater running in, and I'm not convinced it's all rainwater running in.

MR. PANNELL: Well, the other issue is not just wetting. Our experience has been wetting and drying.

MEMBER RYAN: Wetting and drying.

MR. PANNELL: Pretty soon the thing breaks down and you got to --

MEMBER RYAN: Well, it could be in a circumstance where pumping against the hydraulic head of the dry water is bad.

MEMBER STETKAR: Mike made a good point. You haven't specified submersible qualified cables for these underground duct banks, have you? They're all just standard cables, is that correct?

MR. REDDY: That's correct.

MEMBER STETKAR: Okay.

MEMBER RYAN: And I do appreciate the COLA comment, that it is very site-specific, but there may be a wider range of options needed to address --

MR. PANNELL: Yes, it's a somewhat tricky issue, even the access. Can I actually inspect well enough if I put these --

MEMBER RYAN: Right.

MR. PANNELL: Can I see what I need to see?

MEMBER RYAN: Absolutely.

MR. PANNELL: It's an interesting --

MEMBER RYAN: And how many inspection ports are you going to have?

MR. PANNELL: Yes.

MEMBER RYAN: Are they ever hundred feet or every thousand feet?

MR. PANNELL: Yes, exactly.

MEMBER RYAN: Or how do you line that up?

MR. PANNELL: It's an interesting problem.

MEMBER RYAN: Yes.

MEMBER STETKAR: But the duct bank writing and duck back design is all part of the Certified Design?

MR. PANNELL: Correct.

MEMBER STETKAR: The COL applicant has no control over the actual physical configuration of the duct banks, unless they want to take an exception to the Certified Design. Is that right?

MR. PANNELL: Right. I think that's the case.

Anything else, gentlemen?

MEMBER RYAN: Thanks, John. Thank you.

CHAIRMAN POWERS: You're getting altogether too friendly. There's supposed to be a tension. Lots of happy smiling tension.

Sandra?

MS. SLOAN: All right. We'll turn to Dr. Zia Salami.

If you could just give a little bit of your background?

DR. SALAMI: Sure. Good morning. My name is Zia Salami. I graduated in 1992, '99 for B.S., M.S., University of Alabama. 1998 --

CHAIRMAN POWERS: Actually, you didn't really pick up the accent at all.

DR. SALAMI: Everybody telling me that.

CHAIRMAN POWERS: I guess that's not required, right?

DR. SALAMI: Well, pretty much. But, I had a lot of friends; we were so close. They forget out my accent. They didn't care.

But, then moved to North Carolina. Graduated in 1998 University of North Carolina. Since 2000, I've been working with AREVA than 11 years. My main responsibility was regarding responsible for electrical calculation and analysis. 2004, I got responsibility going to -- '03 for responsible for electrical design, model development and calculation. I was leading their electrical distribution system model development and all the calculation. Came back 2006, two years experience. And since then joined U.S. EPR supporting EPR and leading again in electrical calculation analysis and model development for U.S. EPR and also all the COLAs and later on.

I have a brief presentation regarding model development and electrical calculation and analysis and the approach. Then we're going to look at the system evaluation and the result, and finally the conclusion.

The main objective of our task, our team, was to make sure that what George mention regarding the electrical distribution system can be designed, is adequate and it can perform its function during the worst case scenario, worst case loading scenario, worst case configuration, either the power is fed from on-site or off-site, with worst case condition of the voltage and the grid condition. In order to achieve these objective, we have several design criteria, or I'll call it index. To me, if you could able to achieve those objective, therefore you could claim that electrical distribution system is adequate and can perform its function either safety or non-safety.

I have a few items listed here. That's the major item that to me that needs to be achieved for electrical distribution system. Make sure the continuous and short-time loading, make sure occur, make sure circuit capability are met. To make sure that we have voltage acceptance criteria, acceptance voltage current and power flow throughout the system and to make sure that we're able to provide this equipment base on the standard and availability. I have a few example on this item later on during my presentation.

CHAIRMAN POWERS: Help me understand. When you say "model," you're setting up a mathematical model of this system?

DR. SALAMI: That is correct. Simulation model which have all the components in the electrical distribution system.

DR. SALAMI: Molded in a steady-state-kind of fashion?

DR. SALAMI: Yes, sir, that is correct, sir. In a steady state condition --

CHAIRMAN POWERS: You're really not solving differential equations here?

DR. SALAMI: Correct, sir. Static analysis, or as you mention, a steady state, because during the early phase of the project, providing the dynamic model would be not wise because the parameters are so sensitive and the result would not be any good. Therefore --

CHAIRMAN POWERS: Yes, I was just trying to understand.

DR. SALAMI: Sure.

CHAIRMAN POWERS: In no way a criticism, because I'm --

DR. SALAMI: Sure. Sure. I will get --

CHAIRMAN POWERS: -- going to come down to the heart my question here in a second.

DR. SALAMI: I will get to -- I have a few slides on the electrical distribution system model development and I'll show you later on.

CHAIRMAN POWERS: Now, you're going to introduce into this steady state model a disruption?

DR. SALAMI: That is correct, sir.

CHAIRMAN POWERS: How do you do that?

DR. SALAMI: In order to create the model, therefore, if you go to the next slide, that is the steps that we're going through to provide and to achieve model development. I'm going through one step at a time and I hope I can answer your question during my next few slides.

The next step that we had to do is selecting a software that can be using a simulation and can be done for electrical analysis. AREVA adapted ETAP as a major software to do perform its study during the -- not only for U.S. EPR, also for operating unit for at this point. ETAP is V&V

software base on the QA requirement and standard. And at this point, base on their Web site, 90 percent of nuclear power utilities are utilizing this software to perform their analysis and calculations.

The next step was to define and assume conservative and bounding assumption and methodology. I have one sample example later on in my slide.

Then create the model and imprint the data, because again, data is also the major part of the model development and the data for the models for the cables, transformers, buses, switchyard circuit breakers.

Next step would be after creating the model, creating the configuration, because the power may be fed, as George mentioned, from the outside switchyard. The power may be fed from the emergency diesel generator, or maybe SBO. You have to analyze each alignment or configuration to make sure during that alignment and configuration the system and component can do their function. I'll show you a few configuration in next slide on my presentation. Also, power can be from the DC battery source.

CHAIRMAN POWERS: Let's go back to your

data.

DR. SALAMI: Yes, sir.

CHAIRMAN POWERS: You made a truism. You've got to put in and describe the components in ETAP.

DR. SALAMI: That is correct, sir. You have to put the data in component of ETAP?

CHAIRMAN POWERS: How do you do that? You haven't built the plant yet.

DR. SALAMI: In order to do that, for example, as I mention in found conservative and bounding modeling approach and philosophy, you have to assume in case you don't have a typical data, first you have to use a typical data. If is not available, is it plant data? And if it not available, you have to assume some conservative parameters. For example, or in some case we used ETAP library, because the library is a conservative number and is check base on the manufactured data. Therefore, we have a document; we call it ETAP Rule Development. In that document, we define each component, where the data coming from. For example, where the data from the model is coming from. What is the, for example, local current would be the conservative local current to use for medium-voltage? What is the power fact efficiency, the conservative number would be used for the model and so on? Static load. What would be the conservative power factor that you have to use for the static load? For the cable, what would be the length or the impedance or the size that you have to?

Therefore, we define all the equipment parameters that later on that you will see in the model. In ETAP Model Development and Rule Book, we call it, and define where the data coming from. Typically, if we have base on the -- sometimes the data coming from the industrial data, or from experience or, I mean, from other plant data. Therefore, we collected all the data with corresponding references documented in our rule book. When we get --

CHAIRMAN POWERS: Well, I guess I'm a little puzzled. Suppose I go through this and I take conservative on everything. Do I end up with a conservative model?

DR. SALAMI: Exactly, sir. For example, I have one example in the following slide and show you one of the way of modeling methodology and assumption that we made and why that causes the model to be conservative. Again, I can go through all the element and component and describe what we use for to complete model to be a conservative model.

For example, let me just give you a few now. On the grid voltage variation, we assuming plus/minus 10 percent on the grid voltage variation. Typical grid voltage variation in U.S., I cannot see more than -- well, I cannot say 100 percent, but pretty much plus/minus five percent. Therefore, we assuming that range of variation to make sure that we are cover the entire electrical distribution system within that. On the transformer impedance, for example, we using the conservative percent tolerance for each component. For the cable length, we assuming plus/minus some percentage for the error and the conservatism. For a motor, for example, we using the worst case local current to make sure when we start the component, when we start the motor we have a largest local current that cause that worst case voltage to get throughout the system.

Therefore, and one sample example in this one that I'm going to through that, why the model is conservative. This is just a small test, a few buses system and trying to show you how we model the electrical distribution system in medium-voltage and the low-voltage. Throughout the model development, we model entire medium-voltage load regardless it's a safety or non-safety, including again, the worst case parameters for which that component. For the LV system, as we know that the worst case and the weakest link in each plant is a component down connected to MCC, or a small load connected to low-voltage system MCC or load center. One of the approach that we selected here to make sure that low-voltage system is conservative and bounded I'm going to discuss.

In addition to this description, I need to mention that we have a load list contain 5,000 elements of the load, probably 85 percent low-voltage, 15 percent medium-voltage. Therefore, 15 percent medium-voltage was model for entire -- this is a cycle I got 6.9 kV system, 480-volt load center, 480-volt MCC, just a portion of this, our electrical distribution system. We have 5,000 component in the load list. If the load list -- for example, in this MCC1 and MCC2, we took approach, we call it equivalent modeling. We assume all the load connected through this MCC and add 10 percent addition to that, and we model it as equivalent load for the other MCC. The same for the load center.

Then we went through process of selecting the transformer. We add additional 10 percent to total connect the load and select a transformer base on this standard. When you select the transformer base on this standard, typically you get more than 10 percent margin. Because, for example, if you have 1,000 kVA load, the next available transformer size is 1,500. Therefore, we had to force selecting that 1,500 kVA transformer.

Now, what we have done, we add additional load beside what we have in the load, least on the top of 10 percent, to make the total connected load from LV system to be equal of the transformer kVA. What we have done, we force 400 kVA load in addition to what we had to make sure the low-voltage system here equal to transformer kVA.

Now, what this gives you: More power, more loading the system, of course more voltage drop. Since we model all the load as I mention as a motor load, that motor contribution short circuit throughout the system and also the power flow and the current going through steady state current and power flow going through the system for selecting of the circuit breaker, bus rating, so on, with all the maximize, as I mention.

This is one of the assumption and conservatism that we took to model the LV system. Just show you one example. Again, we have document all this assumption and conservatism and bounding condition in our ETAP rule.

Here is ETAP model development for electrical distribution system for U.S. EPR. As I mention, we model all the load on the LV system and the low-voltage we went using the equivalent modeling. The red one is the safety system, EAT. There are two transformer connected there. The yellow is NATS supplying power to TI. The color one, the yellow one. Again, as George mention, we try to separate the safety and non-safety system. Because, as you know that the largest load are connected to non-safety system. For example, reactor coolant, RCP, main feed water pump, those are huge. Starting those component wide separate of the way we have will not impact on the safety-related component which are located on division 1, 2, 3 and 4.

Just a big picture description of what we have here. Thirteen-point-eight from non-safety coming from three NATs supply power to reactor cooler pump in the blue. They are located in nuclear island. Here are located on turbine island. Two EDS supplying power to four divisions. One of that also design that we did, that one transformer can handle all, in case of the failure of one transformer can handle all the loads. For example, if you lose one of the transformer due to some internal problem or malfunctioning of the transformer, all the load can be transferred to one transformer.

The same here. If you lose on NAT, we designed the system that all the load which supply come from that NAT will transfer to the other two NATs. Therefore, the advantage would be that we would not be downs time in case of the transformer failure. Transformer failure, especially the ops transformer failure will happen. Actually, I was reading a few months ago some plant lost one of the aux transformer and it was down for several weeks.

Now, in addition we have a cooling tower area that is about 2,000 feet from the turbine island in green, and aux and rad building. As you see here, this is a configuration that the system is power-fed from the switchyard.

Next configuration, the first one I just mention, we analyze it for the voltage dip, the short circuit characteristic and also power flow. The other configuration, as you see here, the system on the safety is fed from the EDG, EDG train one. And this is an example. Supply to its own division and also supply power, as George mention, and Brian, to alternate-fed loads that are located in the division 2. The way we design the system that we connect all the load that needs to be power for the alternate loads in one switch gear. Therefore, the power from here going to the other 6.9 kV and all the loads are here designed to be used for alternate load and to do the function.

The next one here, we just have the SBO configuration. Again, we have analyzed the SBO configuration. SBO located here in train one, supply power to division 1 and 2. There are two line here. One goes to division 1. One lines go division 2. Again, we analyze the system to make sure if the power is fed from the SBO. The system can handle and the equipment can perform their function.

After creating the configuration, now we have to perform the study and simulation. We have done such as load flow analysis, short circuit, motor is starting and also the equipment sizing.

After going through the simulation and the study, you have to compare, make sure -- if you remember the objective we establish on the first page, we achieve that. We can say that equipment or within the steady state and short time rating are met. Equipment are within the short circuit capability. The voltage current power flow throughout the system, each configuration are met, meaning within acceptance criteria. Just give you an example what I mean with that. If the medium-voltage is supposed to start at 75 percent at the terminal, therefore we had to make sure in worst case scenario be able to supply the voltage at that terminal 75 percent and of course plus other margin that we have established.

Make sure the equipment are available base on the standard and the electrical distribution system can be -- just example for this one, typical 15.8 kV switch gear breaker is maximum is 63 kA with 170 kA interrupting capability, asymmetrical. If you had designed that, we had more than 63 kA, therefore you cannot find the circuit breaker that achieve your objective. That's why that I mention that we need to make base on the standard and availability, I was referring to that.

We can say base on the result that I provided here and is documented that U.S. EPR are verified to be adequate and acceptable.

And the conclusion again that electrical distribution system adequately supports the supply equipment to perform its function. Again, can be safety or non-safety function. And it does.

That had just a short presentation or combining just a few year's work on this area for U.S. EPR. We'd be happy to answer any question. And if I could, if I answer your question when you ask me, please?

CHAIRMAN POWERS: Well, I guess my principle question may turn to the staff. Is this model actually used in the safety analysis? I mean, most of the things you spoke of, if I were a customer and buying one of these, I'd want to -- you'd be here for days.

DR. SALAMI: Sure.

CHAIRMAN POWERS: But it's not clear to me that this really figures in the safety analysis.

MR. TESFAYE: I guess we'll address that when we make our presentation.

CHAIRMAN POWERS: Okay.

MR. TESFAYE: In the next session. I

mean, after the break.

CHAIRMAN POWERS: Yes.

MR. TESFAYE: Would you like a response now?

CHAIRMAN POWERS: Well, what I'd like to know is how much torture am I going to put Dr. Salami through here.

MR. TESFAYE: Could I --

CHAIRMAN POWERS: Because I mean, if you're not using this in any part of the safety analysis, then I'm not going to torture him.

DR. SALAMI: Maybe I just can add something which maybe not directly answer your question. Maybe you're thinking about safety evaluation. For example, when we have a alignment from EDG, as you see here, we establish that we able to start the component if the power fed from the EDG. The motor can start under the condition that it's power from the EDG. To me, EDG is a safety function and --

CHAIRMAN POWERS: It makes you enormously confident and it makes Sandra enormously confident. The question is, did it make these guys enormously confident?

MR. JENKINS: This is Ronaldo Jenkins,

electrical engineering branch chief. Typically, these kinds of analysis are used to support the design assumptions that are in any kind of electrical equipment because they are intricately tied together. So, if you're doing a very involved analysis to set the set points, that equipment would in fact start and support safety loads. It has to be backed up in most cases by analysis, and that's presumably what they would be using this for. You would also have verification by checking that model with actual voltage measurements.

Does that answer your question?

CHAIRMAN POWERS: I don't know whether that answers my question, but pretty close I would say.

MR. JENKINS: Okay. I think, you know, it depends on how you're using the computer, any computer model for a safety-related application. Do use it just to simply establish what the design -- you know, whether the design in fact is adequate, or are you using it on an ongoing basis? And so, the requirements, in terms of the regulatory requirements, are a little bit different. There would have to be some tests to verify that the model in fact that you're using is correct.

CHAIRMAN POWERS: Well, ETAP is a relatively well-known model.

MR. JENKINS: Yes, ETAP is widely used throughout the industry. But you still have to look at the assumptions that in fact goes in the model.

CHAIRMAN POWERS: Yes, I mean, I think you guys looked at the safety systems outside of the model and they can do anything they what with they're model.

MR. JENKINS: Right.

CHAIRMAN POWERS: But you still got to have a safety system that works.

MR. JENKINS: That's right.

MEMBER STETKAR: I would ask you a couple of questions. Have you used the model to look at breaker setpoint coordination, low voltage up to high voltage, throw a bolted fault to ground for example, on a low-voltage motor control center and make sure that the feeder breaker to that motor control center opens before the feeder breaker to the 6.9 kV bus and so forth?

DR. SALAMI: As a quick answer to your question, no, sir.

MEMBER STETKAR: You have not?

DR. SALAMI: No. And the main reason is

that we have done the fault analysis and to make sure selecting the circuit breaker and circuit breaker sizing, for example. What size we need interrupting, the asymmetrical or symmetrical interrupting. In order to do the prediction and coordination which I exactly know what you're referring to, we need to procure the equipment. We need to get the time current characteristic curve. And then we need to have a component that we know how that component operates and where is the setpoint, how we can set it to. Therefore, that would be a next step during the detail design phase that after we procure the equipment and providing and the manufacture provide us with equipment, including the time current characteristic. We going through that process that to make sure the feeder breaker will trip before the incoming break here. Or if need any setpoint to be adjusted in case of, for example, power circuit breaker, you need to make some adjustment. If you need to make -- what type of power circuit breaker you need to set it. Or on the medium-voltage relay, what to be set. Therefore, that is the process.

MEMBER STETKAR: Is that then COL scope of work?

MR. REDDY: Yes, the analyses that Dr. Salami are talking about, those would be used to support and help close out the ITAAC that's associated with the protection of coordination aspect of the ITAAC.

MEMBER STETKAR: Understand.

CHAIRMAN POWERS: It sounds like this all moves to ITAAC.

MEMBER STETKAR: Yes, it is. I was just curious how much they've done, you know, in terms of -- you can specify certain things, you know, from the design side.

In the FSAR it mentions that you've also used ETAP to evaluate the DC system. Is that correct? You focused totally on the AC system here --

DR. SALAMI: Right.

MEMBER STETKAR: -- which is interesting to a lot of people.

DR. SALAMI: Sure. Is more colorful picture.

MEMBER STETKAR: It is.

DR. SALAMI: And the DC, you only have one bus supply, a few buses. Yes, we have done that on the safety two hours UPS system. We model the battery coming from the invert -- to invertor, then the loads. And we have done the short circuit and the load flow. That is correct.

MEMBER STETKAR: Do you have a model for the 12-hour --

DR. SALAMI: For two hours.

MEMBER STETKAR: But not the 12-hour station blackout coping batteries?

DR. SALAMI: For the 12-hours, during the detail, no, we don't have that.

MEMBER STETKAR: Okay. Now that you have the models built, can they be used to also evaluate DC breaker coordination?

DR. SALAMI: Correct. When we create the DC model, that would be again, the next would be populating the circuit breaker or adding the relay to the -- at this point, we don't have any relay connected to our system, because as I mention why we don't have it. The next would be adding the relay. You're adding the protective device setpoint, the type, the manufacturer and into your model, including the DC. And then --

MEMBER STETKAR: And DC, it's in many cases fuses and rather simple circuit breakers. So there is less manufacturer-specific deviations.

You've not specified those ratings or anything yet?

DR. SALAMI: Well, we have specified the breaker sizing. But as far as the type of variation, for example, as you mention, at this point, no.

MEMBER STETKAR: No? Okay. Thank you.

DR. SALAMI: Sure.

CHAIRMAN POWERS: Any other questions?

MEMBER STETKAR: No.

CHAIRMAN POWERS: Anything else you want to tell us?

MS. SLOAN: No, we're done.

DR. SALAMI: Thank you so much.

CHAIRMAN POWERS: Okay. We are going to recess until 10:45.

(Whereupon, at 10:08 a.m. off the record until 10:45 a.m.)

CHAIRMAN POWERS: Let's go back into session. What do you think about all this stuff?

MR. TESFAYE: I like it.

CHAIRMAN POWERS: Now, before you say that, remember the Subcommittee chairman is color blind, so all those color plats they have put up there have made no sense to him whatsoever.

MR. TESFAYE: I'll try something else

next time.

CHAIRMAN POWERS: Okay.

MR. TESFAYE: Thank you. I guess in this portion of this morning's presentation the staff will discuss its finding.

One thing I'd like to point out, the title here on the first slide is correct. There are no open items in this chapter. So the agenda is kind of misleading. It says SER with open items. We don't have any open items.

CHAIRMAN POWERS: It was written a long time ago. It is to give you an out. If you came in here and it said Chapter with no open items and you had one, you'd get castigated. This way you had the option.

MR. TESFAYE: All right. Thank you.

CHAIRMAN POWERS: Besides, we need to create a little excitement in Sandra's life every once in awhile.

MS. SLOAN: They make plenty of excitement in my life.

MR. TESFAYE: I'll ask Jim Steckel who's the chapter PO for Chapter 8, and Peter Kang, the technical reviewer to make this portion of the presentation.

Jim, please?

MR. STECKEL: All right. Thank you very much.

Yes, I'm Jim Steckel. This is my first time here, so I'll give you some background.

CHAIRMAN POWERS: Oh, please do, Jim.

MR. STECKEL: Not long after college I started out being hired by a consulting firm to do site characterization work. And I had done that for several years, particularly a couple of years pre-construction to the Savannah River site. But I've worked on many of the sites around the Eastern United States and the Midwest Quad Cities, Toledo Edison at Perry and several others. I've been project manager on several projects now and three-and-a-half years with the NRC.

I have a graduate degree in management. And I started out at NRC in the planning and scheduling branch, but about a year ago was able to get into this licensing branch.

CHAIRMAN POWERS: How do you like it?

MR. STECKEL: It's been quite interesting and --

CHAIRMAN POWERS: It's fun, isn't it?

MR. STECKEL: It's maddeningly

enjoyable.

CHAIRMAN POWERS: I didn't say it was easy; I said it was fun.

MR. STECKEL: I'll introduce Peter in just a moment, our technical reviewer. But here is a breakdown of our RAIs, the number of questions, I should say, of the RAIs and the number of open questions. We were able to satisfactorily close all of our questions as we've gone through.

And we do have some technical topics of interest we'd like to go through to everyone. And to do that would be our technical reviewer, Mr. Peter Kang.

MR. KANG: My name is Peter Kang. Good morning. And I have been with the Agency since 1982. Mostly spend the time at the electric engineering branch and the license renewal branch, and as well as Office of Research. And also I spend some time in the Federal Energy Regulatory Commission Office of Power Regulation and the Department of Energy working on Strategic Petroleum Reserve or bringing in a power line to middle of nowhere and the buying of equipment for pumping the oil underground facilities. And also I worked in the REA. Nobody remembers what is REA anymore, but the Rural Electrification Administration, which supply power to rural areas. And I start my career with a local utility company as a PGM representative and I work with the interconnection related work.

The first technical topics of interest is on inaccessible power cable installed in a duct bank and underground, the ones we discussed this morning. And basically in RAI we asked -- first of all, this should be a COL item. It wasn't listed as a COL item at the beginning, so we said that it has to be a COL item and also it should ask the developing site-specific testing programs for per Generic Letter 2007-01 for inaccessible power cables installed in a duct bank and underground. This Generic Letter was resulted from cable failure data from many years compilation of operation reactor experience.

And in response, the applicants agreed that this is a COL item and they added in a COL item list. And also, the applicants is to address the inspection and the testing and the monitoring programs for detection of degraded inaccessible underground power cables. And also revised the FSAR a little bit and it included a potentially acceptable testing method. It listed the partial discharge testing and the TDR, and also TDR is the time domain reflectrometry. And also power factor or anticipation factor testing and the very low frequency AC testing.

CHAIRMAN POWERS: Those are all pretty classic techniques.

MR. KANG: Yes.

CHAIRMAN POWERS: How well do they work?

MR. KANG: Excuse me?

CHAIRMAN POWERS: How well do they work? Do they really get after what you're worried about?

MR. KANG: The stuff is -- I don't know, we are worried about it and a COL, it is a site very specific area. And I know some places that they recently start -- they install the solar-powered sump pumps to pretty regularly pump the water out.

CHAIRMAN POWERS: Okay.

MR. KANG: So it is, in a certain extent, it's a problem area.

MEMBER RYAN: One of the things that troubles me is that I haven't heard anybody discuss the length between sumps and whether or not the middle stage is wet or dry. You know, in just a real practical way, groundwater is hard to control east of the Mississippi. And what we might be talking about is groundwater that's relatively close to the surface of run-in and snow melt and all these other things that have been talked about may be secondary groundwater. So, how does that work?

MR. KANG: Pretty regularly they have, you know, duct banks which collects water.

MEMBER RYAN: Yes.

MR. KANG: So, and also gravity designs certain portions when the -- where they're going to install duct bank, they sort of given slope so water can go in the lowest spot.

MEMBER RYAN: But those things are design features you never really test or prove once they're installed, do you?

MR. KANG: Well, that's correct, yes.

MEMBER RYAN: Okay. So the point is, we really don't have any proof what's staying wet and what's not. You know, a sump doesn't necessarily mean the rest of the run of wire is dry. If you pump it out continuously, where are you drying the water from? You know, unless you can demonstrate that, groundwater does funny things.

MR. JENKINS: This is Ronaldo Jenkins again. Currently now in the operating reactor arena the staff is looking at improving the inspection program.

MEMBER RYAN: Sure.

MR. JENKINS: So to have inspectors go and look at the accessible parts of the duct work to check for water, and we currently have a generic issue with industry, NEI, to come to some resolution on this issue, you know, between the NRC and the industry. So, we had a workshop earlier this year looking at different testing methods. And there's really no one method. You can combine methods, but there's not one method that will allow you to assess. And what we're talking about is the long-term degradation of the cables. Historically cables have been very reliable. For us, for the NRC, it's a question of whether or not the cable's qualified for its environment. And that's where the points you raised about how much water are you seeing, whether or not it's submerged versus wetted.

MEMBER RYAN: Wetted and then dried, wetted and then dried.

MR. JENKINS: Right.

MEMBER RYAN: That's probably --

MR. JENKINS: Probably one of the worst cases.

MEMBER RYAN: Yes.

MR. JENKINS: Yes. And so, you know, the staff is pursuing that and probably more vigorously in the operating reactor area. And we're following along with them to, you know, just make sure we're aware of it.

MEMBER RYAN: I think the point made earlier, this is really a COLA issue.

MR. JENKINS: Yes,, it is.

MEMBER RYAN: And that's, you know, down the line some, so the pressure of time is not on this activity here today.

MR. JENKINS: Right.

MEMBER RYAN: But it sure is an issue. And, I mean, you could make an argument I'm sure on some geohydrologic environments that not pumping at all is the best answer and keeping it wet. I'm going to guess that's probably true at least once.

MR. JENKINS: Yes. Well, we've also seen evidence where, you know, there's a lot of damage that has been caused by --

MEMBER RYAN: Yes, and then of course you get into, you know, which cable, when was it installed, what's the vintage and all those kind of things. It's a tough problem, I appreciate that.

MR. JENKINS: Right.

MEMBER RYAN: And I do appreciate the fact the operating folks and the staff in those areas are working vigorously on it as well.

MR. JENKINS: Yes.

MEMBER RYAN: And hopefully all that will be cleared up and readily available for you to make decisions at the COLA stage.

MR. JENKINS: Right. And for this particular application what we want to make sure is that the issue is going to be addressed by the COLA applicant, and that's the main thing.

MEMBER RYAN: My only caution is that I don't think it's fair at this stage to say that just having sumps in a design is going to solve the problem. That may or may not solve the problem based on where you are, what the geohydrologic horizon looks like. Out West, no problem at all; Everything's fine. But east of the Mississippi it can get tough.

CHAIRMAN POWERS: True of so many things.

MEMBER RYAN: Said from a guy from Albuquerque.

CHAIRMAN POWERS: Please go ahead, Peter.

MR. KANG: Next technical topics of interest is on the on-site power system. And this is a alternate feed configurations. And AREVA's presentation has it covered pretty much, why and the how it is designed to supporting on-line maintenance, and they also discussed its associated tech specs. And in our -- the ultimate configuration installed, the staff asked in RAI, how do you meet divisional independence and satisfy single failures and the risk insights? And also pointed out the tech spec provisions that allows the plants to operate for 120 days.

The response was staff received the same presentations what we seeing today. And also, we did have a meeting and sort of a meeting and that they had came in and presented how divisional independence and the single failures. They explained it and also demonstrated no single failure vulnerability existed on the various alternate-feed scenarios. And basically, in conclusion, the alternate feed configuration represents no significant change in risk. And also, the line up does not introduce any new safety concerns.

MEMBER STETKAR: Peter?

MR. KANG: Yes.

MEMBER STETKAR: A couple of questions.

MR. KANG: Yes.

MEMBER STETKAR: And I'll ask you the same question that I don't think I got an answer from AREVA. You mentioned several times in your discussion that you're satisfied that the design maintains divisional independence. I don't necessarily understand how that divisional independence is maintained if during the alternate feed configuration one division is talking to another division in terms of control signals to operate circuit breakers. And I guess I'll ask you how do you resolve that apparent inter-divisional communications? Or is that your job because that's an I&C issue and therefore it's not electrical?

MR. KANG: Okay. First of all, on the what-do-call, the divisional concept -- in other words, even though this is a four-division system, actually if you look at the really close, it is two-divisional. One and two is considered as one division and the three and four is one division, but all practical purpose for they were using as a fourth divisional concept. Like what you said, if you use alternate feed connections, it immediately return to two-divisional concept.

MEMBER STETKAR: So your determination is based on the concept that it's fundamentally a two-division plant rather than a four-division plant?

MR. KANG: Well, a two-divisional plant with a lot of excess capacity.

MEMBER STETKAR: Okay.

MR. KANG: It's 400 percent capacity.

MEMBER STETKAR: Okay.

MR. KANG: That gives -- in a way give them some comfort. In the past, we have some concerns about the emergency generator capacities.

MEMBER STETKAR: Yes.

MR. KANG: And over the years that the load has been grown to beyond -- close to the engine capacity. And so in a way it gives some comfort with that point.

MEMBER STETKAR: At some margin, if you will.

MR. KANG: Yes.

MEMBER STETKAR: But your final determination, if I understand it correctly, is that if you treat the plant as a two-division plant --

MR. KANG: Two-divisional system, yes.

MEMBER STETKAR: -- it still satisfies

the single failure criterion for a failure in one of those two divisions?

MR. KANG: Yes.

MEMBER STETKAR: Good. Thanks. That helps a bit.

The second question is, the second bullet under the response that says, "Stated there's no significant change in risk." When I asked AREVA whether they'd used the risk assessment, for example, to evaluate the 120-day LCO time limit for the diesel generator, I think said no they hadn't used the risk assessment.

MR. KANG: Okay.

MEMBER STETKAR: It's I guess interesting. Did they provide differences in the actual risk assessment results or design that had the alternate feed configuration and a design that did not have the alternate feed configuration to show what the actual difference in risk is? This, as I understand it, that bullet says there is no significant change in risk, I'm assuming, from the alternate feed configuration --

MR. KANG: Yes, sir.

MEMBER STETKAR: -- compared to a --

MR. KANG: Four-division.

MEMBER STETKAR: -- four-division?

MR. KANG: Yes, four-division. And the staff asked these questions in one of RAIs, and what is the risk increase to these configurations. But they were saying it is negligible, less than a percent. Okay? So, the way I understand is if the risk is less than a percent, you don't have to perform the evaluations.

MEMBER STETKAR: I guess --

MR. KANG: That's --

MEMBER STETKAR: -- that's. I don't want to quibble over numbers. I was curious what assumptions were built into that differential calculation in risk, because it could be very strongly influenced by the assumed fraction of time that you remain in that alternate line up configuration. If in the fact the plant does a rolling preventative maintenance outage schedule and you have one diesel out for two to four weeks a year per diesel, you could be as much as two to four months out of the year that you're actually in that particular configuration, which is a fairly large fraction of the time. I have no idea whether those are reasonable numbers.

MR. KANG: Okay.

MEMBER STETKAR: But it would be interesting to look at the basis for their assertion that the change in risk is very small.

MR. KANG: Two response. And the first one was just what I ask was under these configurations what kind of a risk was represented. But that's probably what they came in with a negligible, because one less than a percent. But in the long-term, risk, what you refer to, is the staff has not articulated. But on the other hand, we do ask that staff would express the concern. This is 120 days too long and ask for the justifications. And they did provide that this is came from the reg guide. And also, if you have a better configurations then two-divisional concept that you could have a linear or more LCO time. But, it was not really -- this number what I have here is probably just a snapshot of the configuration risk.

MR. TESFAYE: This is Getachew Tesfaye again. Would it be appropriate to discuss this when we do PRA in Chapter 19?

MEMBER STETKAR: Well, I'll certainly make a note to do that.

MR. TESFAYE: Okay.

MEMBER STETKAR: But again, in the same

vein as asking questions about the I&C, I don't like to get trapped into a box where we're examining small square bits and pieces of the design out of the context of the entire story about --

CHAIRMAN POWERS: I don't see how the question is going to change.

MEMBER STETKAR: The question won't change.

CHAIRMAN POWERS: I mean, if we move to Chapter 19 discussion, how is the question going to be any different?

MR. JENKINS: This is Ronaldo Jenkins. We asked the question primarily because we wanted to ascertain from a deterministic point of view would this alternate configuration result in a loss of its ability to withstand a single failure. Okay? And, I mean, AREVA, I think, in the phone conservation was very clear that they were not doing a risk-informed-type of analysis to make that determination of, you know, no significant risk.

So, when you're looking at this 120 days, it actually really bothers me, because when you're comparing what the staff does in risk-informed space with technical specifications and what we do from a deterministic point of view, the main difference is there's a configuration control aspect to risk-informed, you know, approvals. And which we allow the maintenance, on-line maintenance because you have configuration control, you have maintaining defense in depth, meet the regulations and you have a low risk.

So, in comparing those two, we said, okay, what they have in their design is equivalent to a spare, you know, and they're using the alternate configuration in fact to accomplish that. Now, some plants do have, like for battery systems, a totally separate spare, you know, component that they can bring in and out, do the maintenance on the equipment that's on line. And they chose not to do that. So, that's neither here nor there.

MEMBER STETKAR: I think, you know, from my perspective, what Peter said earlier helped an awful lot. In the deterministic sense of the conclusions, that if you think of the plant in a deterministic sense --

MR. JENKINS: And that's what we were --

MEMBER STETKAR: -- as basically a two-train plant --

MR. JENKINS: Right.

MEMBER STETKAR: -- and evaluate whether

it can accept the single failure criterion, I can see how that determination is made. Because the bullet is now up on the slide here about significant change in risk, I'm trying to probe whether the conclusion was at all influenced by that. And if the answer is yes it was influenced, I'm really curious about how that evaluation was performed to confirm that there's no significant change in risk.

If your evaluation wasn't based at all on any risk information or --

MR. JENKINS: It wasn't based on any risk information.

MEMBER STETKAR: -- then I don't care; they're just numbers.

MR. JENKINS: Right.

MEMBER STETKAR: Okay.

MR. JENKINS: The other aspect is that this would be something that would fall into technical specifications, you know, and that's an area that we're going to pursue, this 120 days in tech spec.

MEMBER STETKAR: In tech specs?

MR. JENKINS: Yes.

MEMBER STETKAR: Okay. Thanks.

MS. SLOAN: If I can add just one

clarification. I think we're very careful in how we use the terms "risk-informed" versus "use of risk insights." And I think I want to go back to the question you asked earlier during our presentation, because I think that's where some of this confusion is coming up. Because the way the question was phrased earlier was, is this risk-informed? And I think we're very careful to say our design basis is deterministic. But, I also want to point out that we do and have used PRA for insights. And I think that's part of the distinction we're all trying to make here.

MEMBER STETKAR: I understand that from your perspective. I'm asking the staff how much those PRA insight arguments affected their overall conclusion regarding the design, their findings in the SER.

MR. JENKINS: Not at all.

MEMBER STETKAR: Because there's kind of a gray area there.

MR. JENKINS: Right.

CHAIRMAN POWERS: I mean, I'm taking Peter at his word, that they are looking at a system that they see as a -- what did you call it -- two-train system with a lot of additional capacity.

Yes, I like that. I mean, I think that's an excellent insight.

MEMBER STETKAR: Yes, that's fine. That's fine. That's fine.

CHAIRMAN POWERS: Please go ahead.

MR. KANG: Okay. Next technical topics of interest involves Branch Technical Position 8-6. This is something to do with the adequacy of a stationed electric distribution system voltage analysis. And Dr. Salami came up here and provided, went in great detail how they performed the analysis and how the on-site power system is supported by electrical calculations.

And so, in this regard, in the RAI staff asked how to protect the safety-related equipment from degraded grid voltage conditions. And it basically requiring all the applicants requiring performing voltage analysis to determine the degraded grid setpoints. And also, in Branch Technical Position 8-6 it requires the voltage analysis you have done is validated by actual bus voltage measurements so to clarify the analysis you preformed is in fact valid.

Also, finally, in addition staff asked whether the alternate feed configurations. When you're in a different alternate feed configurations, do you need the different degraded grid setpoints rather than the ones you already done it. So, basically response said applicants is responsible for -- will preform the site-specific analysis to determine the site-specific degraded grid setpoints based on off-site power system, whether hanging in there, are connected. And also, those setpoints value is in the tech spec. So, and also applicants indicated, stated that they will conduct the verification test during planned initial testing, under initial plan testing program. This is Chapter 14.2 sections. And staff has verified that this test No. 161 does verify the measures, the voltages of -- so verifies it.

And also, the last question, whether you have a different configurations, whether do you really need the different setup of degraded setpoints. The answer was no. And their evaluation has shown you don't need the change every time you go to different configurations.

CHAIRMAN POWERS: I get the impression that the applicant here has created this modeling capability to say yes this electrical system can in fact be constructed, get some idea of what the components in the system will look like.

MR. KANG: Yes.

CHAIRMAN POWERS: And they come up with a system for analysis that it says that indeed the COL applicant can in fact do what he will be asked to do.

MR. KANG: That's right. Each COL applicant has to have calculation, what we used to call the case base. In other words, the system representations which they have, or they are going to have. And based on that, they performed the load for analysis, show circuit calculations and all that calculations to verify their base is a real value of the case. So, in a fact, that would be used to setting for the degraded grid setpoints, as well as they could use this program to make plan modifications. If you want to add another MCC --

CHAIRMAN POWERS: Configure sump pumps for --

MR. KANG: Sump pump.

CHAIRMAN POWERS: -- Brian happy. You're very hard to please. Did you know that?

MR. GARDES: All depends on the --

MR. KANG: In the stuff asked, our reg guide requires to perform this various calculation.

So in staff RAI, we asked provide some summary assumptions with what you done, assumptions and a summary of each calculations. And they did provided in the written form, as well as we had a staff met -- what do you call this, audit, performed audit on that, spend a day. And they're looking through those --

CHAIRMAN POWERS: Your staff does not have an independent calculational capability for these things?

MR. KANG: No. No, we haven't gone that far yet.

CHAIRMAN POWERS: I don't know that you need to. I mean, most of this stuff is licensee land. But I was just curious.

MR. KANG: But, you know, the verification says, you know, well we measured this analysis versus these measurements. And they came out within --

CHAIRMAN POWERS: The proof is the pudding here, yes.

MR. KANG: It came in from a long way since 1980s. We used to use a pencil calculations and we are happy with that.

CHAIRMAN POWERS: I guess the proof is

the VOM, or something like that, right?

MR. KANG: Anymore questions on this?

(No audible response.)

MR. KANG: Okay. Next technical topics of interest is on sizing of the station blackout diesel generators. And in RAI, staff asked -- we brought -- the SECY-91-078 recommends that the new reactor meets EPRI utility requirement document recommendations. And that recommend had the large combustion turbine is used as a AAC power source and it should be capable of powering at least one complete set of load to cause shutdown. Okay. So, I said, hey, this is what SECY says. And we asked this question and in response applicants stated they're installing two 3,900 kW station blackout diesels who would be used AAC power source for U.S. EPR design. And they clarified a cold shutdown is not required under --

CHAIRMAN POWERS: That's the one I don't understand. I don't understand --

MR. KANG: A cold shutdown is not required on the current NCFF of 56 degree. And so the U.S. EPR plan is only designed for to go hot shutdown and the standby during the coping period.

CHAIRMAN POWERS: Well, if I go to

appendix R, and I think cold shutdown is required there, isn't it?

MR. KANG: Well, we did look at the appendix R review as well as the reason they ask for large AAC power source at the combustion turbine. This is U.S. ABWR. They were putting 20 megawatt. In other words, essentially what they doing is they are replacing all non-class 1 be able to power non-class 1E system. But in this case is considering for emergency diesel generators, as well as a off-site power system. And the current regulation is on the 10 C.F.R. 53. That's what they want to stick to. So, that's where we resolved the issues and the staff had no further questions.

MR. JENKINS: And to answer your question, that's correct. Appendix R requires that the equipment be -- bring the plant to cold shutdown. That's my understanding.

CHAIRMAN POWERS: One of the ways to get into a station blackout is to have a fire.

MR. JENKINS: Yes, there's a couple ways to get there.

CHAIRMAN POWERS: Yes. So I don't quite understand that one.

Sandra, can you explain to us a little

bit?

MS. SLOAN: I can explain that the design basis of the plant is consistent with all operating plants, which is consistent with the station blackout rule, which explicitly talks about powering the plant down to hot shutdown loads. And I'm going to look at our technical staff and see if they want to add more.

MR. GARDES: I'm going to try do the limits of my knowledge, but I believe appendix R, you know, post-fire safe shutdown you can still credit the emergency diesel generators and that you will have, you know, a divisional train protected. But in station blackout beyond design basis, you can't credit the EDG. So for sure in appendix R with the EDG capacity capability, you can go to cold shutdown --

CHAIRMAN POWERS: You are right.

MR. GARDES: Okay.

CHAIRMAN POWERS: You are 100 percent right. There's a protected train in appendix R, and here there is not. That's the difference.

MR. GARDES: Right.

CHAIRMAN POWERS: Now, the fact that we can get into a station blackout -- a fire. Okay.

Good enough. I understand now. Thank you.

MR. GARDES: You're welcome.

MEMBER STETKAR: Peter?

MR. KANG: Yes?

MEMBER STETKAR: The last couple of slides are sort of close-out slides, right? Let me bring you back to the station blackout diesels. The station blackout diesels are started automatically, but all loads are placed on those diesels manually, is that correct?

MR. KANG: Manually, yes, within 10 minutes. Yes.

MEMBER STETKAR: Now, that's the question that I had. Within 10 minutes --

MR. KANG: Right.

MEMBER STETKAR: -- what type of evaluation was done to show that indeed those diesels can be connected to all of the required buses and the loads can be started and connected within 10 minutes?

MR. KANG: Okay. That is the ITAAC. When during ITAAC time they were supposed to verify this stuff, within 10 minutes that they can start and be able to connect the load.

MEMBER STETKAR: I guess my curiosity

is, we have a lot of discussions in the digital instrumentation and control system area with determining whether the design for diverse actuation systems need to be automatic or can they be manual. In other words, can an operator manually start equipment from the diverse actuation panel or must those start signals be automatic considering, you know, a common-cause failure of software or something over in the digital I&C platforms?

I view this as kind of an analogous situation where we have a station blackout. We've had a loss of off-site power, some failure of the EDGs, and now the station blackout diesels must provide power within some required time frame. There are -- I don't want to use the term "requirements," because they're not requirements. There is Interim Staff Guidance and a NUREG, 1852, that lays out a methodology for evaluating whether or not manual actions are acceptable. And that methodology looks at the available time window and the amount of time that's actually required to perform the actions with some margin.

MR. KANG: Okay.

MEMBER STETKAR: And those guidelines are used fairly extensively in evaluating diverse actuation systems. I didn't any discussion of that type of analysis for this design. And if you say, well, it's up to the COL applicant to perform that evaluation, suppose he fails? That's a design issue.

MR. KANG: I did check with the reactor systems branch folks who are reviewing these issues. And I think very recently they did have an audit on this how long the EPR plant can last without the electrical powers. Is that what time margins do they have? I think they were looking almost over an hour.

MEMBER STETKAR: Okay. I'm not arguing with the -- I have to be careful in my words here. I'm not arguing with technical. I'm arguing with the justification that says no analysis is required because it is asserted that the equipment can be repowered within 10 minutes. Ten minutes is not a long time frame if you're talking about closing a couple of sets of series circuit breakers and re-energizing equipment under conditions that you've never seen before.

MR. KANG: Yes. And one of SBO rule requires a training and develop of procedures. And they were supposed to -- each COL applicants are supposed to go practice or procedures to periodically perform this exercise.

MEMBER STETKAR: I guess I feel uncomfortable with someone just stating, well, it shall be done within 10 minutes because we're going to train the operators to do it within 10 minutes without performing any type of reasonable analysis to at least try to demonstrate that, especially when we as an agency in other areas; in particular the digital I&C diverse actuation system area, are spending a lot of effort requiring applicants to demonstrate that capability, to justify whether something needs to be automatically initiated or can it be manually initiated. And here we seem to be just taking an assertion that it can be done in 10 minutes and we're going to train the operators to do that and accepting it.

MR. KANG: Well, in FSAR they did not provide the scenarios and how the sequence was to be done. So, we have reviewed it and I ran by the active systems and seems like it is a doable. And also in the ITAAC, they are demonstrating it can be done.

MEMBER STETKAR: Okay. I guess I can't say anything more. I just feel uncomfortable. A) I feel uncomfortable with a 10-minute time frame for all of those actions, given a station blackout and the confusion factors that are going to be inside the main control room when you have something that you never expected would ever occur, simultaneous failure of all of your emergency diesel generators after a loss or off-site power that never happens. So the absolute value is one concern.

MR. KANG: But and also --

MEMBER STETKAR: But the larger concern is that we apparently are accepting that value prima facie without any supporting analyses on the part of the applicant to confirm that indeed they looked at human-factors-type things and actual realistic time frames with the types of margins that we're requiring for other features of the design approval process. You know, that's just a statement.

MR. KANG: Yes.

MEMBER STETKAR: I don't think we need to discuss it anymore. I understand what you've said.

MR. KANG: Yes, staff findings. And this is --

CHAIRMAN POWERS: Please go ahead, Peter.

MR. KANG: And the staff findings and the U.S. EPR FSAR provides, first of all, sufficient informations about off-site power system inter-relationship among nuclear utility, nuclear unit and the utility switchyard, and the interconnection grid -- COL applicants.

And next bullet is sufficient information about the on-site power system to mitigate the design basis events and given a loss of off-site power and a single failure in on-site power system.

And the last one is necessary analysis has been performed to determine capability to withstand and recover from SBO event of specified eight-hour durations.

CHAIRMAN POWERS: Do we have any other questions for Mr. Kang?

(No audible response.)

CHAIRMAN POWERS: I see no more questions.

MR. TESFAYE: That's all we have for Chapter 8.

CHAIRMAN POWERS: Do you have a question?

MEMBER STETKAR: I do. Does it surprise

you? You're shocked.

CHAIRMAN POWERS: Well, my question is whether it's pertinent to the discussion.

MEMBER STETKAR: Yes.

CHAIRMAN POWERS: Oh, okay.

MEMBER STETKAR: In my feeble mind it is.

For other plant designs that come up before us, there is this concept of RTNSS, regulatory treatment of non-safety systems, for systems that are nominally not safety-related, but important to risk, I guess. We haven't really understood quite what the definition of a RTNSS requirement is.

And I guess my question is, does that category of require apply in the EPR design? In other words, are you looking at tech spec-related issues for safety equipment and RTNSS requirements, additional regulatory scrutiny for non-safety equipment, but equipment that's still relatively important to overall plant risk?

MR. TESFAYE: No, RTNSS is not considered. The EPR is not a passive system.

Joe, maybe you want to add something to this?

MR. COLACCINO: Yes, hi. My name is Joe --

MEMBER STETKAR: That's only for passive plants?

MR. COLACCINO: Yes. My name is Joe Colaccino. I'm the chief of the EPR Projects Branch. The RTNSS system, that was first documented in the review of the AP600. And you also see that in the AP1000. It's carried over into the ESBWR. It is strictly for passive safety system plants that are under review with design certification by the NRC. What you have before you in the EPR is an active safety system plant. And so there isn't a question of -- a lot of the systems that are in -- that are active safety systems plants are not safety-related in those other designs. And so, the discussions; and there are other people in this room who could probably expand on it, but I'll just keep it really succinct, it's that like, okay, so these systems are not active safety systems, but what are other considerations that could look at to have some treatment of these systems in regulatory space? And so regulatory treatment of non-safety-related systems.

There's a really good write-up in

Chapter 20, I believe it is, of NUREG-1793. I think that's the AP1000. That's the Rev 15 version. I believe it's Chapter 20. I'm pulling that out of memory right now. But the first several pages of that gives you a discussion of the background associated with RTNSS.

CHAIRMAN POWERS: I have to admit I did not know that RTNSS was strictly for passive.

MR. COLACCINO: Either did I.

CHAIRMAN POWERS: We've been struggling with this --

MR. COLACCINO: Dr. Powers, I'm going to take you at your word, sir.

CHAIRMAN POWERS: What's that reference? There's a really good write-up?

MR. COLACCINO: It's the --

CHAIRMAN POWERS: Seventeen-ninety-three.

MR. COLACCINO: Yes, it's the AP1000 FSAR. And maybe Hanh Phan here from the PRA group maybe give you a little more, if you want it. But that's basically what I've done is the Reader's Digest abridged version for project managers.

CHAIRMAN POWERS: They keep giving us --

MEMBER STETKAR: If indeed in terms of

the Agency RTNSS applies strictly to passive design; I don't understand why that's the case, but if that's the case, then I understand why it doesn't apply here. I was going to ask, you know, in particular with respect to the station blackout diesels, because in the passive designs the station blackout diesels would be considered a RTNSS piece of equipment. But their analogous equivalent are.

MR. COLACCINO: I took the reference from memory. I'm sure Derek can -- I believe it's NUREG-1792 or 1793. We'll get you covered. We'll get you that reference.

CHAIRMAN POWERS: That would be useful. That may be helpful in a lot of --

MR. COLACCINO: Yes. And I know because I was the project manager that took that and put that in there, and I thought that this was a good place. And it comes from the AP600, and it's something that we needed to preserve as background. And so it goes through the regulatory history of how we got to that point.

CHAIRMAN POWERS: Very nice. That would be good. Thank you.

MEMBER STETKAR: Now I don't have any more questions. Was it relevant?

CHAIRMAN POWERS: It was extremely useful. Maybe not relevant to EPR, but there are other contexts that this will help.

MEMBER STETKAR: So you're happy?

CHAIRMAN POWERS: I didn't say that.

MEMBER STETKAR: Okay.

CHAIRMAN POWERS: We're done?

MR. TESFAYE: Yes, sir.

CHAIRMAN POWERS: So we'll move onto site characteristics after a midday repast. And after means at 1:30.

(Whereupon, the hearing was recessed at 11:34 a.m. to reconvene at 1:30 p.m. this same day.)

A-F-T-E-R-N-O-O-N S-E-S-S-I-O-N

1:30 p.m.

CHAIRMAN POWERS: Let's come back into session. We're going to try to avoid the heated controversies that we had earlier today, Sandra, and begin to discuss site characteristics.

Do you have any introductory comments to make on this?

MR. TESFAYE: No, I don't.

CHAIRMAN POWERS: You're going to let this fight out on hit's own, huh?

MR. TESFAYE: Yes.

CHAIRMAN POWERS: Okay. Sandra, let's talk about sites.

MS. SLOAN: Okay. Well, as with the morning --

CHAIRMAN POWERS: In Finland.

MS. SLOAN: What's that? Oh, no.

CHAIRMAN POWERS: The coast of France?

MS. SLOAN: Not that it's not a nice site. It's a perfect site. Cold water and hard rock -- site to build a nuclear power plant.

CHAIRMAN POWERS: Persistent sea breezes, things like that, and not far from fairly good Italian food, right?

MS. SLOAN: Sure. Okay. So just like in the morning, what we thought we'd do for tier 2, Chapter 2 is in the AREVA presentation give you a summary level overview of the organization of Chapter 2 and the material in Chapter 2. And I also wanted to mention, as with the morning session, we have participants on the phone line right now from a couple of remote AREVA locations. So there may be times when the presenters will call on the supporting staff at the other locations.

And so, with that, I asked this time for Todd and Ted to at the very beginning give you a brief introduction of who they are. And then Todd will start the actual presentation.

CHAIRMAN POWERS: Good. Good. Welcome to the Committee.

MR. OSWALD: All right. Ready to go?

CHAIRMAN POWERS: Yes.

MR. OSWALD: Okay. My name is Todd Oswald. I'm currently a technical consultant in the civil structural group within AREVA and I have been responsible over the last five years for all of the civil structural activities that we've had going on on the U.S. EPR license application.

I've been around the nuclear around 29

years. Started off in the nuclear Navy out of college. Came out, worked at Maguire Nuclear Station with Duke Energy and doing modifications and doing performance testing.

CHAIRMAN POWERS: So you're a relative newcomer here?

MR. OSWALD: Yes, a relative newcomer, like most of us. Yes, probably the youngest.

I did my undergraduate work and master's degree from the University of South Carolina, again in structural engineering. And after I came out of the Navy, I mentioned I went to Maguire Nuclear Station. And then after I left Maguire Nuclear Station, which was stayed there about seven years, worked for the last 17 years in a design engineering organization. Started off with the ABB System 80+ certification. Lot of familiar faces around here from that work. And then like I said, for the last five years I've been the structural lead on the U.S. EPR.

I'll be presented Chapter 2 with the exception of Section 2.3, which my colleague here, Mr. Ted Messier -- he'll present Section 2.3. And I'll let Ted introduce himself.

MR. MESSIER: Good afternoon. I'm Ted

Messier. My title is principal scientist. In the Radiation and Nuclear Radiation Engineering Group in Marlboro, Massachusetts. I've worked of bits and pieces of the design certification application for COL applications and two applications for the uranium enrichment plants. And I also do work supporting the existing operating fleet here in the U.S. I've been in the industry 20 years this year.

Educational background, I have a bachelor or science degree in meteorology from the University of Lowell in Massachusetts and a master's degree in meteorology from The Pennsylvania State University.

CHAIRMAN POWERS: The Pennsylvania State University. Okay.

MR. MESSIER: Otherwise known as Penn State.

Mr. Oswald, you have the floor, sir.

MR. OSWALD: Okay. If you'll go to the next slide here, let's get started.

Chapter 2. Chapter 2 introduces the description of the all the design parameters used in the U.S. EPR of the FSAR. And the requirements placed on the COL applicants to characterize their site and reconcile with those parameters that are in

Chapter 2 in the FSAR.

The following areas, as you can see on the screen, are included in Chapter 2: Geography and demography; nearby industrial transportation and military facilities; meteorology, which Mr. Messier here will address; hydrologic engineering; and geology, seismology and geotechnical engineering.

Okay. Chapter 2 in general. The U.S. EPR design is based on a set of what we feel are conservatively established parameters which represent more demanding site conditions than you would probably see at any give site. Again, this is Certified Design. Table 2.1-1 is the best summary of all these requirements that are put on the COL applicant. And it's got all of the site parameters used in the U.S. EPR standard design.

Any COL applicant that references the design, will make a comparison of the site-specific characteristics with the parameters that are listed in table 2.1. Of course, if they fall within the parameters of 2.1-1, it's considered bounding. If they don't, the data has to be collated and confirmed that the U.S. EPR design parameters or the design itself will envelope the site-specific characteristics.

Okay. Section 2.1, geography and demography. And this section requires the COL applicant to define and describe the site, describe the exclusion area authority in control and describe the population distribution.

And in Section 2.1.1., the site location and description, there's a requirement to specify the locations in terms of the latitude, the longitude, using universal transfer mercator coordinates and the political subdivisions. Also, a map is required of the area with relevant features such as plant property lines, site and exclusion area boundaries, the EAB, location and orientation of --

CHAIRMAN POWERS: Does the applicant have to own the exclusion area?

MR. OSWALD: Does the applicant have to own the exclusion area?

CHAIRMAN POWERS: Yes.

MR. OSWALD: That is not explicitly addressed in the U.S. EPR FSAR. There is no specific requirement currently in there.

Want to take a note on that one and we can pull the string on that. Does the applicant have to own the exclusion area?

MS. SLOAN: Sure.

MR. OSWALD: Then in Section 2.1.2 the exclusion area authority control requires the applicant to define the authority and activities of the exclusion area. So, they've got to identify who owns it, who's in control there and all the activities that are going on there.

Section 2.1.3, population distribution. That requires the applicant to describe the population within the site vicinity.

Before we go to 2.2, are there any questions on what's required in 2.1?

CHAIRMAN POWERS: You do not specifically call out special needs facilities and things like that?

MR. OSWALD: No, we do not in the FSAR. Are you talking about local fire department support or --

CHAIRMAN POWERS: Hospitals, old age homes, invalid.

MR. OSWALD: Oh, you're referring to evacuation zones and requirements?

CHAIRMAN POWERS: If there are any complications in the evacuation plan for the site.

MR. OSWALD: No. Again, this is the

Certified Design FSAR. That's all pretty much the burden of the COL application to identify all of that.

CHAIRMAN POWERS: Surprising that you don't alert them to the fact. I'm sure he knows.

MR. OSWALD: Yes, right. We point them to the reg points, point them appropriate requirements.

CHAIRMAN POWERS: Continue, please.

MR. OSWALD: But we leave it up to the COL applicant.

CHAIRMAN POWERS: COL applicants have to know what they're doing?

MR. OSWALD: Yes. Yes. We try and make sure they're going down the right path, but we don't tie their hands or anything.

Okay. Section 2.2, nearby industrial transportation and military facilities. Again, the U.S. EPR, I'm sure you are somewhat familiar with the design of this structure. It is a very robust design when considering any potential external hazards. And again, this robust design, the reason we make that statement is because we have -- it's primarily attributed to an external shield wall which we have around a significant portion of the plant, 1.8 meters of six-feet thick reinforced concrete. And also, we have four divisions and they are all separated a distance around the plant. So therefore, we feel like this is a very robust design when you're considering external hazards.

Section 2.2, again, the burden is on the applicant to identify all of these items.

CHAIRMAN POWERS: Do you alert him to consider not just what's there, but what's going to be there?

MR. OSWALD: Again, we don't talk about future items or future development activities around there in the standard design.

CHAIRMAN POWERS: Yes, when we do the early site permits and whatnot we of course are required to interrogate local officials about what changes are anticipated in the future as far as transportation, military facilities, flight paths, things like that. And oftentimes we find that those officials are aware of changes anticipated in the future.

MR. OSWALD: Planning commissions know what's coming. We can take a look. I don't think there's any explicit reference to future development in the Certified Design.

CHAIRMAN POWERS: Well, the plant's going to last for at least 40 and maybe 60 to 80 years.

MS. SLOAN: I think if anything it would be in their environmental report or in their COLA application.

CHAIRMAN POWERS: It's required in their application. I mean, right now you're just quoting the standard content and the design. Within this particular subsection I'm just wondering how far you go. I mean, clearly you're just alerting the applicant to these things and setting the ground work for what your design basis is. And I'm just wondering how far you go. That's all I'm trying to find out.

MR. OSWALD: I don't recall any wording in 2.2 requiring them to look at future projected development around the site.

MS. SLOAN: (Off microphone.)

MR. OSWALD: Okay. That will be in 2.2.

Okay. Let's see where we are. Section 2.2.1, location and routes. The applicant is required to describe the location and the routes associated with the facilities, the industrial transportation and military facilities.

2.2.2, descriptions. The COL applicant is required to describe the facilities' primary function and the nature of the hazard imposed by these facilities close to the plant.

Section 2.2.3, evaluation of potential accidents. The applicant will provide an evaluation of the potential for an accident associated with the facilities and the consequences. And we do recognize that the applicant may use a probabilistic approach on those hazards.

Any questions thus far through 2.2? Any more?

(No audible response.)

MS. SLOAN: And I just doubled checked, Todd. There's nothing in 2.2 that specifically directs the COL applicant to consider future plans. It just says simply the COL applicant will address nearby industrial, blah, blah, blah facilities. It's pretty general.

CHAIRMAN POWERS: You're not obligated to do anything. I just wondered how far you went.

MR. OSWALD: Okay. If there are no more questions on 2.2, I'll reintroduce you to Mr. Ted Messier here. He's going to talk about Section 2.3 with the meteorology.

MR. MESSIER: Now we get to see just how good my new bifocals are.

CHAIRMAN POWERS: If you're new to them, Ted, you're in trouble.

MR. MESSIER: So Section 2.3, meteorology. As I'm sure you've heard, the EPR design is based on meteorological parameters such as extreme air temperatures, precipitation rates and so on, which are provided in table 2.1-1, which is the site design envelope parameter list.

CHAIRMAN POWERS: Yes, let's get right to the question that is going to emerge sooner or later here.

MR. MESSIER: Okay.

CHAIRMAN POWERS: You're going to build a plant that's going to last for 60 years. It's going to take you five to seven years to build this plant. So we're talking about a significant portion of a century here.

MR. MESSIER: Yes.

CHAIRMAN POWERS: You're going to specify the meteorological extremes based on historical evidence. What basis does one have for arguing that historical meteorological data is applicable for the next century?

MR. MESSIER: That's a very good question. I'm not so sure I have a good answer for it.

If you look at global circulation models that are being used now to predict climate change, the results are fairly general in nature, you know, on a fairly large scale. And as you try to reduce them to a smaller and smaller scale, say regional, the error associated with doing that increases. And I think that's fairly well spelled out in IPCC reports and I think the U.S. Government report on climate change.

So, you can make some estimates of how you think climate is going to change here over time. But what it boils down to is what we have for hard data is the historical record. So that's more or less got to be our starting point. It's the data we have that's been observed. We know it to be true. It's a ground truth, if you will, for future analysis.

CHAIRMAN POWERS: Suppose I say global climate change, don't care? I just look at the historical data.

MR. MESSIER: Yes.

CHAIRMAN POWERS: And I look at the

historical data. Suppose I was going to build a plant maybe on the Atlantic Coast of the United States, maybe in Maryland some place. Maybe. And I looked at that data and I would find that there are cycles in hurricane frequency, Atlantic storms and whatnot.

MR. MESSIER: Yes.

CHAIRMAN POWERS: And I'd find maybe that there are two cycles and that we've been in a period of relative tranquility and moving into a period of heightened activity, or certainly over the course of 75 years I'm going to enter into a period of heightened activity. Shouldn't I take that into account when I set my parameters?

MR. MESSIER: Well, first of all, there have been heightened periods of hurricane activity I think as recent as the '40s and '50s, if I'm not mistaken. And that information has been captured and put into things such as the ASCE-7 standard on design. And we use that information from that standard for non-tornado wind speed information for designing safety-related structures and non-safety-related structures.

So with regard to hurricane winds and impact on plants, that has been taken into account.

You know, it is part of the standard review plan, NUREG-0800.

CHAIRMAN POWERS: That I'm not aware of. There are hurricane cycles in the standard review plan?

MR. MESSIER: Not cycles, but the impact of hurricanes is addressed.

MEMBER RYAN: And one maybe related question is, have you done any kind of recurrence interval estimates on the parameter values you have selected?

MR. MESSIER: In terms of?

MEMBER RYAN: How likely they are in a hundred years, or some kind of recurrence-sort of parameter that would tell us what's the probability that that value will be met or exceeded.

MR. MESSIER: Most of the site parameters for meteorology for design, except for tornadoes and snow load which came from NRC Guidance, Interim Staff Guidance 7 for the snow load and Reg Guide 1.76 for tornadoes, most of it has come from the EPRI Advanced Light Water Reactor Utility Requirements.

CHAIRMAN POWERS: I'm operating from memory, I'll have to assure, but I do not recall them going into any detail about talking about what I know about our hurricane frequencies on the East Coast.

MR. MESSIER: Nor do I. I'm just stating the provenance of the information.

We have not been required to look at say 100-year return period values of precipitation, extreme precipitation rates or extreme temperatures. We're using the so-called zero percent exceedance maximum temperature values for our design, which is 115 degrees dry fall and 80 degrees coincident wet fall, which seems to bound most of the United States potential site locations.

MEMBER RYAN: And I appreciate and accept that, but I'm trying to get a different way to get at Powers' question, which is if you had some idea of a recurrence interval of some value, you know, you could sort of address the question, well, you know, given what we know, and the history you mentioned, the likelihood of exceeding this value in 100 years or 300 years is X.

MR. MESSIER: Okay.

MEMBER RYAN: There a way, at least for me, to think about his question in a slightly different way.

MR. MESSIER: For the snow load and for the non-tornado wind speed, both of those do take into account 100-year return period values of snowfall, snow depth, and wind speed.

MEMBER RYAN: Okay.

MR. MESSIER: So in that regard, in terms of structural strength, that has been included.

MEMBER RYAN: How so? How has it been addressed?

MR. MESSIER: ASCE-7, the value we use I believe is for a 50-year recurrence value period. But then there's an importance factor you can use to bump that up to a 100-year value. And that's what we've provided.

MEMBER RYAN: Okay.

MR. MESSIER: Interim Staff Guidance goes into detail on 100-year return period snow depth and snowfall.

MEMBER RYAN: Thank you.

MR. MESSIER: You're welcome, sir.

MEMBER STETKAR: Ted, and you're careful about excluding tornadoes. I didn't look very far ahead in your slides. Were you going to talk separately about tornadoes or not? Is this the appropriate time to ask about --

MR. MESSIER: If you'd like to ask a question, you might as well.

MEMBER STETKAR: Well, then I will. In the same vein as Mike mentioned about recurrence intervals, if I look at the design tornado wind speed loadings, they're in the 180 to 200-plus mile per hour range, which is somewhere in the F3, F4 Fugita intensity range. And I understand the basis for that. I guess my curiosity is if you look at return intervals, which obviously vary quite dramatically depending on where you are in the United States; I just pulled up some data for a place that actually isn't all that infrequent for tornadoes, recurrence intervals for F3, F4 tornadoes striking something roughly the size of a nuclear power plant profile are on the order of somewhere around 10 to the minus five or a little higher per year. So once in roughly 100,000 years. It can be a little bit higher. This happens to kind of a moderate activity site. It was just one I could pull up for reference here quickly.

I guess my question is not so much in terms of the design, because I understand the criteria you're using for the design. My curiosity is that the risk assessment claims to have accounted for all internal and all external events. And they published total core damage frequencies on the order of three times ten to the minus eight per year, or roughly a factor of 1,000 times lower frequency than the site being hit by a tornado that exceeds the sit design characteristics.

Do you have any idea how the risk assessment folks factored the design criteria or recurrence intervals for these very extreme events into their analyses?

MR. MESSIER: No, sir, I'm sorry I don't.

MEMBER STETKAR: I mean, I understand what you've designed the buildings to. The question is, you know, how does that actually affect the overall risk of the site?

MS. SLOAN: I think we're going to have to take the question, because I think it's really one for our PRA folks.

MEMBER STETKAR: I just wanted to make sure I understood the basis for the actual wind loading design and things like that. And since the question about recurrence intervals came up, I thought I'd raise that frequency argument also.

MR. MESSIER: Sure.

MEMBER STETKAR: And you're right, Sandra, it's more a question for the risk assessment folks than the design. I understand the criteria that you're using.

CHAIRMAN POWERS: That's the strategy we'll use. We'll put everything on the risk --

MEMBER STETKAR: Well, it is. As I mentioned this morning, you kind of like to raise some of these issues in the context --

CHAIRMAN POWERS: That they arise.

MEMBER STETKAR: -- that they arise, rather than waiting for the risk assessment. Because many times when you look at the risk assessment, you get bogged down into a lot of other things,

CHAIRMAN POWERS: Stuff that Stetkar brings up.

MEMBER STETKAR: Not me. Okay. Thanks.

MR. MESSIER: I'll just continue with this slide. Once again, if the COL applicant that references the design comes up with values that are outside of the range, they will have to demonstrate the acceptability of the site-specific open sections of their application.

Section 2.3 is broken up into five subsections. The first is regional climatology. And this will include such things as air quality, severe weather information, meteorological data used in the evaluation of the ultimate heat sink. This is all provide by the COL applicant, as these are site-specific characteristics.

.2 subsection is local meteorology. And this would be the bread and butter of all meteorologists, the statistics of temperature, precipitation, snowfall and so on, again all site-specific characteristics.

.3 subsection, the meteorological measurement program. Again, site-specific. You will talk about the system accuracies and so on that are required, data reduction, data recovery goals and so on and so forth.

A little more interesting, .4, which is the short-term atmospheric dispersion estimate for accidental releases. We have looked at these. We have come up with values that we consider to be representative of potential future sites in the U.S. and to calculate the postulated accidental releases, the consequences thereof.

CHAIRMAN POWERS: One of the problems we

always encounter in looking at dispersion around a plant is local building wake effects. Do you provide a description of those wake effects?

MR. MESSIER: For the accidental releases we did not take credit for building wake effects. So we know that that it's there. The models do have a component that you can turn on or off. But for the accident analysis we did not take credit for building wake effects that may prove --

CHAIRMAN POWERS: You haven't ever put this plant design into a wind tunnel and looked at things?

MR. MESSIER: Not to my knowledge, no.

CHAIRMAN POWERS: Actually, I know it has been.

MR. MESSIER: I know for a control room habitability analysis, we used the ARCON96 code, which was developed by Van Ramsdell. And that does include a lot of work I believe he has done in the past with building structures in wind tunnels and so forth.

CHAIRMAN POWERS: Yes, it just has a model of wake effects, and that model is probably the best approximation running around right now. It's certainly better than the Campe model.

MR. MESSIER: Yes.

CHAIRMAN POWERS: But, you know, it would be neat to actually put the building into a wind tunnel and see what things look like around it, I mean, in the modeling and things like that. But you don't provide that?

MR. MESSIER: Unfortunately, no.

CHAIRMAN POWERS: Okay.

MR. MESSIER: Okay. Once again, the COL applicant would come up with their site-specific accident chi over Q values to see whether they are bounded by those provided in the EPR design. If not, they would have to demonstrate that the radiological consequences still meet the applicable dose limits.

And in subsection 5, which is the long-term annual average atmospheric dispersion estimates for routine releases from the plant, we have developed a value we feel to be representative of many potential future locations. COL applicant must come up with their own site-specific values once again, see whether they have bounded or not. If not, they must do an evaluation to show that they still meet the applicable dose limits.

Are there any other questions on Section

2.3?

(No audible response.)

MR. MESSIER: Hearing none, I will turn you back over to Mr. Oswald.

CHAIRMAN POWERS: One of the questions, do you ask that the licensee maintain a meteorological station on the site after the building is constructed?

MR. MESSIER: Yes, sir.

CHAIRMAN POWERS: That's fine.

MR. OSWALD: Okay.

CHAIRMAN POWERS: Hydrologic.

MR. OSWALD: Hydrologic, Section 2.4. And Section 2.4 describes the hydrologic parameters considered for the U.S. EPR, and again, back up to the COL applicant again, to reconcile with these parameters.

CHAIRMAN POWERS: Poor COL.

MR. OSWALD: Yes.

CHAIRMAN POWERS: Never have I seen a customer abused so badly here.

MR. OSWALD: Okay. In our parameters on the U.S. EPR, of course we consider all the groundwater, winter precipitations, snow, sleet, ice, rainfall, surface flooding. And again, these values are provided in table 2.1-1 for a quick summary. Take a quick look at what our parameters are considered in the design.

Section 2.4.1, hydrologic characteristics. In this section the applicant is required to describe the site-specific characteristics related to the hydrologic conditions at the site.

Section 2.4.2, the floods. The applicant is required to investigate and describe the site-specific flood history, the flood design features and the effects of local precipitation on the design.

MEMBER STETKAR: Todd, on hydrologic, I notice the specification is that the maximum groundwater elevation is 3.3 feet below grade, roughly a meter below.

MR. OSWALD: A meter below.

MEMBER STETKAR: With some relevance to the discussion this morning regarding underground cable ducts, do you have any information what the bottom elevation of any of the building structures are below grade, or the elevations of those cable ducts below grade? I didn't have a chance to go look at it and I don't even know whether the information is available, so I'm kind of asking --

MR. OSWALD: Right. Most of the duct work, the cable ducts of course would be up near the top.

MEMBER STETKAR: But that's only a meter below grade.

MR. OSWALD: Yes, that's right.

MEMBER STETKAR: They're typically much deeper than a meter below grade.

MR. OSWALD: That's correct.

MEMBER STETKAR: They're two to three, at least.

MR. OSWALD: One of the obvious ones on this design is the emergency power generation building, the diesel buildings. That foundation is about six-feet deep. And then duct work will come out the bottom of that building, because it's deep enough for external hazards, missiles, tornado missiles, etcetera, to keep from damaging them and run over. So, I would say they're going to be six to ten feet below grade. So that groundwater table --

MEMBER STETKAR: Will be impacted.

MR. OSWALD: -- will be impacted.

MEMBER RYAN: And one of the things it's

a fairly large construction. And I guess with the near field of that large construction I'm going to pretty much bet any money I've got that it's not going to be the same after it is before.

MR. OSWALD: Right.

MEMBER RYAN: So, how do you deal with that at this stage? I know the COL has the responsibility to address that question ultimately, but --

CHAIRMAN POWERS: They need a substantial amount of information from the designer to do it.

MEMBER RYAN: Yes.

MR. OSWALD: Right. And those ducts, we have criteria in the Certified Design for designing the ducts. Well, the design code, ACI, etcetera, and the requirements --

CHAIRMAN POWERS: But Mike's asking a little different question, I think. He's saying, okay, we have a site; it sits here. We have a hydrologic model for that site. As soon as you put that plant on that site, that hydrologic model is no good anymore.

MEMBER RYAN: It's no good certainly within the proximity of the buildings and structures. And you could probably make an argument that it's okay at some distance. What distance it is is depending upon all the key features at the site. You could even seen reversals of flow.

MR. OSWALD: Right.

MEMBER RYAN: So, I'm struggling a little bit with how the preexisting geohydrology, at least for the near field to the building is valid and how you address that.

MR. OSWALD: Well, of course the COL applicant --

MEMBER RYAN: Yes.

MR. OSWALD: -- would have to address that. And the applicants that I have seen to this point have considered the excavation and the resulting groundwater table after the excavation.

MEMBER RYAN: Just modeling, or with some measurements, or --

MR. OSWALD: I don't know the specifics of how they did all of the geotech work on that.

CHAIRMAN POWERS: I mean, say new things like how much does this thing weigh?

MEMBER RYAN: And I'm thinking ahead to things like, you know, the Tritium Task Force results and, you know, monitoring results in a place where you didn't expect them and flows that weren't exactly what you might have thought they were going to be and so forth. So, I guess there's work to do for the COL in that area.

MR. OSWALD: Yes. Can you put that down, the COL?

Okay. 2.4.1, hydrologic characteristics. Again, the applicant is required to describe the site-specific characteristics related to the hydrologic conditions.

2.4.2, floods.

CHAIRMAN POWERS: I think if we look at the guidance the staff gives in this area, that the applicant is required to characterize the hydrology of the site, and then he is required to consider alternatives. Do you give him any guidance on how to consider alternatives?

MR. OSWALD: We do not in the Certified Design.

CHAIRMAN POWERS: Please continue.

MR. OSWALD: We do not have in the Certified Design.

Floods, 2.4.2. Again, the applicant is required to investigate and describe the site-specific flood history, flood design features and the effects of local precipitation.

2.4.3, PMF, probable maximum flood of streams and rivers. Again, the applicant is required to determine the probable maximum flood from the streams and rivers and describe the effects of the flooding on that design for that site.

CHAIRMAN POWERS: And he takes into account the maximum 50-year flooding for this?

MR. OSWALD: I'll look. It's 50 or 100.

2.4.4, potential dam failures. The applicant is required to determine the potential for any upstream or downstream failures or any water control devices that may be upstream or downstream. Any natural water control devices or manmade devices we call out for the applicant to investigate.

All right. Next. 2.4 continues. 2.4.5, probable maximum surge and seiche flooding. The applicant is required to provide site-specific information on the probable maximum surge and seiche and the extent which safety-related structures will require protection. And again, they have to consider the wind effects on the surge and the seiche.

CHAIRMAN POWERS: Seiche is strictly a wind effect.

MR. OSWALD: No, it's not. It would be wind or seismic effects.

CHAIRMAN POWERS: It's a standing wave. A seiche is a standing wave.

MR. OSWALD: Yes, it would be the wind effects on the seiche.

CHAIRMAN POWERS: There's only been one in our nuclear power plants, so I guess we don't have to worry too much about them.

MR. OSWALD: Okay. 2.4.6, probable maximum tsunami flooding. Again, the applicant is required to provide the site-specific information on maximum flooding from a tsunami. Again determining --

CHAIRMAN POWERS: What do you require in your design basis for tsunami? I mean, what do you do with that?

MR. OSWALD: Well, we've looked at ground flooding -- really again, the maximum flood, we've got one foot below finish grade on flooding. And again, we've got our ground floor one foot above finish grade. So, you read that as the applicant would have to show that you've got the tsunami --

CHAIRMAN POWERS: Yes, but tsunami --

MR. OSWALD: -- one foot below the

finished grade elevation.

CHAIRMAN POWERS: But, I mean --

MR. OSWALD: Or protect for it.

CHAIRMAN POWERS: -- a tsunami is a probabilistic thing. So there must be some probability associated with that tsunami that exceeds your criterion.

MR. OSWALD: Right. And I don't know what that probabilistic requirement -- are you familiar, Ted, with the tsunami --

MR. MESSIER: I'm guessing that would be another PRA issue.

MEMBER SHACK: No, I mean, it's a design basis. Like your tornadoes is based on a probability of exceeding that kind of a wind speed. And you presumably would have sort of similar kind of criterion for the tsunami.

CHAIRMAN POWERS: Yes. And what I want to know is what the probability is.

MR. OSWALD: Right. Oh, the probability of --

MEMBER SHACK: Of exceeding your design basis tsunami.

MS. SLOAN: And again, I think that gets into COL space where it's beyond what we can speak for for design certification.

MR. OSWALD: We don't have that probability spelled out in the Certified Design. But they're required. We would point them to the NUREGs. And I do not know what that probabilistic number is.

MS. SLOAN: I think that's why it's a COL --

CHAIRMAN POWERS: Okay. So you would handle a tsunami just like it was flood?

MR. OSWALD: Right. Yes, from the structural perspective.

MEMBER STETKAR: I mean, theoretically also, to come back to the thing I'm accused of all of the time, is that theoretically the risk assessment should have a frequency for a range of tsunami impacts, if they've really done an assessment of the risk from external events, the same way as there would be a frequency, or people like to call it probability, for a range of different tornado loads. And since the risk assessment is part of the design certification package, that information should be in there, at least was assumed from that perspective.

MS. SLOAN: I think we're just going to

have to take a follow-up to get that information.

MR. OSWALD: Again, as was stated, we considered the maximum height, whatever that risk, whatever that frequency is, one foot below finish grade. If it's beyond that, if it's an exception, you're just going to have to describe how you're going to protect for it. Build a bern around, or whatever your options you want to select.

Ice effects, Section 2.4.7. The applicant is required to evaluate the site-specific ice effects, determine the forces on the structure and describe the protection required for the ice effects. Again, the COL applicant has to consider ice blockage and build up on any moving components such as fans, cooling fans.

2.4.8, cooling water canals and reservoirs. The applicant is required to provide the site-specific design basis for cooling water canals and reservoirs used for make up to the ultimate heat sink cooling water structures. Again, the U.S. EPR ultimate heat sink is provided by mechanical draft cooling towers in a safety-related, what we call a central service water structure. The make up intake structure is and the conduit is site-specific to the central service water building.

Section 2.4.9, channel diversions. The COL applicant is required to provide site-specific information on panels and -- in the event of diversion or rerouting of the source of the cooling water and that alternate water supplies are available for safety-related equipment.

Any questions on this slide?

CHAIRMAN POWERS: I see none.

MR. OSWALD: Okay. We'll move on. Hydrology continues.

CHAIRMAN POWERS: It just won't give up, huh?

MR. OSWALD: 2.4.10, flooding protection requirements. Again, the applicant is required to provide a description of all the static and dynamic effects of flood conditions and how the safety-related equipment is protected.

2.4.11, low water considerations. The applicant is required to identify any natural events that may reduce or limit cooling water supplies.

2.4.12, groundwater. The applicant is required to identify local and regional groundwater reservoirs, subsurface pathways, on-site groundwater usage, and any necessary monitoring measures and any effects on the structures.

2.4.13, pathways of liquid effluents in the ground and surface waters. Again, the applicant has describe the ability of the surface and groundwater to delay, disperse, dilute or concentrate radioactive effluent releases and the effects on future use of water resources around the site.

2.4.14, tech spec and emergency operation requirements. The applicant has to describe any emergency measures to implement flood protection and verify adequate water supply for shutdown.

MEMBER STETKAR: Todd, just remind me; I have to admit ignorance here, the U.S. EPWR design does have a separate ultimate heat sink cooling water basin, right? I think you mentioned --

MR. OSWALD: In the essential service water building, yes.

MEMBER STETKAR: in the essential service water area?

MR. OSWALD: Yes.

MEMBER STETKAR: So you don't rely on an open-loop system?

MR. OSWALD: That's correct.

MEMBER STETKAR: Yes, I keep picturing

the plant in France, which is an open-loop design.

MR. OSWALD: Open. Right. Right.

MEMBER STETKAR: But this is --

MR. OSWALD: Closed-loop. Again, the only external is the make up --

MEMBER STETKAR: It's just make -- yes, I mean, you need make up to it, but it --

MR. OSWALD: Right.

MEMBER STETKAR: Okay. Thanks.

MR. OSWALD: Yes.

MEMBER STETKAR: Thank you.

MR. OSWALD: Okay. Now the fun stuff. 2.5, geology, seismology and geotechnical engineering. In Section 2.5, the applicant has to investigate and characterize the site, describe the site and do a probabilistic seismic hazard assessment to determine the site-specific SSE. Again, the EPR FSAR considers a range of generic soil profiles and applies an appropriate Certified Design response spectra. We have three spectra; soft, medium and hard that would be associated with the right soil condition, the soil column.

And Section 2.5.1, the basic geologic and site information. The COL applicant has to define the regional and site geology.

Section 2.5.2, the vibratory ground motion. The applicant has to define the site-specific SSE motion from the probabilistic seismic hazard assessment and compare the site-specific SSE with the certified seismic design response spectra parameters in the EPR, in the FSAR. Again, our three different control motions with the associated soil profiles.

MEMBER SHACK: You have ten profile grouped into three. Now, is that really three profiles that you use?

MR. OSWALD: It's actually ten different soil columns. We have layered conditions and we have uniform half-space soil columns. So some of these are low-shear wave velocities or soft sites. Some of them are high-shear wave velocities or hard sites. So, we have our ten soil columns and then we put either a soft or a medium or a hard applied to the appropriate soil column. So there's really ten different ground motions, ten different seismic/soil conditions. Now, two of those overlap. You know, we'll put -- one of them has a hard and medium applied to it and one of them has a medium and a soft applied to it. It kind of falls in between. So we actually run a total of 12 different profiles.

MEMBER SHACK: Okay. So, I mean, you really do have 12 different --

MR. OSWALD: Yes, at this point right now that's what's in our Certified Design is our 12 profiles. We were trying to get a broad range of conditions to make sure that we try to envelope as much as we can.

CHAIRMAN POWERS: I guess I'm a little confused about this. If you ask me what is the acceptance spectrum for the EPR, why don't I just take the soft site spectrum?

MR. OSWALD: Well, what we've actually found was the medium spectrum ended up driving a little more, depending on the soil profile that you use. We had a hard profile and a medium profile that were really the predominant drivers in the --

CHAIRMAN POWERS: So why not pick one of those and then say that's what the EPR will do?

MR. OSWALD: We're working on that. As we have figured out what are the controlling motions, we recognize that we have --

CHAIRMAN POWERS: Has this design or components of this design ever been put on a shaking table?

MR. OSWALD: I cannot speak for what has

been done in the European design as far as the -- of course the structure obviously hasn't been placed on shake table, but at this point in the U.S. we have not procured any testing or components.

CHAIRMAN POWERS: Okay. It's a matter of fact.

MEMBER SHACK: Can I ask my PRA question just to get it --

CHAIRMAN POWERS: Yes.

MEMBER SHACK: Okay. I'll ask my PRA question now. And I don't expect an answer. I just haven't looked at the PRA.

Do you happen to know whether the risk assessment has quantified a frequency of seismic-induced core damage, or have they just simply done a seismic margins analysis?

MR. OSWALD: They've done a seismic margins analysis.

MEMBER SHACK: Okay. So we don't know what the seismic risk is?

MR. OSWALD: (Off microphone.)

MEMBER SHACK: Right. Okay. Thanks. That helps.

MR. OSWALD: Our Certified Design response spectra, the three, hard, medium and soft, all anchor to a .3g peak ground accelerations. Again, that's defined as the hypothetical free field outcrop motion at the basemat elevation for the nuclear island common basemat. This design has one large basemat for most everything, and then we have the diesel and the ultimate heat sinks off the common basemat.

CHAIRMAN POWERS: I guess I didn't realize that. The diesels are on separate basemats?

MR. OSWALD: Yes, the diesels are in separate buildings. Part of the separation criteria we'd use for extreme hazards. That's part of the design.

CHAIRMAN POWERS: And we find that that was the cause of difficulties at the Japan earthquake. They have two things that moved differently and the connections are the problem.

MR. OSWALD: Yes.

CHAIRMAN POWERS: Okay. Interesting.

MR. OSWALD: Okay. In 2.5.2.6 is where we describe the reconciliation process, how you take what's in the Certified Design response spectrum versus your site-specific ground motion, or SSE. And again, in 2.5.6, we recognize a site-specific soil structure interaction evaluation may be used to do that reconciliation. If it's not obvious that you have your soil column enveloped and your ground motion enveloped, the two together, then you do the site-specific SSI analysis, which is pretty much where we end up with most of the time.

Section 2.5.3, surface faulting. The applicant must investigate the region for surface faults. The U.S. EPR does not allow surface faults under safety-related structures.

CHAIRMAN POWERS: Let me ask a question. In principle I doubt that there's any place in the world that has not had a fault at one time or another, if I go back to the age of the universe or age of the planet. So surely, inactive faults underneath the structure are not proscribed, are they?

MR. OSWALD: Inactive faults are not proscribed.

CHAIRMAN POWERS: Surely, they must not be proscribed. Yes, of having an active fault. I mean --

MR. OSWALD: Oh, an -- I thought you said inactive. I was not -- okay.

CHAIRMAN POWERS: If I have an inactive fault in under my basemat, hadn't moved in the last billion years, then why do you care?

MR. OSWALD: I don't recall the --

MR. MUNSON: If I could maybe jump in. This is Cliff Munson. I'm the branch chief in the geosciences and geotechnical engineering.

We do look at surface faulting, but in a sense we're looking for rupture of a fault that could potentially happen underneath a nuclear structure. So it's not so much an inactive fault that's been dormant for several million years. We wouldn't consider that as capable and obviously the COL applicant would have to do investigations to make sure that it was not capable.

MR. OSWALD: That is the key word, capable faults.

MR. MUNSON: But what we're worried about is a fault that would potentially rupture underneath a nuclear structure.

MR. OSWALD: Okay. 2.5.4, stability of subsurface materials and foundations. The applicant is required to submit information about the properties and stabilities of soils that may affect the plant facilities under static and dynamic conditions including the certified design response spectra or the site SSE of the site-specific structures.

Section 2.5.5, stability of slopes. The applicant must evaluate all slopes, natural and manmade of the site-specific SSE. Again, no slope failures are considered in the Certified Design.

Are there any questions on 2.5?

(No audible response.)

MR. OSWALD: Okay. That concludes what AREVA has to present.

CHAIRMAN POWERS: In looking ahead, I happened to notice that in the next presentation we're going to talk about what, 13 SE open items? You have any comments about those?

MR. OSWALD: The open items, there's one on the bearing capacity, how we calculated the bearing capacity, the dynamic bearing capacity. The comment on that was we have a value currently in the FSAR of approximately 26 ksf. The initial FSAR submittal had about 34.5 ksf. Initially in our sliding and overturning evaluation, we took a toe pressure value from that evaluation to come up with our dynamic bearing capacity. That was the 34.5 ksf number. Now we have 26.1 ksf dynamic bearing capacity. And that's done in our SASSI analysis. Again, in our sliding and overturning evaluations we've taken the maximum value that we determine under the basemat in our SASSI analysis in the SASSI Code as we were doing the sliding and overturning evaluation. And the staff is looking for more information on that. We had only provided the value and didn't provide the full explanation.

The other open items are consistency between use of the words "site characteristics" and "site parameters." I think I actually messed that up in one of the slides here, I noticed this morning. Recognize that. We'll clean all of that up.

What are some of the other open items now? Some of them are -- they're mostly in your area.

MR. MESSIER: Mostly they're mine.

MR. OSWALD: Yes. So good.

MR. MESSIER: I'll just let you keep talking.

MR. OSWALD: No. No, no. I'm done with all I can say here.

MR. MESSIER: I'm sure the staff is going to present them. Quite a few of them are, you know, clarifications that have been requested that will be only too glad to provide.

CHAIRMAN POWERS: I was really looking for are there any that we're not going to resolved easily?

MR. MESSIER: I don't think so. No, none of that odor.

CHAIRMAN POWERS: Okay. That was the question I really had. But, we're on a pathway to get these -- that sooner or later all will get chaptered too with no open items.

MS. SLOAN: Hopefully sooner rather than later.

CHAIRMAN POWERS: You've stood up enough.

MS. SLOAN: Okay.

MR. OSWALD: Thank you, gentlemen for the staff.

CHAIRMAN POWERS: We're going to have to really put a string on you, Sandra. You're just too disruptive.

MS. SLOAN: Oh, there are plenty more chapters left.

CHAIRMAN POWERS: Oh, I'm sure.

MS. SLOAN: We'll have plenty of fun.

CHAIRMAN POWERS: When we get to Chapter 15, I'm sure that we will call out for pizza.

We're scheduled for a break.

PARTICIPANT: We are.

CHAIRMAN POWERS: Thank you. We will take that said break a bit early, but deserved nevertheless. And so we will resume at 20 of the hour.

(Whereupon, at 2:36 p.m. off the record until 2:40 p.m.)

CHAIRMAN POWERS: Let's come back to our discussions of site characteristics.

MS. TESFAYE: Thank you. Yes, this is the staff's portion of this afternoon's presentation. I'd like to go over the staff that will be dealing with the open items. Seshagiri Tammara is the one at the computer. He's sitting at the back in support. He doesn't have a presentation. Mr. Brad Harvey will be presenting 2.3, meteorology. Mr. Ken See will be presenting 2.4, hydrology engineering section. And Dr. Weijun Wang will be presenting 2.5, geology, seismology and geotechnical engineering.

Project manager support, myself and Jay Patel. Jay Patel unfortunately is not here to --

CHAIRMAN POWERS: He didn't come and visit with us, huh? Tell him that we missed him.

MS. TESFAYE: Okay. I'll do that.

So that's the staff that is responsible for Chapter 2.

Next slide is the --

CHAIRMAN POWERS: I may just comment that Mr. Harvey and Mr. Wang of course have been before this Committee several times with all the questions we asked before. I saw Brad roll his eyes. Mr. See, however, I think you're relatively new before us.

MR. SEE: This is my third appearance.

CHAIRMAN POWERS: Third appearance? Okay.

MEMBER SHACK: He only rolls his -- or lifts his eyebrows.

CHAIRMAN POWERS: He lifts his eyebrows.

Please continue.

MS. TESFAYE: Okay. One thing I'd like to say about this slide, you asked the question during the earlier presentation about the nature of the open items.

CHAIRMAN POWERS: Yes.

MS. TESFAYE: Here, in the projects and technical staff, we don't see a path forward in Phase 4. We will not allow anything to be just open. So usually the open items have some (off microphone.)

COURT REPORTER: Mr. Chair, could you remove that wrapper away from the mike?

CHAIRMAN POWERS: I can.

MS. TESFAYE: So that's the nature of these open items. Again, we have issue 45, request for additional information for this chapter. Thirteen of them are left open to be resolved in the fourth part of the application review.

Now the next couple of slides we've listed all the open items, but the ones that we're going to be discussing here this afternoon are the ones with red star in front of them. But after them are minor in nature and we'll now be discussing them. And again, I'm not going to go through this open item list. This is here just for completeness.

Slide 6, as you heard during our previous presentation, Section 2.1, geography and demography and Section 2.2, nearby industrial, transportation and military facilities. Here are our information items. And we don't have any specific presentation from the staff on those two sections.

But we are satisfied why is there an RAI from the original FSAR, but the applicant has included the correct COL information item in the FSAR.

With that, if you don't have any question for me, and I like to introduce Mr. Harvey to discuss meteorology, 2.3.

MR. HARVEY: Hello, my name is Brad Harvey. I'm a meteorologist for the Sizing and Accident Consequence Branch within the division of Site Environmental Reviews within the Office of New Reactors. I've been supporting the nuclear power industry for a little over 30 years in a meteorological role. I have a bachelor's from Rensselaer Polytechnic Institute in physics. I have a master's from the University of Michigan in atmospheric science. I've been with the NRC for a little over six years, during which time I've been involved as the primary meteorological reviewer for the first three Early Site Permits and I also provided a supporting role for the role of the Early Site Permit. I've been the leading meteorological reviewer for the three Design Certifications currently under review. I'm also reviewing several of the COLA applications that are before the ACRS, or will be shortly.

Before working with the NRC, I worked for Yankee Atomic Electric Company, an NRC licensee, for almost 20 years, and several consulting firms. And full disclosure, my last job before I joined the Agency was actually with AREVA. I was with AREVA for 15 months before I turned over to the dark side and started working for the regulator here.

CHAIRMAN POWERS: You left Sandra? Why? You're with the good guys now though. Oh, she looked at me.

MR. HARVEY: I'll be discussing SER Section 2.3 on meteorology.

Section 2.3, meteorology. Typically while site-specific information such as regional climatology, local meteorology, on-site meteorologic and measurements program, short-term atmospheric dispersion estimates for design basis accident releases and long term atmospheric dispersion estimates are routine releases, the EPR FSAR states that the COL applicant is to provide this information as part of the COL application. The staff finds this acceptable.

Meteorological site parameters. Tier 1, Table 5.0-1 and Tier 2, Table 2.0-1, of the EPR FSAR identify climatic and atmospheric dispersions site parameters. These site parameters are the postulated meteorological features assumed for the site which the applicant used to design its facility. The climatic site parameters were selected to ensure the facility is being designed such as potential threats from the physical characteristics of a potential site such as regional climatic extremes and severe weather will not pose an undue risk to the facility in accordance with GDC 2.

The accident atmospheric dispersion site parameters were selected to help demonstrate that the radiological consequences of design basis accidents, both off-site and in the control room, meet radiation dose criteria specified in 10 C.F.R. 5245 and GDC 19.

The routine release atmospheric dispersion site parameters were selected to help demonstrate that calculated off-site concentrations and dose consequences of routine airborne radioactive releases meet criteria specified in 10 C.F.R., Part 20 and Appendix I, 10 C.F.R., Part 50.

The COL applicant needs to demonstrate that his meteorological site characteristics fall within the EPR meteorological site parameters pursuant to 10 C.F.R. 52.79. Should the meteorological site characteristics not fall within the EPR meteorological site parameters, the COL applicant must provide supporting justification that the proposed facility is acceptable at the proposed site. The staff evaluated the EPR meteorological site parameters in accordance with the Standard Review Plan to ensure they are representative of a reasonable number of sides that may be considered within a COL application. Details regarding this evaluation will be presented during the next several slides.

Climatic site parameters. The EPR FSAR presents climatic site parameters related to winter precipitation for roof load design, maximum wind speed other than tornado, tornado, air temperature and the ultimate heat sink meteorological conditions, the winter precipitation site parameter values for roof load design. The applicant's winter precipitation site parameters are used to determine the winter precipitation live loads on the roof of seismic category 1 structures as discussed in FSAR Chapter 3.

The staff compared the applicant's winter precipitation site parameters barriers against snowfall data recorded at weather stations located throughout the contiguous United States and found that the applicant's site parameter values bounded most sites. The staff therefore concluded that there is reasonable assurance that the applicant's winter precipitation site parameter values can be expected to be representative of a reasonable number of potential COL sites. The staff finds this acceptable.

The maximum wind speed other than tornado site parameter values. The staff reviewed the applicant's maximum wind speed site parameter value by comparing it to wind loading design criteria presented in ASCE-705, which is the American Society of Civil Engineers' standard for minimum design loads for buildings and other structures.

The staff found that the EPR maximum wind speed site parameter value meets the ASCE-705 wind loading design criteria except for a small portion of the Coastal South and Southeast United States. Consequently, the staff included that the applicant's maximum wind speed site parameter value is representative of a reasonable number of sites that may be considered within a COL application.

The finds this acceptable.

CHAIRMAN POWERS: I'm struggling with -- suppose that you've gone in and found out only half the Continental United States had values within? That's okay?

MR. HARVEY: No.

CHAIRMAN POWERS: No?

MR. HARVEY: No, as a matter of fact, one of the open items regarding wet bulb temperature design basis, which is met by less than half of the sites in the United States. So we would ask that the applicant go back and reconsider beefing up the design using a higher design basis temperature or --

CHAIRMAN POWERS: Suppose it was 75 percent?

MR. HARVEY: The applicants have been telling us that their designs are able to be sited at between 70 and 80 percent of the sites throughout the United States. So, I would look for a number that at least met that --

CHAIRMAN POWERS: Oh, okay. So, you're looking for something more than 70 percent?

MR. HARVEY: Yes, generally that's correct.

CHAIRMAN POWERS: Just a question of

curiosity on my part.

MR. HARVEY: The tornado site parameter values. The staff reviewed the applicant's tornado site parameter values by comparing them to design basis tornado characteristics specified in Revision 1 to Reg Guide 1.76. The staff found that the tornado site parameter values chosen by the applicant are the same as tornado intensity Region 1 design basis tornado characteristics specified in Reg Guide 1.76 where Region 1 represents the central portion of the United States where the most severe tornadoes typically occur. The staff finds this acceptable.

There was a discussion earlier about the criteria for selection of these. It is basically a return period of ten to the minus seven per year is the frequency of tornado occurrence.

MEMBER STETKAR: It can't be a return period for the frequency of that intensity. It has to be something to do with also the probability that the tornado hits a certain target area. Because it can't be a ten to the minus seven return period.

MR. HARVEY: Target area is an area of 200-300 meters across.

MEMBER STETKAR: Two to three-hundred

square meters?

MR. HARVEY: I think if you look at the target as a linear. Because if the tornado is going this way, the path would be 200-300 meters across.

MEMBER STETKAR: Those frequencies are not supported by actual data. If you just look at tornado touchdown frequencies.

MR. HARVEY: Well again, most of the touchdowns are the lower strength tornadoes. The higher --

MEMBER STETKAR: Oh, that's absolutely true, but we're talking about touchdown frequencies.

MR. HARVEY: -- wind speeds that we're talking about. There is NUREG --

MEMBER STETKAR: I'm looking at that right now. I haven't read it yet. I'm looking at --

MR. HARVEY: Forty-four-sixty-one.

MEMBER STETKAR: -- actual tornado data that have been compiled to look at touchdown frequencies as a function of tornado intensity. And, you know, I'm not sure where in the United States you'd ever see a ten to the minus seven. Western North Central perhaps, but ten to the minus seven per year is just not supported in terms of a touchdown frequency. Now, an impact frequency, if the target is small enough, I could understand that. If it's a very, very small target. If you're looking at a point estimate target trying to hit.

MR. HARVEY: It's a little larger than a point estimate.

MEMBER STETKAR: But I haven't --

MR. HARVEY: Yes, the NUREG-4461 --

MEMBER STETKAR: I'm going to study that tonight. Thanks.

MR. HARVEY: Okay. The air temperature site parameter values. The applicant provided zero percent exceedance and one percent exceedance air temperature site parameter values for use in the design and sizing of plant cooling equipment. The zero percent exceedance values are stark high and low values, whereas the one percent exceedance values, assuming they are annual exceedance values, are values that are expected to be exceeded on average 88 hours per year since there are 8,760 hours in a typical year.

In reviewing the applicant's one percent exceedance air temperature site parameter values, the staff could not ascertain whether the one percent exceedance values were intended to represent annual or seasonal exceedances. In the SER, this is identified as open item 02.03.01-13.

The staff could not evaluate the reasonableness of the applicant's one percent exceedance air temperature site parameter values until the applicant indicates whether these site parameter values represent annual or seasonal exceedances.

The staff reviewed the applicant's zero percent exceedance air temperature site parameter values by comparing them against temperature data compiled by the American Society of Heating, Refrigeration and Air Conditions Engineers, or ASHRACE. There are over 600 weather stations scattered throughout the Continental United States. The staff found that except for the non-coincidence wet bulb site parameter value, the applicant's zero percentage exceedance air temperature site parameter value, found most of the weather stations listed in the ASHRACE database.

In response to a staff request for additional information, the applicant stated the non-coincident wet bulb site parameter is used solely as the design point in sizing the ultimate heat sink cooling towers and that the cooling tower design was validated using bounding time-dependent wet bulb temperature profiles from four COL application sites. Consequently, the staff has asked the applicant to consider deleting the non-coincident wet bulb as a site parameter because there is no benefit specifying a site parameter value that is known to be exceeded at a number of locations. In the SER, this is identified as open item 02.03.01-14.

The ultimate heat sink meteorological condition site parameter values. The EPR standard plant design includes four mechanical draft cooling towers which serve as the plant's ultimate heat sink. The applicant presented a 72-hour set of wet bulb and concurrent dry bulb temperature values as a site parameter. The applicant used these data as design values to evaluate the maximum evaporation and drift loss of water for the ultimate heat sink. It is not clear to the staff how a COL applicant can demonstrate that a 72-hour set of site-specific temperature values are bounded by the EPR's 72-hour set of site parameter values.

The applicant also presented another 24-hour set of wet bulb and concurrent dry bulb temperatures as a site parameter. The applicant can use these data as the design basis to evaluate minimum water cooling in the ultimate heat sink.

Again, it is not clear to the staff how a COL applicant can demonstrate that a 24-hour set of site-specific temperature values are bounded by the EPR 24-hour set of site parameter values. Consequently, the staff has asked the applicant to consider deleting these two tables as ultimate heat sink site parameter values and moving them into FSAR Chapter 9 to represent the ultimate heat sink design basis. The staff has also asked the applicant to consider adding a COL information item stating that the COL applicant should demonstrate that the ultimate heat sink cooling tower design is validated for their site using site-specific time-dependent temperature profiles. In the SER, this is also identified as part of open item 02.03.01-14.

Short-term dispersion site parameters for design basis accident releases. The exclusion area boundary, or EAB, and out of boundary at a low population zone, or LPZ, atmospheric dispersion, or chi over Q site parameters, are used in FSAR Tier 2, Chapter 15 to help demonstrate that the off-site radiological consequences of accidents meets specified radiation dose guidelines as specified at

10 C.F.R. 52.47.

The staff reviewed the applicant's EAB and LPZ chi of Q site parameter values by comparing them to the corresponding site characteristic values identified in the Clinton, Grand Gulf, North Anna and Vogtle Early Site Permits. The staff found that the applicant's EAB and LPZ chi of Q site parameter values bound the corresponding site characteristics for the four ESP sites. Consequently, the staff finds that the applicant's EAB and LPZ chi over Q site parameter values should bound a reasonable number of sites that may be considered within a COL application. The staff finds this acceptable.

CHAIRMAN POWERS: So you looked at North Anna, Clinton and Grand Gulf?

MR. HARVEY: And Vogtle.

CHAIRMAN POWERS: And Vogtle?

MR. HARVEY: Yes.

CHAIRMAN POWERS: So kind of a square in the middle of the country here. We've run into problems with chi over Q values for some other sites. Why didn't you look at those?

MR. HARVEY: Primarily I looked at these four, because these four were fully vetted in chi over Q values --

CHAIRMAN POWERS: That's true.

MR. HARVEY: -- by the staff.

CHAIRMAN POWERS: Yes. I mean, they had the imprimatur of a lot of people looking at them.

MR. HARVEY: And the other ones are still under review.

CHAIRMAN POWERS: Yes. Yes, that's true. And there's fair range there.

MR. HARVEY: Control room chi over Q site parameters are used in FSAR Tier 2, Chapter 15 to help demonstrate that the radiological doses of design basis accidents in the control room meet radiation dose guidelines specified in GDC 19. The staff identified two open items in the SER when it reviewed the applicant's control room chi over Q site parameters.

First, the applicant should clarify the source receptor plant configuration information required by COL applicants to model control room air intake chi over Q values. In the SER, this is identified as open item 02.03.04-7.

Second, the applicant should provide the source receptor plant configuration information required by COL applicants to model control room unfiltered and leakage chi over Q values. In the

SER, this is identified as open item 02.03.04-8.

CHAIRMAN POWERS: When I asked the applicant about did you ever put a model of this in a wind tunnel or anything, they indicated they had not. And so it's unclear to me, how do you model chi over Q for a plant?

MR. HARVEY: For the control room chi of Q?

CHAIRMAN POWERS: Yes, for the control room.

MR. HARVEY: That is using the ARCON96 model.

CHAIRMAN POWERS: Oh, okay.

MR. HARVEY: Which is under the guidance of Reg Guide 1.94.

CHAIRMAN POWERS: So you guys just believe?

MR. HARVEY: Well, that was developed 15 years ago by PNNL, Van Ramsdell, as was previously mentioned. Based on empirical data that existed at the time of dispersion results in the wake of nearby receptors and building wakes.

CHAIRMAN POWERS: -- of that empirical data had anything that looked like this plant?

MR. HARVEY: I think it probably

represented several different plant designs, existing plants at the time.

CHAIRMAN POWERS: It did. I mean, we know where. I mean, he says where we got his data.

MR. HARVEY: I'm sorry?

CHAIRMAN POWERS: He says where he got his data.

MR. HARVEY: Okay.

CHAIRMAN POWERS: Didn't look like Sandra's plant. I mean, she's got weird things sticking off of -- I'm picking on you, Sandra, if that's okay. I know you'll get even, right? So you just believe, right?

MR. HARVEY: Yes, because, you know, it was a result of a number of different configurations. I mean, I'm not sure that any one given plant is that different in terms of having continued building, reactor building, turbine building, so forth and so on.

CHAIRMAN POWERS: Okay.

MR. HARVEY: The staff cannot evaluate the reasonableness of the applicant's controlling chi over Q site parameter values until the applicant provides source receptor plant configuration information so that the staff can perform its own independent atmospheric dispersion modeling.

Once the applicant provides this information, the staff intends to generate a set of EPR-specific controlling chi over Q values using hourly meteorological data from the four approved Early Site Permit sites to see if the EPR controlling chi over Q site parameter values bound a reasonable number of sites that may be considered within a COL application. This is a staff confirmatory action.

Long-term dispersion site parameters for routine releases. The EPR FSAR utilizes routine release or annual average atmospheric dispersion chi over Q and deposition, or D/Q factors in FSAR Tier 2, Chapter 11 to calculate off-site concentrations and dose consequences from normal operations to demonstrate compliance of the off-site radionuclide concentration criteria in 10 C.F.R., Part 20 and the dose criteria in Appendix I to 10 C.F.R., Part 50.

The staff identified two open items in the FSAR when it reviewed the applicant's routine release chi over Q and D/Q values.

First, the routine release chi over Q value, but not the routine release D/Q value is identified as a site parameter. The staff has asked the applicant to also list the routine release D/Q value as a site parameter, because the routine release D/Q value is used in FSAR Tier 2, Chapter 11 to calculate doses to the maximally-exposed individual. In the SER, this is identified as open item 02.03.01-6.

And secondly, the applicant should clarify the release plant information required by COL applicants to model site-specific routine release chi over Q and D/Q values. In the SER, this is identified as open item 02.03.05-7.

The staff reviewed the applicant's routine release chi over Q and D/Q values by comparing them to the corresponding site characteristic values identified in the Clinton, Grand Gulf, North Anna and Vogtle Early Site Permits. The staff found that the applicant's routine release chi over Q and D/Q values bound the corresponding site characteristics for the four ESP sites. Consequently, the staff finds that the applicant's routine release chi over Q and D/Q values should bound a reasonable number of sites that may be considered within a COL application. The staff finds this acceptable.

Meteorological COL information items.

The EPR FSAR contains several meteorological-related COL information items which can be summarized as follows:

The COL applicant is to provide information on climatic and atmospheric dispersion site characteristics, and, if a COL applicant identified site-specific meteorological values outside the range of the EPR site parameter values, then the COL applicant will demonstrate the acceptability of the design giving the site-specific values and the appropriate sections of the COL application. The staff finds the scope of the applicant's COL information items to be appropriate.

In conclusion, pending resolution of the meteorological-related open items, the staff hopes to be able to eventually conclude that: 1) the applicant has identified an appropriate list of site parameters; and 2) the values assigned to each of the site parameters are expected to be representative of a reasonable number of sites that may be considered for a COL application.

Are there any questions?

CHAIRMAN POWERS: Any questions on this subject?

MEMBER STETKAR: No.

CHAIRMAN POWERS: I think when we get to the control room, we're going to go through that a little more carefully just as a point, because I need to understand better how you calculate one of these things, just to say head's up, because we will probably discuss that a little more carefully in connection with that. I don't think we'd make any progress discussing it here in connection with the site characteristics. Okay? Let's move on.

MS. TESFAYE: Okay. Thank you, Brad.

Our next presenter is Ken See and he'll present Section 2.4, hydrologic engineering.

Ken?

MR. SEE: Thank you. My name is Ken See. I'm a hydrologist in the Division of Site and Environmental Reviews, Hydrologic Engineering Branch and I'm going to discuss briefly Section 2.4, hydrologic engineering.

You've seen these sections before presented by AREVA, and I'm not going to go into each one of them in detail like they did. Needless to say that the COL applicant will have to provide information covering each one of these sections in their application.

CHAIRMAN POWERS: Well, I guess, I mean,

one of the things that we discussed in the hydrologic modeling of the site is you got to model the site now to put this plant, which weighs a lot, on it. The hydrologic model all changes.

MR. SEE: Yes.

CHAIRMAN POWERS: And do they provide in their application sufficient information in order for the COL applicant to in fact calculate how a hydrologic model on the site should be changed?

MR. SEE: Most COL applicants will have their now specific design, you know, for parking lots, impervious surfaces, things of this nature. There are drainage systems for extreme storm events. It's laid out in detail in their COL applications. And we haven't had any issues, interface issues between the DCD and the COL applicant. They're using pretty much standard plant layouts with some minor variations that are taken into consideration during the COL stage.

CHAIRMAN POWERS: But the COL applicant is responsible for -- well, I'm just asking; do they provide enough information to him, I mean, presumably you'll ask. I bet after he's bought something he probably has a little clout to get information.

MR. SEE: Yes. The answer is yes.

CHAIRMAN POWERS: Okay. See, I'm so easy to place.

MR. SEE: Unlike the meteorology sections, we only have three parameters to deal with.

CHAIRMAN POWERS: Does that reflect that you're more sophisticated or less sophisticated than the meteorologists?

MR. SEE: We're just better. Better. Just kidding.

The first two, they're variable weather level, which is roughly a meter and they're flood level, which is a foot below grade. Those values identified in other applications, like AP1000 or ESBWR, they are very close to the values that were presented in the Utility Requirements Document and evaluated in NUREG-1242. So we believe those values are reasonable.

Earlier there was some discussion about how are we going to ensure that they meet these requirements, and our branch is looking at the possibility of getting the COL applicants to commit in their safety analysis reporting commitment to monitor their data if we believe there's, you know, a probability of them exceeding these values. So, as part of any NEI 08, they're doing monitoring anyway for radioactive. So we're not talking about a large (off microphone). So we are thinking about these issues.

The maximum rainfall rate they're using here comes straight out of the hydrometeorological reports 51 and 52, so we have no issues with that.

CHAIRMAN POWERS: So you're really happy?

MR. SEE: Yes, we have no items. You know, they've done their job.

CHAIRMAN POWERS: You are good, aren't you?

MR. SEE: We had a few clarifying questions, but they're all resolved. Yes.

Any other questions?

(No audible response.)

CHAIRMAN POWERS: Let's charge ahead.

MS. TESFAYE: Thank you, Ken.

Next presenter is Dr. Wang. He'll be doing 2.5, geology, seismology and geotechnical engineering.

Dr. Wang, please?

DR. WANG: Good afternoon. My name is

Weijun Wang. I'm a geotechnical engineer at the NRC. I get some talking about myself.

I'm going to present the summary of staff review on the U.S. EPR, Section 2.5. There are five subsections in Section 2.5 and AREVA already present all the requirement for the COL applicant. So I won't repeat that.

The Section 2.5 is related to geology, seismology and geotechnical engineering. Before I go on for the presentation, I would like to point out there is a mis-concept about the Section 2.5, because some people the geology, seismology, the so forth, as all site-specific. So therefore, it's nothing in here in the standard design. The alternate is not the case. Because for any reactor, you have to build on a site and put that structure on some type of foundation and support by some material. In structure analysis you have to assume some soil profile there. You have to consider all the loading come from static load or the dead load, dynamic load and the seismic load. So because that, the designer has to assume some site parameters here.

And also the focus on two aspect for these sections. One is we review the assumed site parameters to see those parameters are reasonable and to see those site parameters consider that most potential U.S. site for new reactors. The other aspect is we look that to see the all the requirements for the COL applicant are following the guideline of our regulatory.

So, based on that, we found out that the standard design for the U.S. EPR establish the subsurface acceptance criteria and the site parameters for a site. For example, it provides the site parameter for minimum bearing capacity, the minimum shear wave velocity, subsurface uniformity and the maximum settlement amount other site parameters.

We still have one open item which is and AREVA already point out, because the Mr. Chairman asked a question what's the open item, which is regarding the dynamic bearing capacity. The FSAR of the U.S. EPR provided the values for dynamic bearing capacity, but it did not provide the details how this value was determined. And the staff think that's important because the dynamic bearing capacity is affect by many factors, if not the structure itself. It's affected by the soil profile used in the analysis and affected by all the loading conditions and the combinations. So therefore, we need to get the detail, the information about the analysis the applicant performed and they model they use, and how they got those value.

Another point I would like to present is something unique for this U.S. EPR design, which is this design provided three, not single one, is three certified seismic design response spectra. So because of that, we issue RAIs regarding this feature. And we are clear. I believe it's clear to us that all three the CSDRS are standard design, which were based on the curve generated in soil profile in the design structural analysis. And then they divided the other ten soil profiles into three groups, namely soft, medium and hard site. And all the three response spectrum are anchored on .3 g peak ground acceleration. Next slide it will show the figure of that three seismic designs response spectra.

So, if you look at this slide, there are three curves that represent the response spectra for the soft, medium and the hard site. And this then design and also the response to our staff RAI made it clear for any site you have to perform your site-specific site response spectra. And then you need computer. You have the force, the site-specific force with those other design response spectrum. And as I consider U.S. site-specific soil profile with other ten generic soil profile used in the design and then to see if the site-specific, the force is enveloped by one of the three, the standard design response spectrum. So if for any reason, for example, your soil profile, your site-specific soil profile is outside of the group or your site-specific not enveloped by one of the standard design, you have to perform a site-specific SSI analysis. So this is a very unique feature here. So that's why I would like to present here.

MEMBER SHACK: But do they actually end up covering then a wider range of conditions, or have the other people been more conservative in choosing the profiles?

DR. WANG: Well, to answer your question, first of all, the people can't design anything. They can assume that any the seismic input for their design. But the point here is, those assume, right? It's not something real for one particular site. But those assumed response spectra have to cover most of the potential site in the U.S.

And another point here, if you assume a very wide or broad the site-specific response spectrum as your input, that will require you to design a structure that can withstand less kind of the seismic input. That will make the structure design more difficult.

On the other hand, if you use a very the low seismic response spectra as your input, you certainly then will be much easier, but you will have hard time to find a site that fit your design. So it's hard to say which design is more conservative and which one is less conservative.

MR. MUNSON: But I think it's fair to say; this is Cliff Munson, that the EPR design is looking to be able to be sited at a number of sites. This is the reason why they use the three different spectra. And we're hearing that perhaps there's going to be a fourth to cover even more of the harder rock sites in the future. So that's --

MEMBER SHACK: Their intent certainly is to cover a very broad range of sites.

MR. MUNSON: Right. So that just means they have to do more homework in showing that their structures and components can withstand this ground motion.

MEMBER SHACK: And there's going to be a lot of analysis here.

MR. MUNSON: Right.

DR. WANG: Now, I come down to the conclusion. Except for the open items and first we feel the postulated parameters, the site parameters used as a design basis reasonable and I already gave some examples there. And all the site parameters are list in the Tier 1, the table 5.1-1 and also in Tier 2, table 2.1-1. I will not list any of those.

And also, we feel the requirement for the COL applicant to establish a site-specific characteristics in determining whether they meet the standard design parameters followed the NRC regulatory guidelines. That's the end of my presentation.

CHAIRMAN POWERS: You're happy.

DR. WANG: Yes, I will say because base on our review we looked at the site parameters. Like I mention it before, the seismic certified the seismic design response spectra. The other site parameters such as the like the bearing capacity, like the settlement requirement and the minimum shear wave velocity requirement, and also other parameters such as like the soil yield weight and like internal fraction angles. Those parameters are really in both that we see in the range of the engineering practice. Like I gave you example, if I see like a site parameter saying the soil yield weight like 80 pound per cubic feet, I will say no, it's not a reasonable design because in engineering practice you will probably -- as very few places will find a soil yield weight like 80 pound per the cubic feet. The problem is just the math, you know? Like a mistake in math, something like that.

So, as long as I see all the parameters within the normal range of engineering practice, yes, I'm happy with that.

CHAIRMAN POWERS: One of the questions that comes up is, we have recently had in Japan a very significant earthquake and both of the plants affected by that earthquake did fine by and large, but by and large means a lot of things. The question comes up, how do we know that the set of parameters we use to characterize a seismic event are indeed adequate? Because things happened at that plant.

DR. WANG: Well, to answer your question, yes, in Japan they experienced a much higher seismic event than the original designs. All

I can tell to you now is that issue NRC is in consideration. But for this particular design, it's one because in the U.S. and we have not had that magnitude of the earthquake for any the either existing nuclear power plant site or any potential site. As the standards design I would say that like for the all the seismic response spectrum anchor, a .3 g max peak ground motion of the region is reasonable assumption here. And also because our regulatory guide requires at least .1 g peak ground motion of the region. So based on that, at least for their standard design it meet our regulatory guidance. And I think my branch chief Cliff may want to add something regarding the seismic.

MR. MUNSON: If you'll recall Dana, we have our performance-based approach now for seismic for establishing the site-specific GMRS. And that's set at ten to the minus five for the onset of inelastic deformation, which is well short of seismic core damage, or the kind of frequencies you'd expect for core damage. So, I think the requirements we have in terms of what we require the siting the COL applicants and the ESP applicants to use to determine their ground motion in conjunction with what Weijun was talking about in terms of the certified design. And then the requirements for them, if they exceed the Certified Design to do site-specific SSI to show. I think those requirements would ensure that -- you know, we never know that there's -- you know, there could be a fault, you know, that we don't know about, but you'd think that there would be seismicity and some sort of, you know, the geologic characteristics and evidence that we look at to determine the seismic characterization. I think we're pretty demanding in terms of that criteria.

CHAIRMAN POWERS: Yes, I agree with everything you've said and this really isn't an issue for the COL applicant or the staff, either one. It's a question more of your research program, whether we have an adequate characterization of seismic events or not. So maybe I'm just thinking aloud here.

Okay.

MEMBER SHACK: I do have a question, though. You know, we always base this on this onset of inelastic deformation, which is fine for structures. But it's never clear to me that that's the right criterion that we're making sure that all our components meet. And, you know, we've changed the seismic hazard and I'm sure the building will still be standing --

CHAIRMAN POWERS: And everything works inside.

MEMBER SHACK: You know, I'm not quite as confident that everything will be working.

MR. MUNSON: Yes, this kind of gets into our engineering Chapter 3 kind of --

MEMBER SHACK: Right. It's a different topic.

MR. MUNSON: It's a different topic, so I'm probably not the best person to discuss this. But I do know that they have specific shake table requirements for electrical components and, you know, mechanical components also.

MEMBER SHACK: Yes, but when you've done that and you've changed the seismic hazard, you know, we always sort of base this on the probability that we've seen in seismic PRAs up to now, and you kind of then went back and based those as though the structural thing was the limit. And it's not clear to me that that's always been the case.

MR. MUNSON: Yes, and I know we look at much more than just structures in --

MEMBER SHACK: Okay. It's a topic for a

different discussion.

CHAIRMAN POWERS: We got to keep track of all this.

Okay. Any other questions?

You're done, right?

MS. TESFAYE: Pretty much. I forgot to mention that we had the list of acronyms at the back.

CHAIRMAN POWERS: We probably couldn't have survived with out them, right? Now I know what EAB means, yes.

MS. TESFAYE: I'll make sure to mention this --

CHAIRMAN POWERS: I don't think you need to. I think you've done --

MS. TESFAYE: That concludes our presentation of Chapter 2.

CHAIRMAN POWERS: Any other questions to present?

(No audible response.)

CHAIRMAN POWERS: Okay. Then, Mr. Stetkar, you owe me something. Mr. Ryan, I'd appreciate something from you, sir.

MEMBER RYAN: Thank you, sir.

CHAIRMAN POWERS: And as I outlined at

the beginning of this meeting, we are not going to bring this topic up at this coming ACRS meeting, that we will wait until some time after our meeting on the 19th. I assume you'll all be there. And we will collect those things together and then we'll make a decision on what to take to the full Committee. So, I will probably inform the full Committee that we've had this meeting. I will probably not say anything beyond though what the topics were.

So with that, unless there are any other comments from the members --

PARTICIPANT: Move to adjourn.

CHAIRMAN POWERS: -- then I will adjourn us.

(Whereupon, the meeting was adjourned at 3:36 p.m.)

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Presentation to the ACRS Subcommittee

AREVA EPR Design Certification Application Overview

Getachew Tesfaye
Project Manager

November 3, 2009

Major Milestones Chronology

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

12/02/2004	Pre-application activities began
12/11/2007	Design Certification Application submitted
02/25/2008	Application accepted for review (docketed)
03/26/2008	Review scheduled published
01/29/2009	Phase 1 review completed
03/19/2009	Revised schedule published
05/29/2009	U.S. EPR FSAR, Revision 1 submitted
06/25/2009	Revised schedule published
Aug-Oct,09	Phase 2 review completed for Chapters 2,8,10, and 12.
11/03/2009	ACRS begins Phase 3 review

Review Schedule

Task	Target Date
Phase 1 - Preliminary Safety Evaluation Report (SER) and Request for Additional Information (RAI)	Completed
Phase 2 - SER with Open Items	June 30, 2010
Phase 3 – Advisory Committee on Reactor Safeguards (ACRS) Review of SER with Open Items	September 28, 2010
Phase 4 - Advanced SER with No Open Items	April 2011
Phase 5 - ACRS Review of Advanced SER with No Open Items	July 2011
Phase 6 – Final SER with No Open Items	September 2011
Rulemaking	February 2012

ACRS Phase 3 Review Plan

FSAR Chapters Grouped by Phase 2 Completion Date							
Group	Chapters	Chapter Issuance	ACRS Meeting	Group	Chapters	Chapter Issuance	ACRS Meeting
1A	2	08/31/2009	**11/03/2009**	**3**	3	04/02/2010	**May 2010 (2 days TBD)**
	8	08/20/2009			7	04/02/2010	
1B	10	10/19/2009	**11/19/2009**		9	04/07/2010	
	12	10/07/2009			18	03/30/2010	
2A	4	11/17/2009	**02/02/2009 & 02/03/2009**	**4**	1	05/28/2010	**July 2010 (3 days TBD)**
	5	12/22/2009			6	05/11/2010	
	16	12/30/2009			13	04/08/2010	
	17	12/03/2009			14	05/28/2010	
2B	11	01/25/2009	**03/03/2009**		15	05/11/2010	
	19	12/22/2009					
Closing: ▪General Plant Description (final) and summation of open items ▪Cross-cutting issues and re-visit earlier chapters as needed							**Sept 2010 (1 day TBD)**

AREVA NP Inc.

Presentation to ACRS

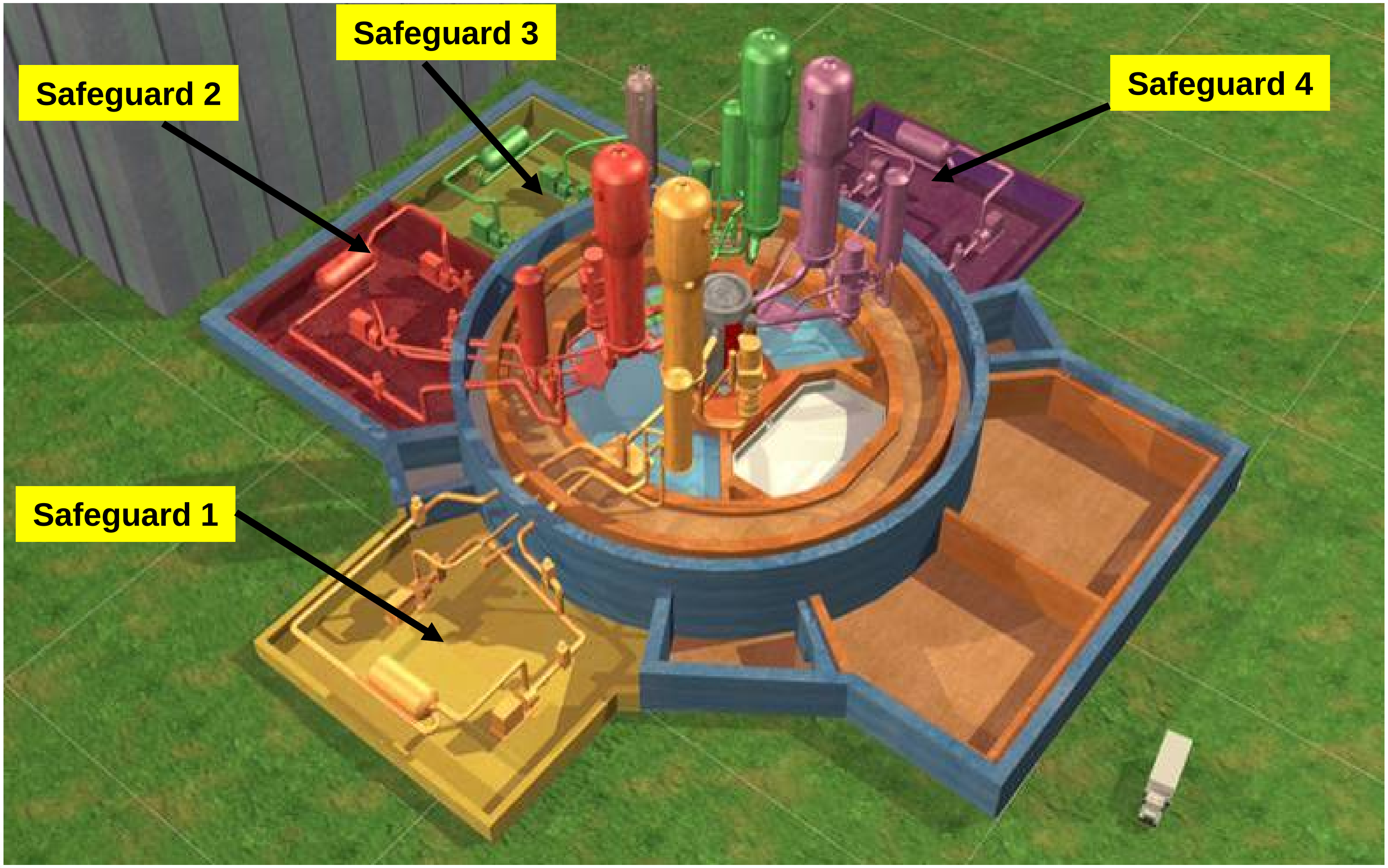
U.S. EPR Subcommittee

Design Certification Application
FSAR Tier 2 Chapter 8

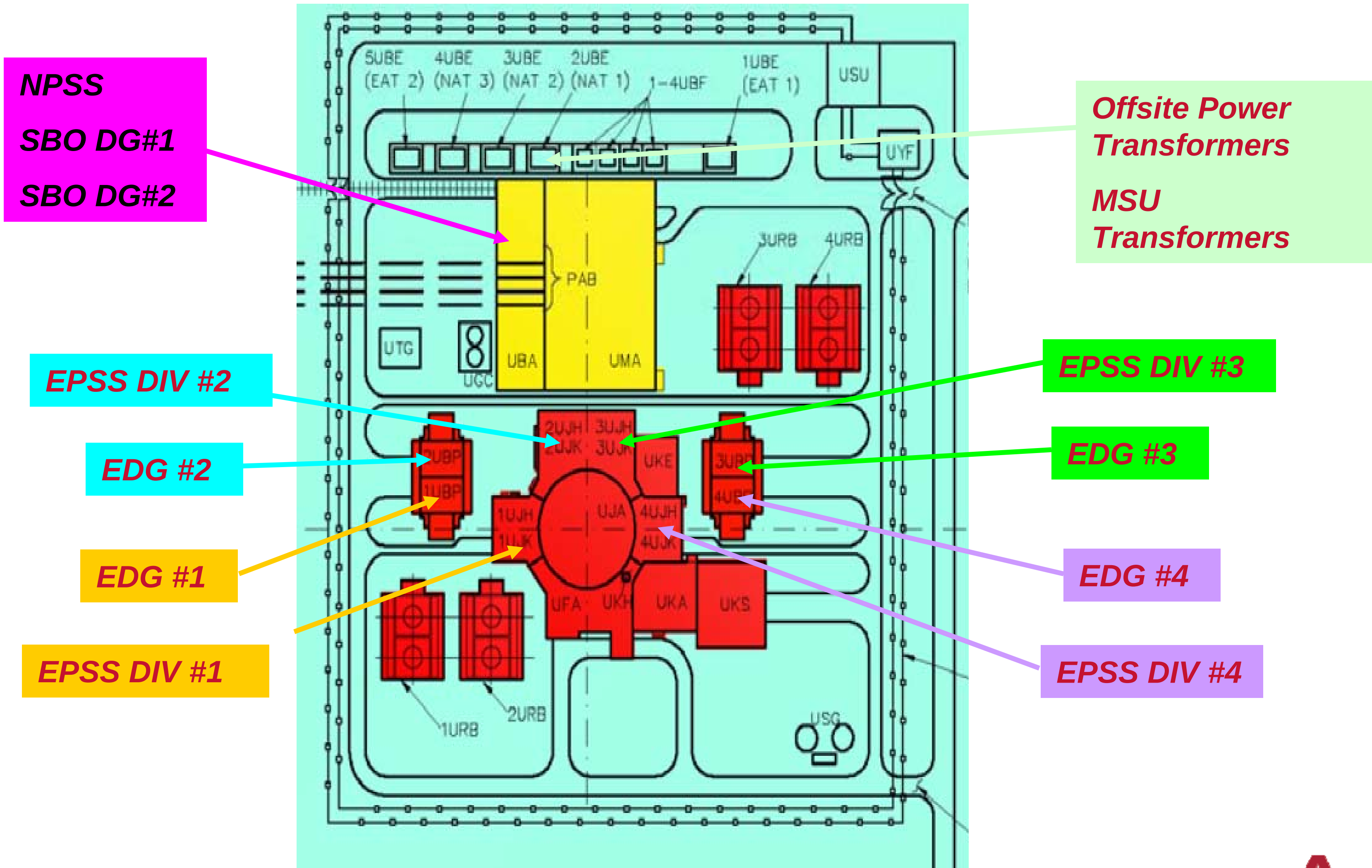
Chapter 8, Electric Power: Chapter Topics

- 8.1 Introduction
- 8.2 Offsite power system
- 8.3 Onsite power system
- 8.4 Station blackout
- Summary

Chapter 8, Electric Power
8.1 Introduction
U.S. EPR Safeguards Divisions



Arrangement of Electrical Systems



Chapter 8, Electric Power
8.1 Introduction
U.S. EPR Electrical Systems

- **Switchyard – COLA Specific**
- **Offsite Power**
  - **3 Normal Auxiliary Transformers (NATs) – offsite power to non-Class 1E buses**
  - **2 Emergency Auxiliary Transformers (EATs) – offsite power to Class 1E buses**
- **Onsite Power AC**
  - **Normal Power Supply System (NPSS) – non-Class 1E buses (6 trains)**
  - **Emergency Power Supply System (EPSS) – Class 1E buses (4 divisions)**
  - **Emergency Diesel Generators (EDGs) – 4 EDGs**
  - **Station Blackout Diesel Generators (SBODGs) – 2 SBODGs**
- **Onsite Power DC**
  - **Non-Class 1E Uninterruptible Power Supply (NUPS) – non-Class 1E (2 trains)**
  - **Class 1E Uninterruptible Power Supply (EUPS) – Class 1E (4 divisions)**
  - **12 Hour Uninterruptible Power Supply (12UPS) – non-Class 1E (2 trains)**

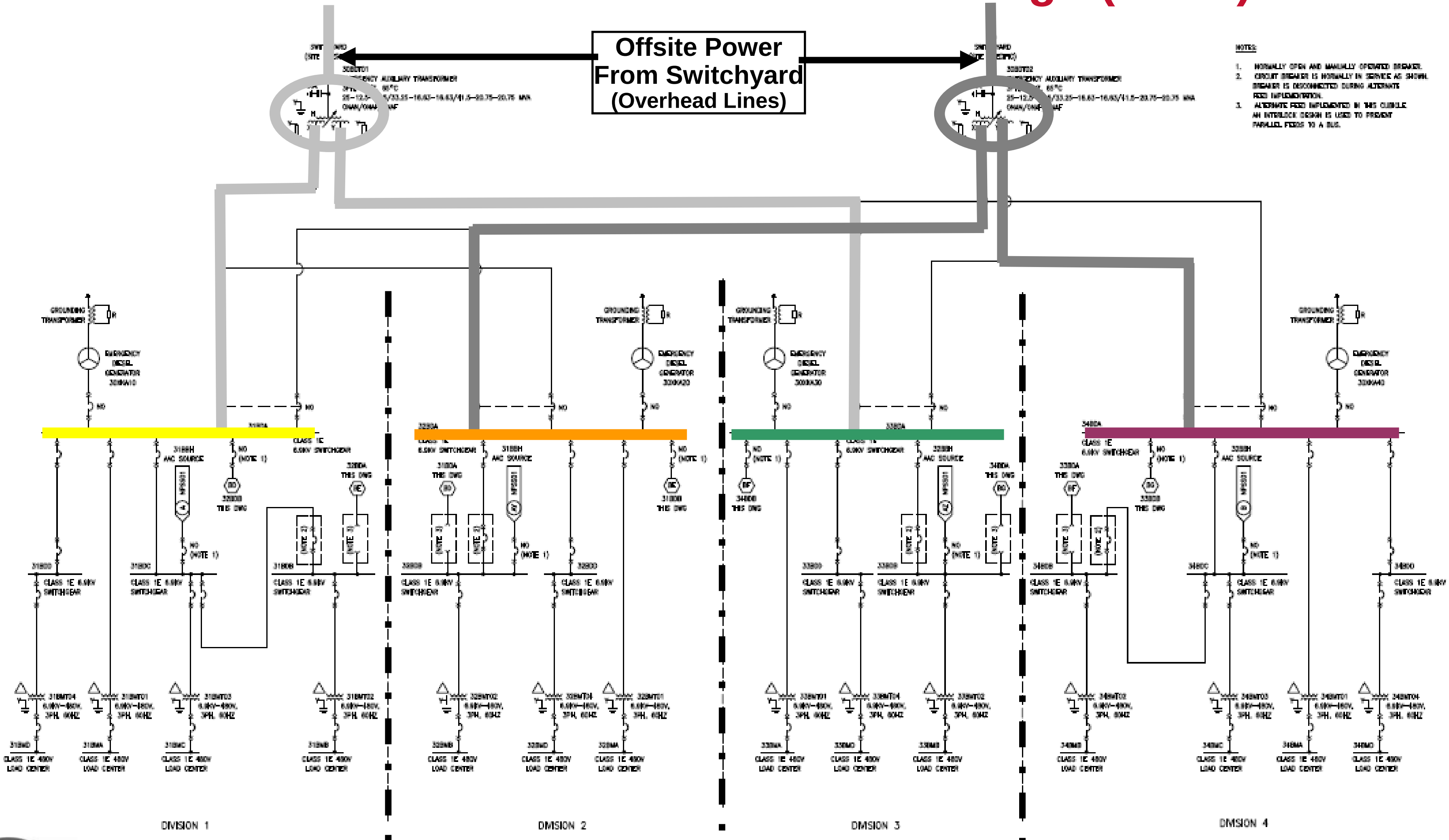
Chapter 8, Electric Power
8.1 Introduction
U.S. EPR Design Overview

- **U.S. EPR™ Design features that are fundamentally the same as previous designs**
  - Two Independent Offsite Feeds
  - Degraded Voltage System for Emergency Buses
  - Emergency Diesel Generator Load Sequencing
  - Containment Electrical Penetration Protection
  - 2 Hr Emergency Battery Capacity (X4)
  - Station Blackout Diesel Generator added or Coping Capability Verified

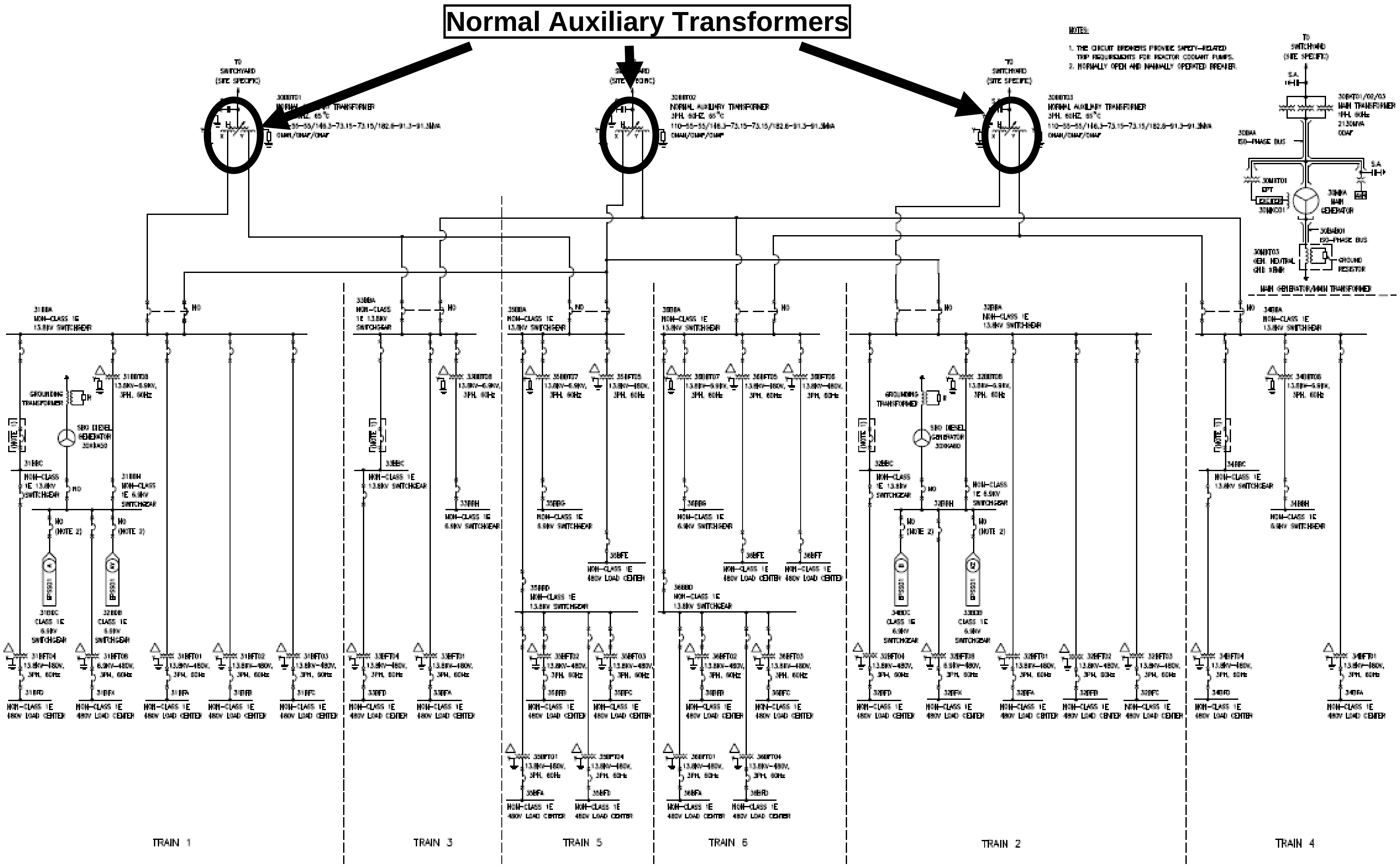
Chapter 8, Electric Power
8.1 Introduction
U.S. EPR Design Overview

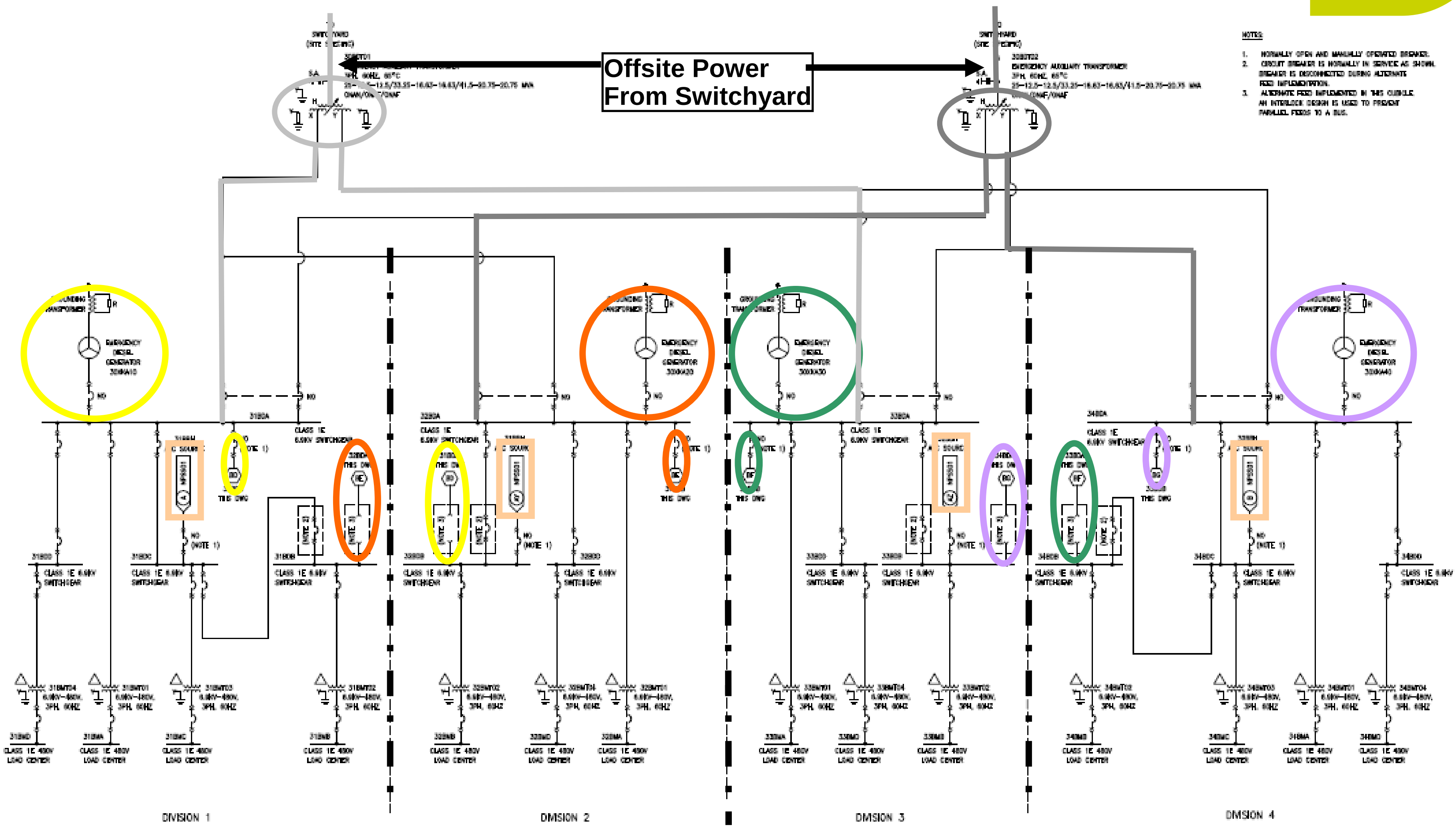
- **What is Different?**
  - Four Emergency Diesel Generators (EDGs) Per Unit
  - Alternate Electrical Feed Configuration
  - Diesel Load Sequencer is part of the I&C Protection System
  - Two Station Blackout Diesel Generators
  - No Fast Transfer of Plant Loads During Startup, Shutdown, or Plant Trip
  - Separate Offsite Feeds (from SWYD) to Safety and Non-Safety Buses
  - Island Mode
  - 12 Hr Uninterruptible Power Supply (12UPS) System

Chapter 8, Electric Power
8.2 Offsite Power System
U.S. EPR Design (EATs)

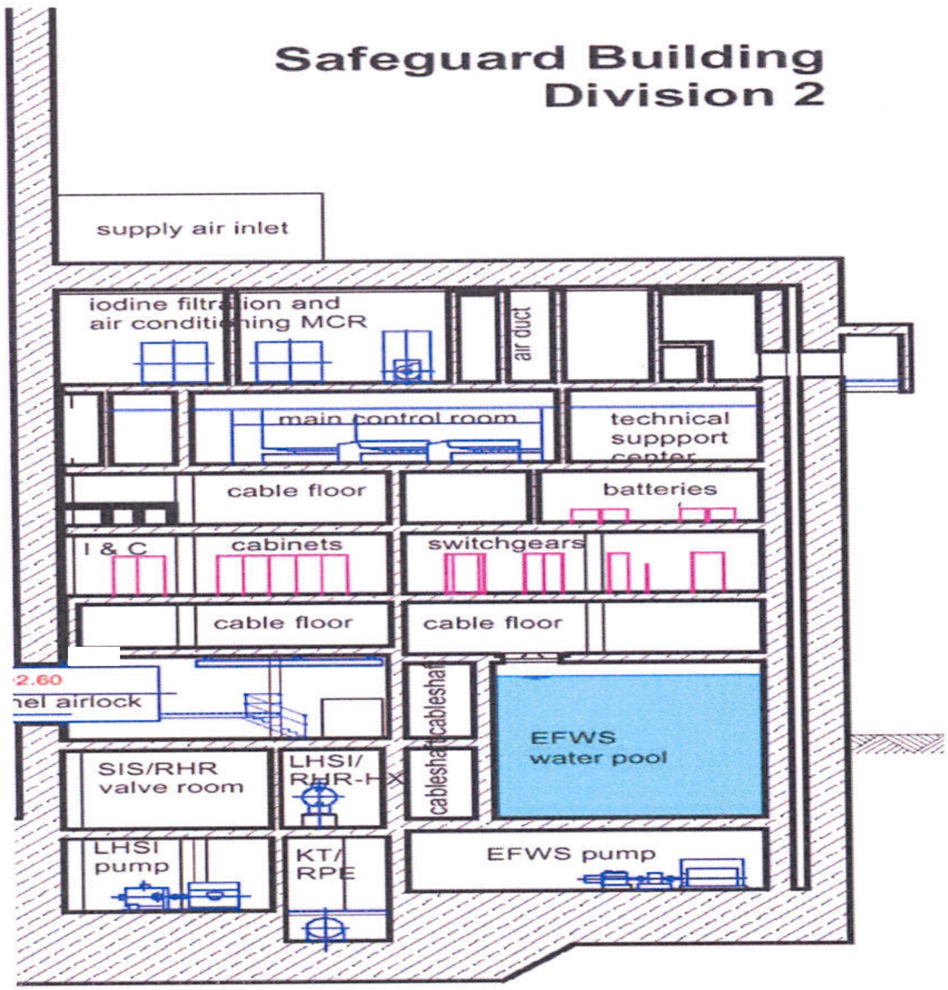


Chapter 8, Electric Power
8.2 Offsite Power System
U.S. EPR Design (NATs)




Offsite Power From Switchyard
NOTES:
1. NORMALLY OPEN AND MANUALLY OPERATED BREAKER.
2. CIRCUIT BREAKER IS NORMALLY IN SERVICE AS SHOWN. BREAKER IS DISCONNECTED DURING ALTERNATE FEED IMPLEMENTATION.
3. ALTERNATE FEED IMPLEMENTED IN THIS CUBICLE. AN INTERLOCK DESIGN IS USED TO PREVENT PARALLEL FEEDS TO A BUS.
EMERGENCY AUXILIARY TRANSFORMER
GROUNDING TRANSFORMER
EMERGENCY DIESEL GENERATOR
CLASS 1E 6.9KV SWITCHGEAR
CLASS 1E 480V LOAD CENTER
DIVISION 1
DIVISION 2
DIVISION 3
DIVISION 4

Equipment Location



Chapter 8, Electric Power
8.3 Onsite Power System
Emergency Diesel Generators

- Emergency Onsite Power Sources – Four emergency diesel generators (EDGs)
- Minimum EDG output - 9500 kW
- EDG load sequencing performed by the I&C protection system vice a dedicated load sequencer
- Physical separation
  - Electrical separation within Safeguards Buildings
  - Two EDG Buildings located on opposite sides of Reactor Building
  - Each diesel generator is separated within EDG building

Chapter 8, Electric Power
8.3 Onsite Power System
Alternate Feed, Maintenance Flexibility

- **Alternate feeds are designed to enhance operational capability and flexibility**
- **Alternate feeds can only be established between Division 1 and 2 (one divisional pair) or Division 3 and 4 (another divisional pair)**
- **Two train components completing redundant safety functions are aligned to different divisional pairs.**

8.3 Onsite Power System
Alternate Feed Divisional Loads

Alternate Fed Loads	DIV 1	DIV 2	DIV 3	DIV 4
EFW Valves	X	X	X	X
MSIV's / MSRT's	X	X	X	X
MFW Isolation Valves	X	X	X	X
S/G Isolation Valves	X	X	X	X
PCIV's	X	X	X	X
Anti Dilution Valves	X			X
Extra Boration System	X			X
Fuel Pool Cooling System	X			X
Annulus Ventilation	X			X
KLC System	X			X
CR Iodine Filtration	X			X
2hr Battery Chargers	X	X	X	X
HVAC Support / Emergency lighting	X	X	X	X

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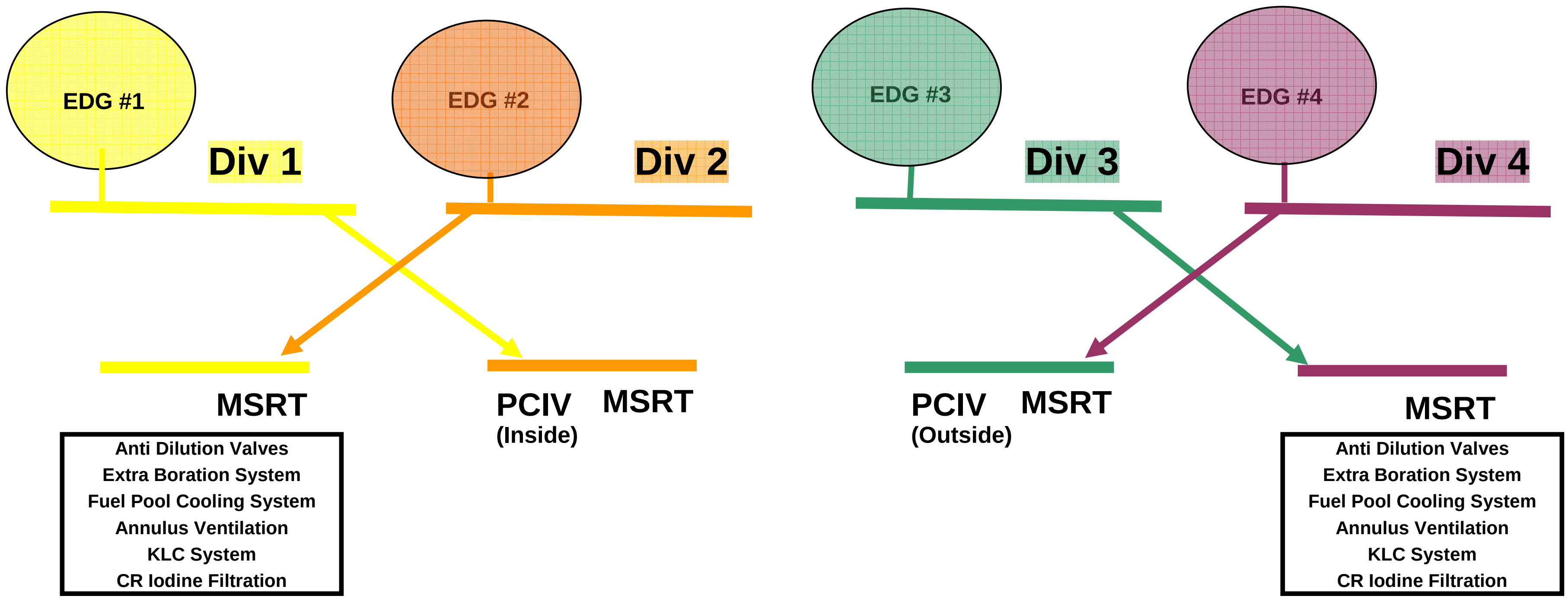
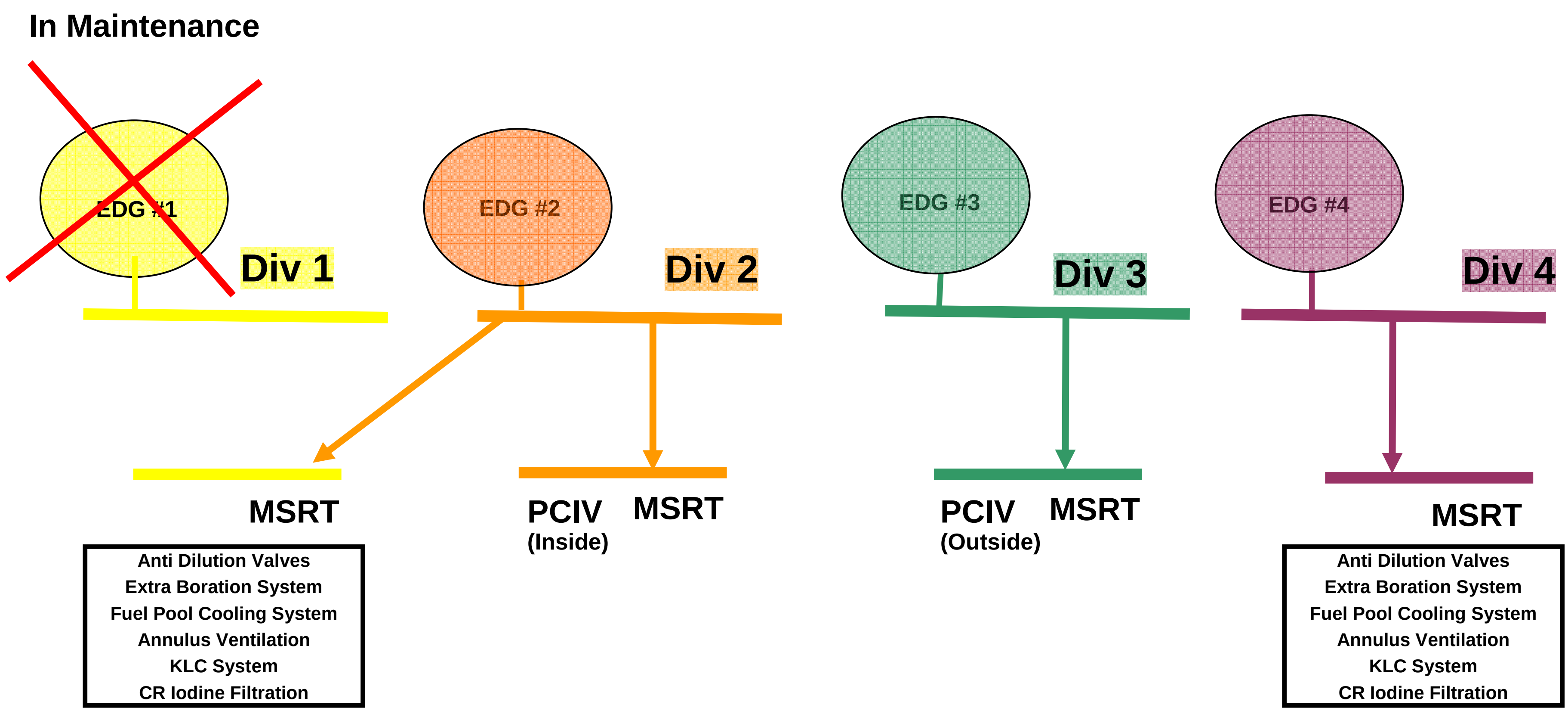
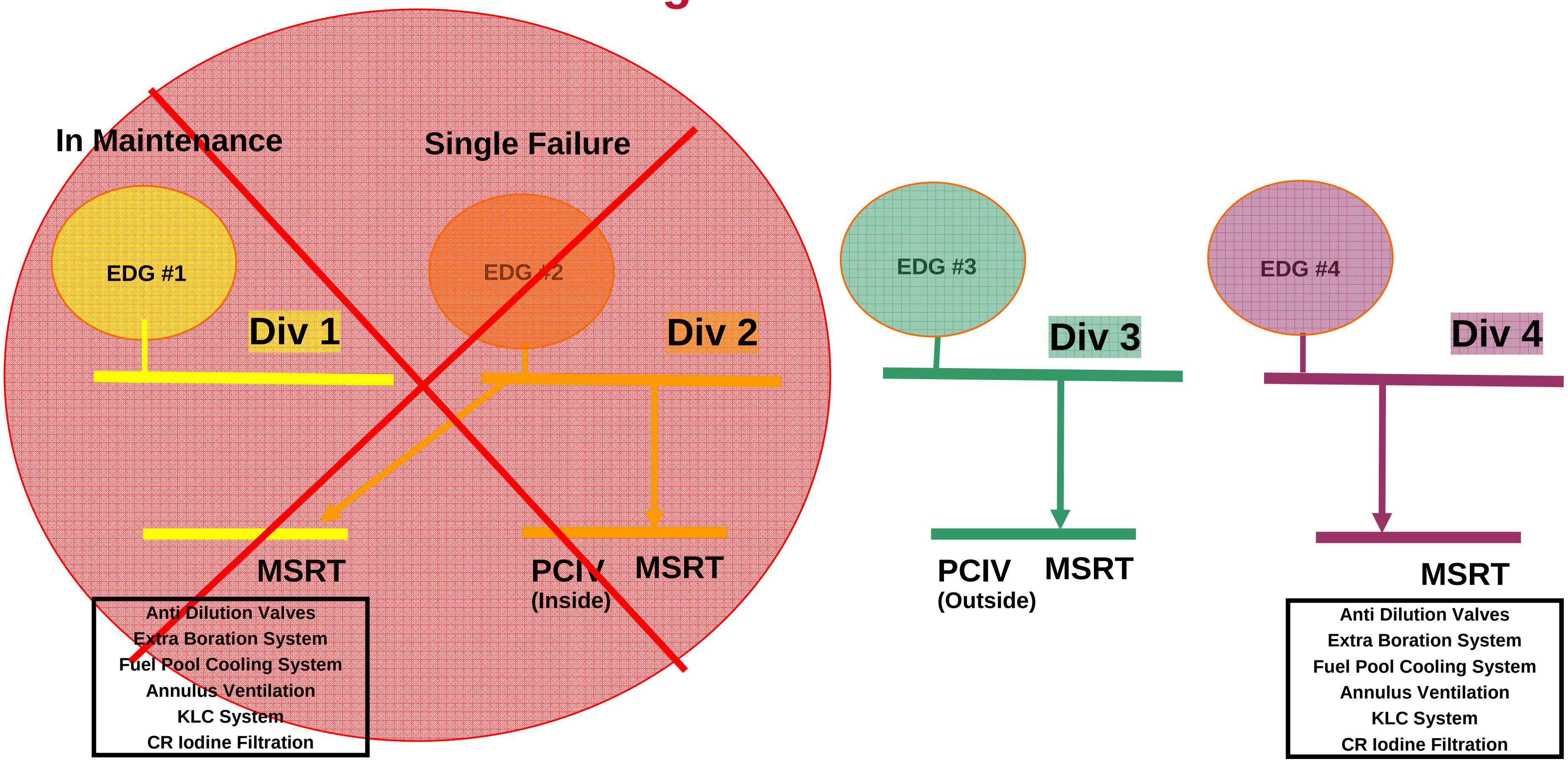
Chapter 8, Electric Power
8.3 Onsite Power System
Divisional Pairs



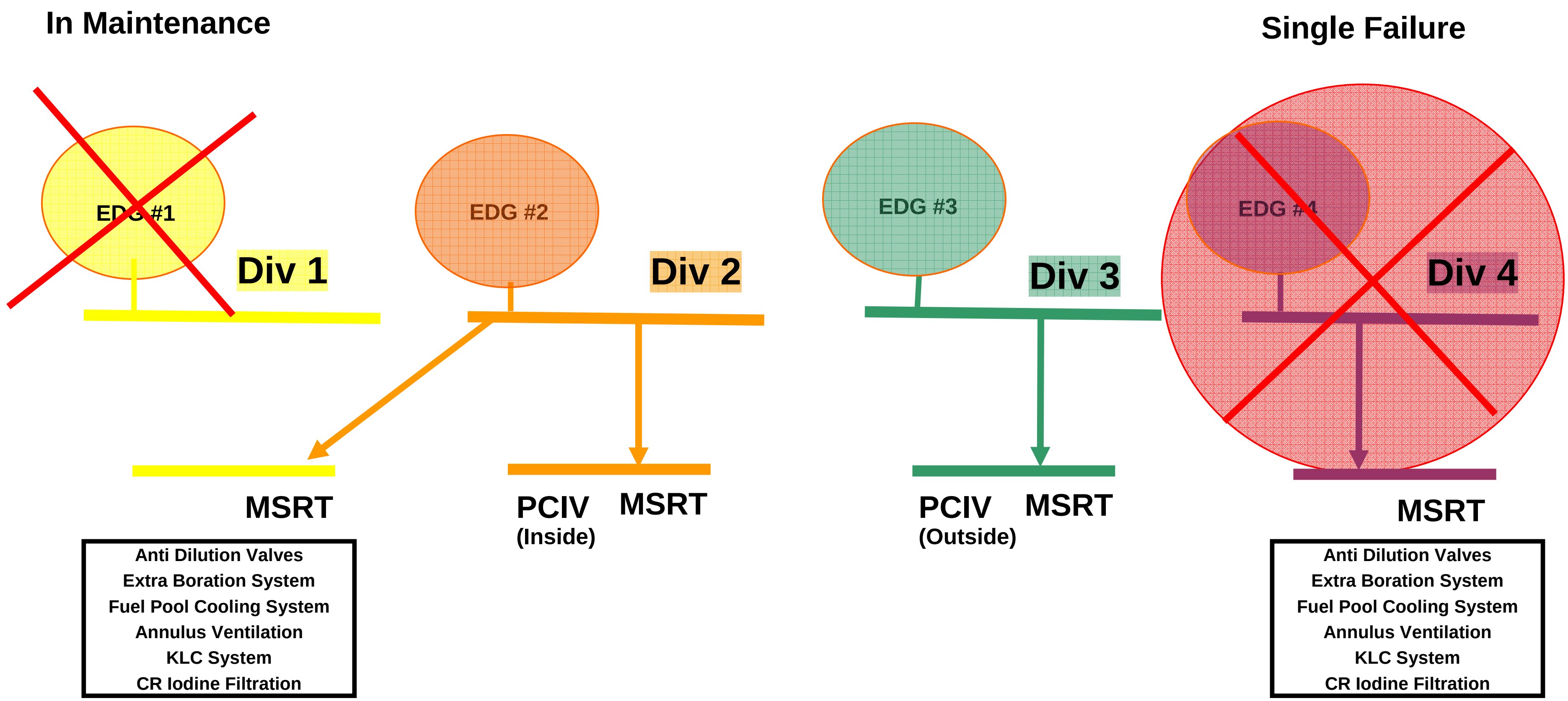
Chapter 8, Electric Power
8.3 Onsite Power System Divisional Pairs Alignment for EDG No.1 in Maintenance



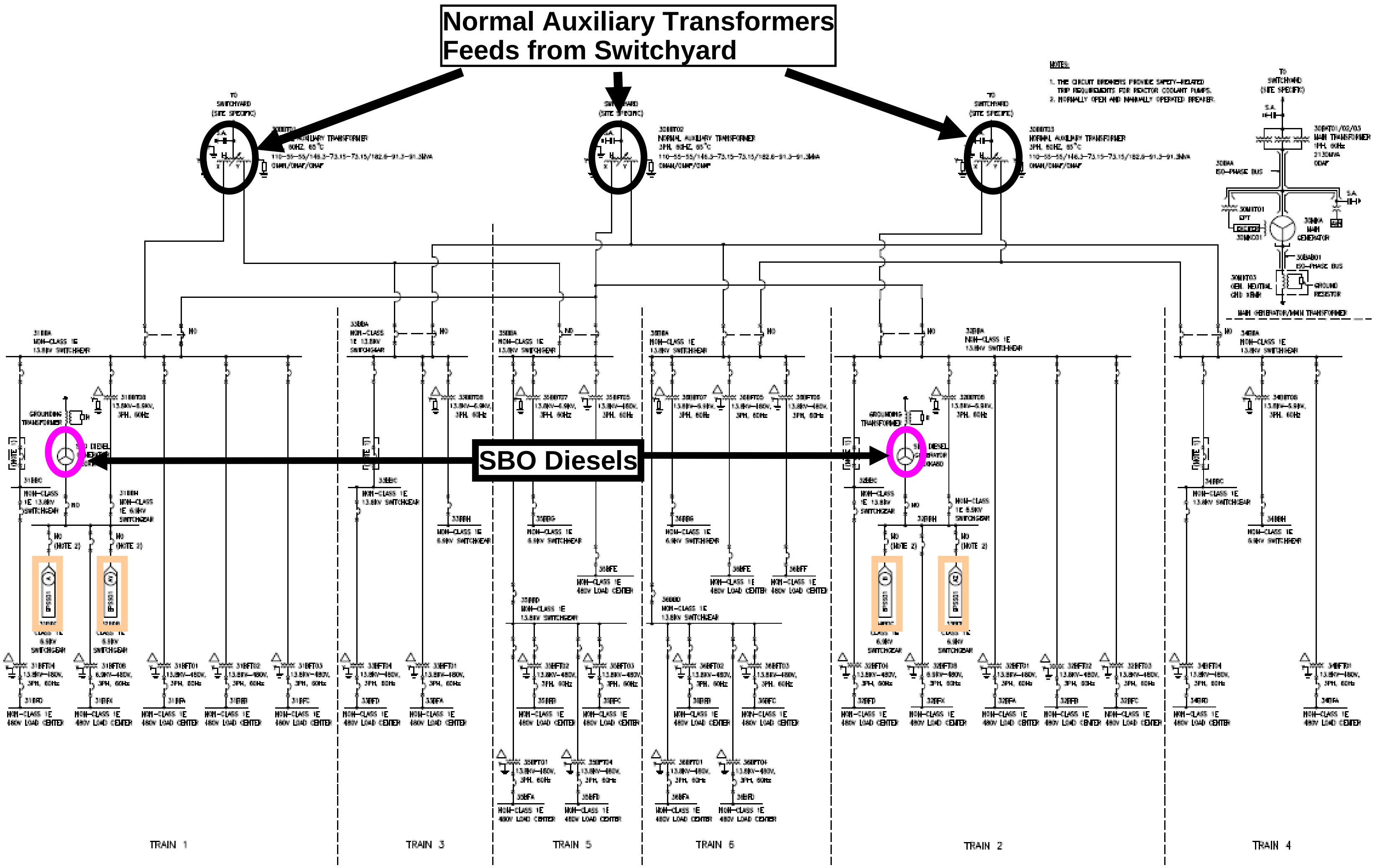
Chapter 8, Electric Power
8.3 Onsite Power System Divisional Pairs
Event - EDG No.1 in Maintenance
Single Failure of Division 2 EDG



Chapter 8, Electric Power
8.3 Onsite Power System Divisional Pairs Event - EDG No.1 in Maintenance Single Failure of Division 4 EDG



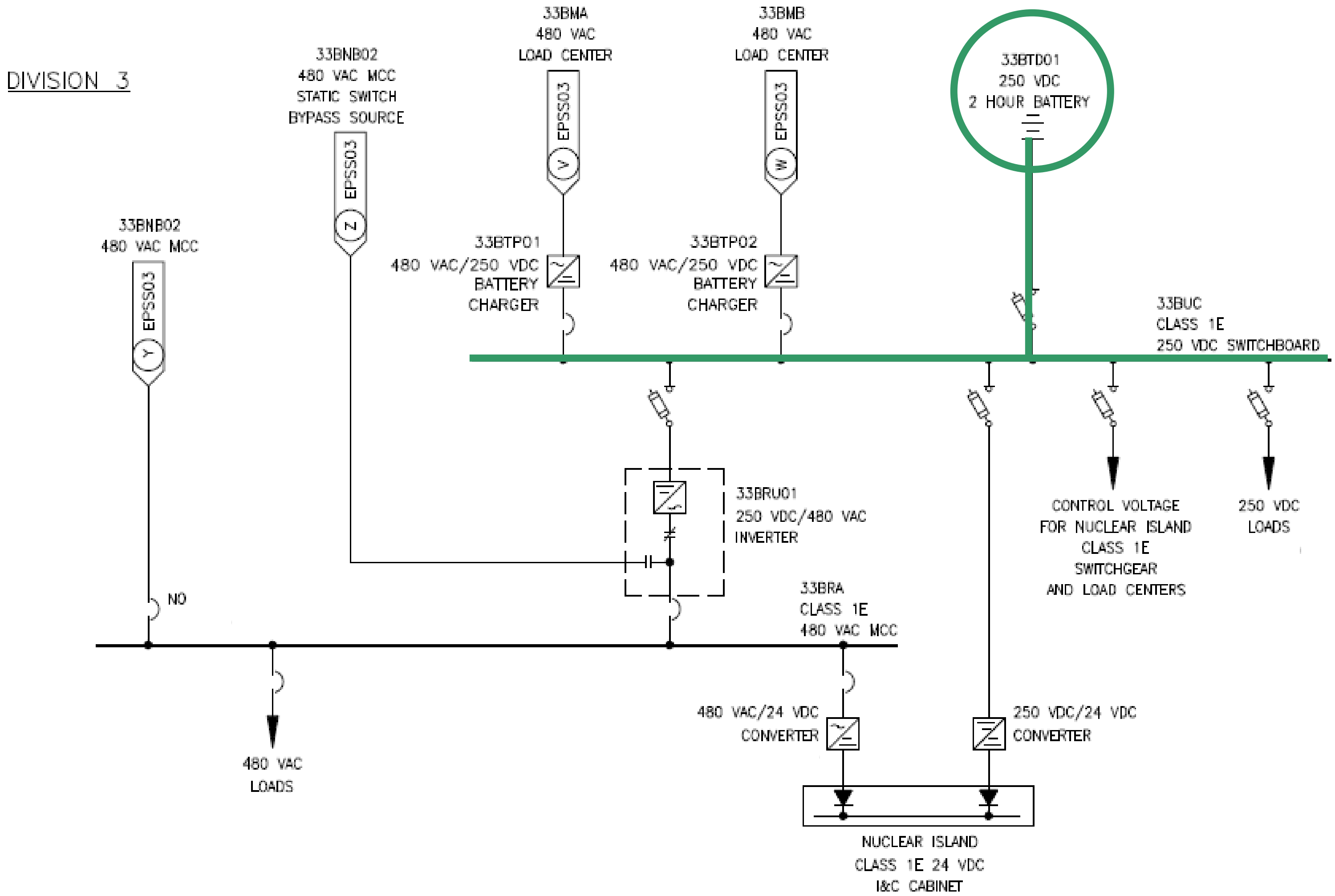
Chapter 8, Electric Power
8.3 Onsite Power System
Non-safety power



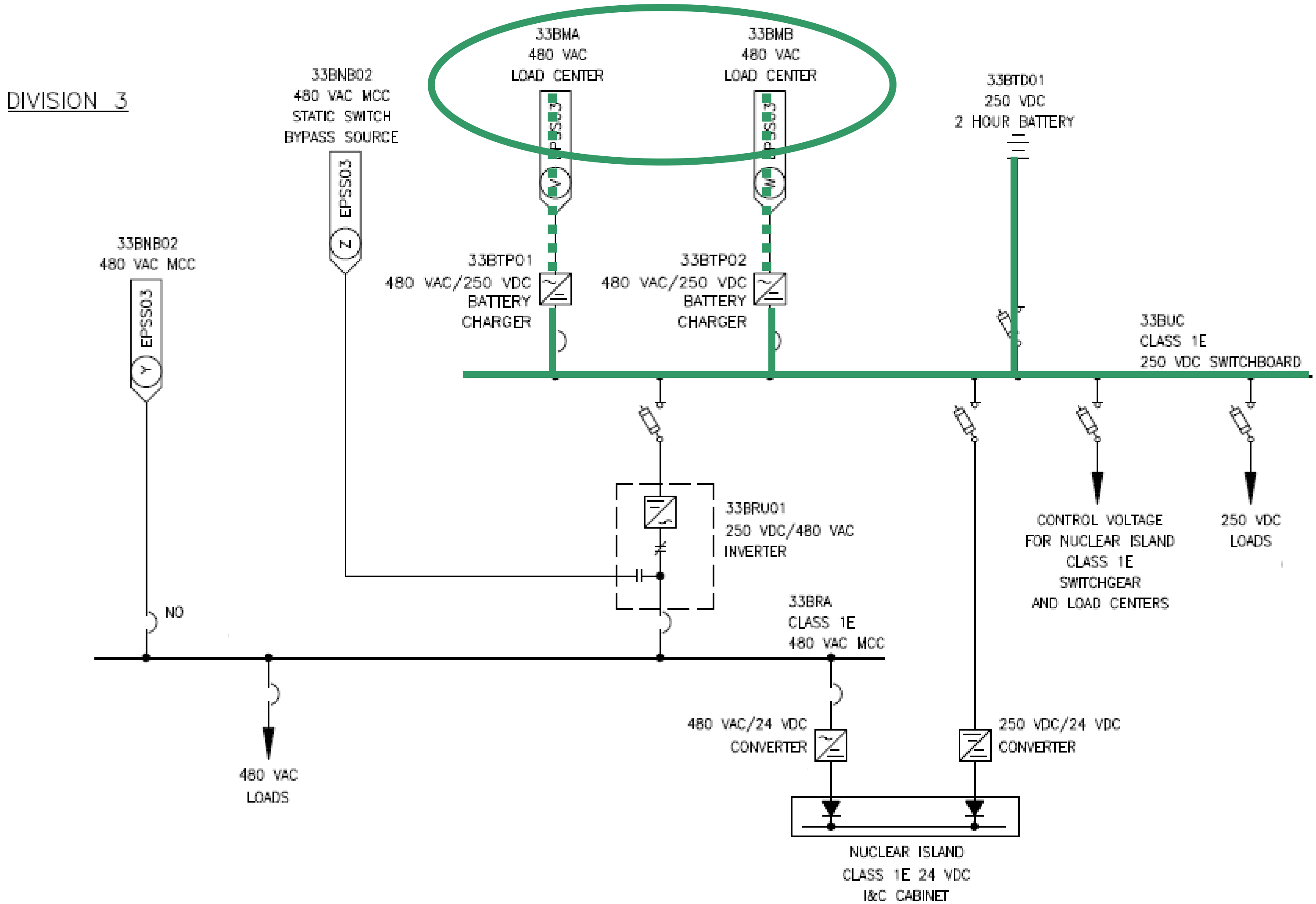
Class 1E Uninterruptible Power Supply

- **EUPS System**
  - 4 Divisions of Class 1E batteries and chargers
  - Two battery chargers per division
  - Battery chargers are capable of being fed from the SBODG
  - Redundant feeds to I&C cabinets
- **Lessons Learned from Forsmark**
  - Ensure selectivity between battery charger and inverter protection and coordination settings
  - A power feed from the Class 1E 250 VDC bus through a 250 VDC/24 VDC converter to the I&C cabinets

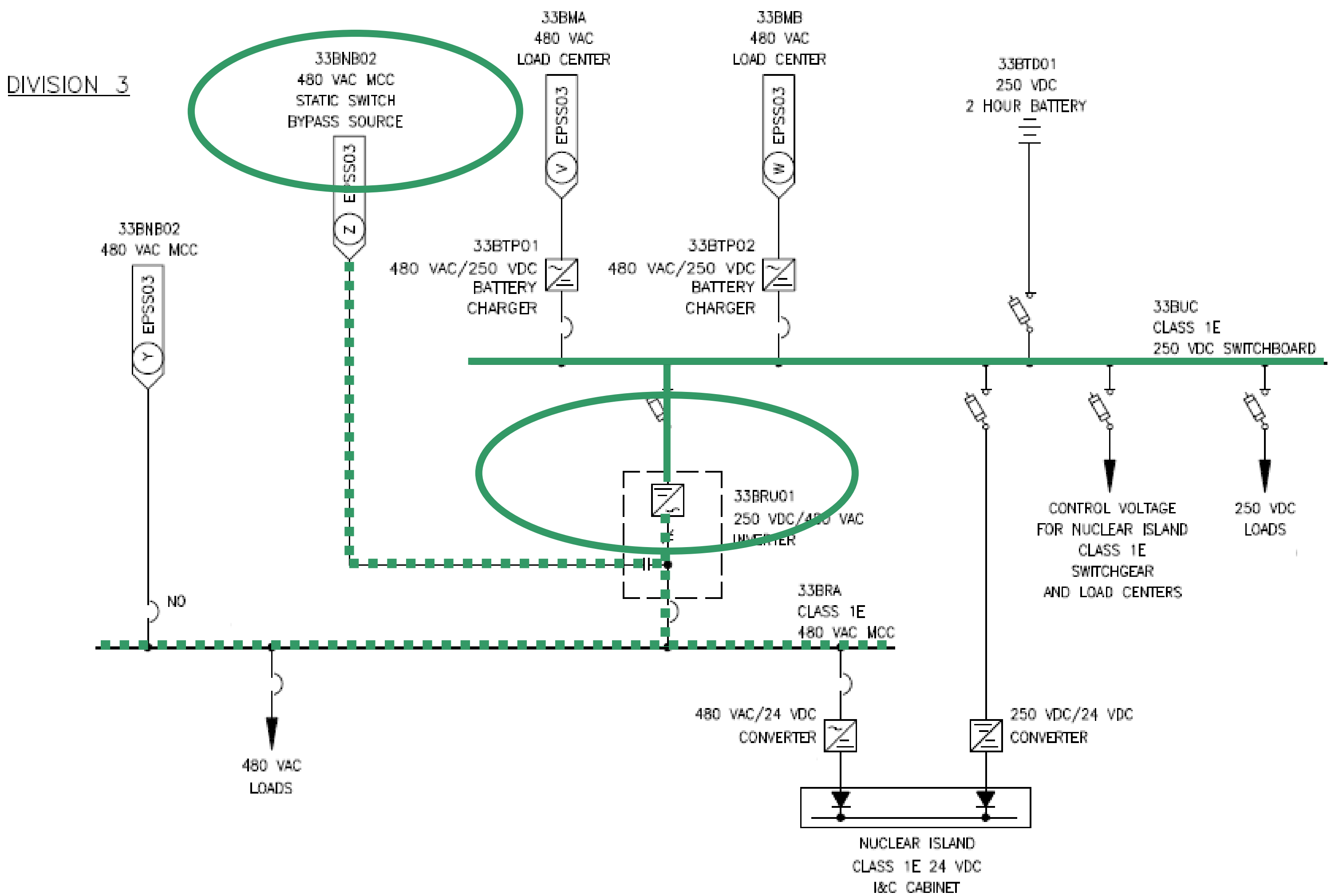
Class 1E Uninterruptible Power Supply



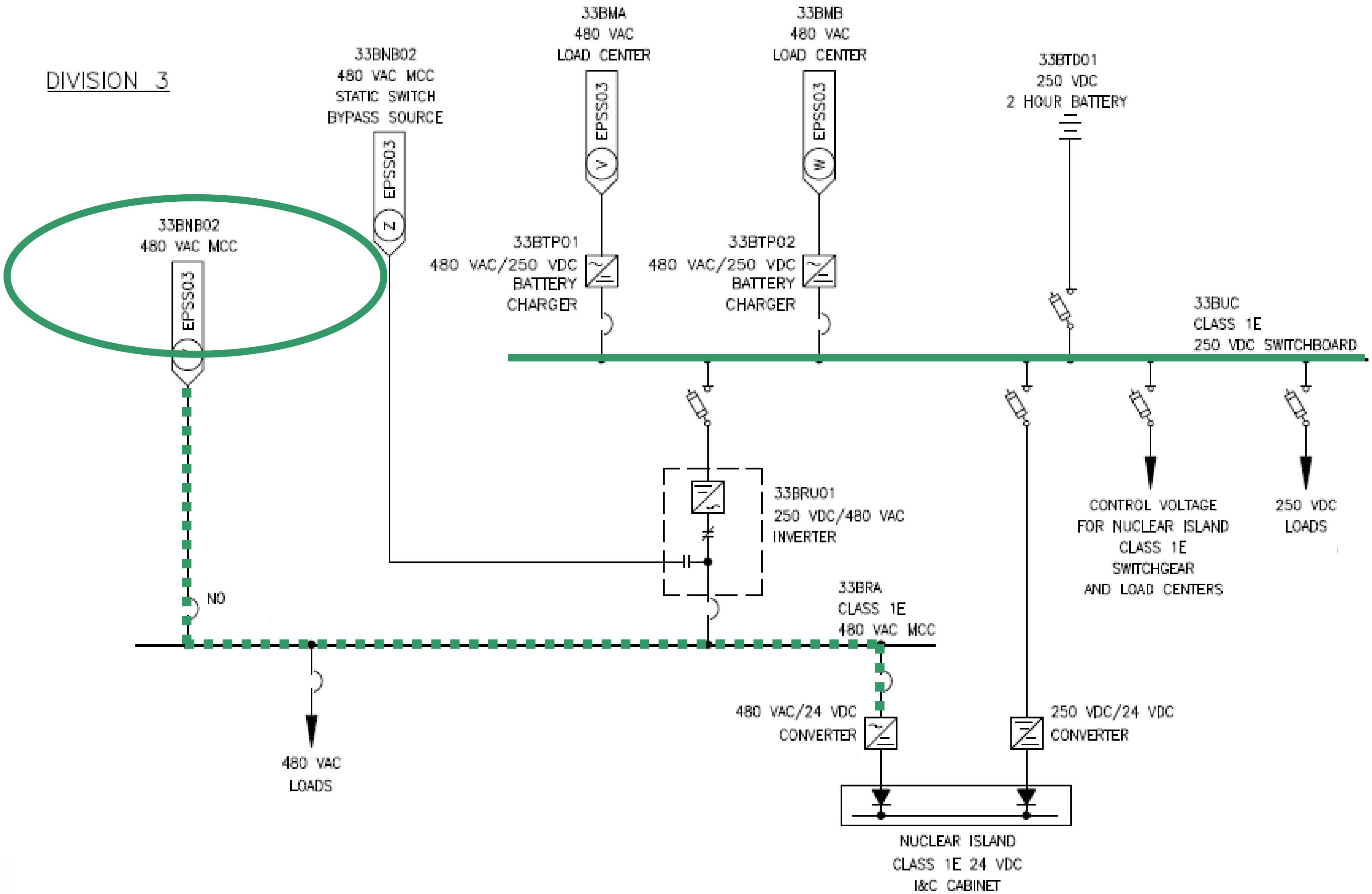
Chapter 8, Electric Power
8.3 Onsite Power System
Class 1E Uninterruptible Power Supply



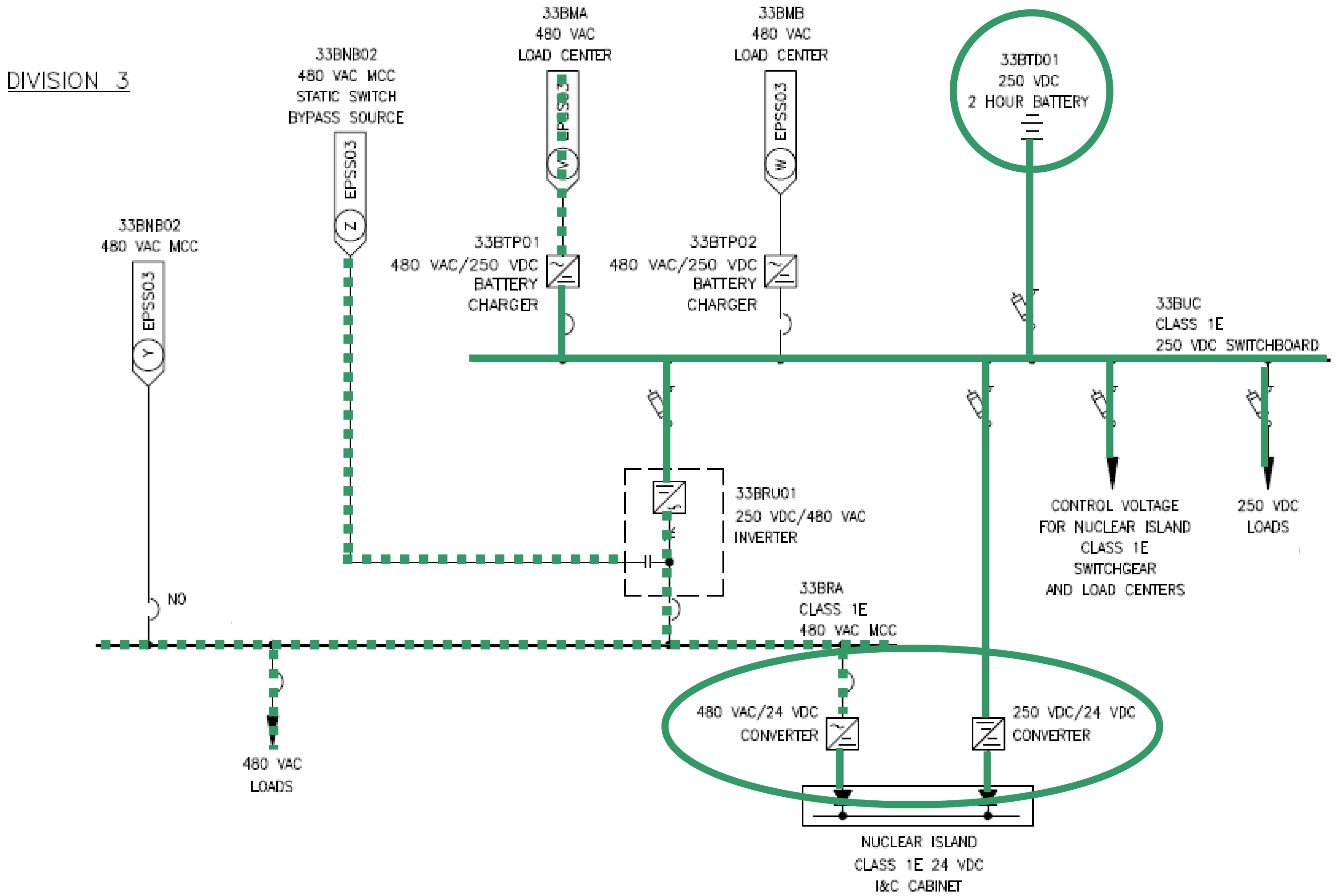
Chapter 8, Electric Power
8.3 Onsite Power System
Class 1E Uninterruptible Power Supply



Class 1E Uninterruptible Power Supply



Class 1E Uninterruptible Power Supply



Chapter 8, Electric Power
8.3 Onsite Power System
12UPS

- **12UPS Design Criteria – A two train system used to provide a source of uninterruptible power to loads for beyond design basis events. Example of loads powered from the 12UPS:**
  - **SBO controls**
  - **Severe Accident I&C**
  - **Severe Accident Depressurization Valves**
  - **Control Room Lighting**
  - **Outside Containment Isolation Valves**
- **Island Mode – the plant is designed for a loss of the grid with the main generator providing power to the house loads without a plant trip. Therefore, only the plant's main generator is powering the EATs and NATs.**

Chapter 8, Electric Power
8.4 Station Blackout

- **Alternate AC (AAC) source - two diesel generators**
- **Connected in Divisions 1&2 and 3&4 at 6.9 kV Buses**
- **Minimum SBODG output - 3900 kW**
- **Meets SBO Rule (10 CFR 50.63)**
  - **Diverse from EDGs**
    - Diverse engine models
    - Located in separate areas of the plant
    - SBODG air cooled vice EDG water cooled
    - No sharing of auxiliaries- engine cooling (radiator), control power, fuel systems
    - Available to the EPSS buses within 10 minutes of the onset of SBO

Chapter 8, Electric Power Summary

- **The U.S. EPR™ Electrical System Design:**
  - **Meets Regulatory Requirements**
  - **Protects the Health and Safety of the Public**
  - **Provides a Stable Electrical Supply for Normal Operations**
  - **Provides a Stable Electrical Supply for Effective Event Management**
  - **Is Evolutionary:**
    - The U.S. EPR™ Electrical Design Incorporates >30 Years of Industry Lessons Learned
    - Offsite Emergency Bus Transformer Feeds are Separated From Offsite Non-Safety Bus Transformer Feeds
      - No shared transformers between safety and non-safety loads
      - Non-safety loads not powered directly from the main generator, therefore no fast transfer scheme required if the reactor trips
    - Electrical Safety System Redundancy Increased
    - Alternate Feed Provides Required Power Supply Redundancy During EDG Maintenance

Backup Slides

Section 8.1

FSAR Revision 1 - Text

U.S. EPR FINAL SAFETY ANALYSIS REPORT

8.0 Electric Power

8.1 Introduction

8.1.1 Offsite Power Description

Offsite power to the U.S. EPR is provided by at least two utility transmission lines connected to the station switchyard. The power plant interfaces with the switchyard at the output of the main generator via the main step-up transformers and at the station auxiliary transformers.

The utility transmission system, location of rights-of-way, transmission lines and towers, and switchyard design and interconnections are site-specific. A COL applicant that references the U.S. EPR design certification will provide site-specific information describing the interface between the offsite transmission system and the nuclear unit, including switchyard interconnections.

During normal operation, the main generator connects to the switchyard via three single-phase step-up transformers to supply power to the transmission system. The plant electrical distribution system receives offsite power during normal plant operating modes, anticipated operational occurrences, and postulated accidents via five auxiliary transformers connected to the switchyard. The U.S. EPR design does not include the traditional unit auxiliary transformer that connects the plant electrical distribution system directly to the main generator output as the normal source during power operation. The preferred power supply (PPS) is the power supply from the transmission system to the Class 1E emergency power supply system (EPSS) which is preferred to provide power under accident and post-accident conditions. Two emergency auxiliary transformers (EAT) provide the PPS from the switchyard to the EPSS with no intervening non-Class 1E switchgear. Three normal auxiliary transformers (NAT) provide power from the switchyard to the non-Class 1E normal power supply system (NPSS).

Offsite power is described in depth in Section 8.2.

8.1.2 Onsite Power System Description

The EPSS distributes 6.9 kV and 480 Vac power to safety-related and select non-safety-related plant loads. There are four divisions of switchgear, load centers, motor control centers (MCC), standby power sources, and distribution system transformers that make up the EPSS as shown in Figure 8.3-2—Emergency Power Supply System Single Line Drawing. Each division includes a Class 1E emergency diesel generator (EDG), which is the standby power source to its particular division in the event of a power loss. Each division has the ability to connect to one of two non-safety-related station blackout diesel generators (SBODG) used as the alternate AC (AAC) source during station blackout (SBO) conditions. An alternate feed is provided from EPSS

RAI Response - Text

Section 8.1 RAIs

For Information Only

RAI Number	Submittal
08.01-01	009

RAI Text

Page 8.1-3 (8.1.3) of the FSAR states that "a COL applicant will identify site-specific loading differences that raise EDG or Class 1E battery loading, and demonstrate the electrical distribution system is adequately sized for the additional load." Regulatory Issue Summary (RIS)-2006-06 encourages the agency's design-centered review approach (DCRA) regarding DC and COL applications and describes the level of standardization of a particular design needed in order to make the DCRA effective. The RIS promotes the standardization of COL applications to facilitate the establishment of a predictable and consistent method for reviewing applications. The staff notes that only approximate sizing information for the main generator, EDG, and SBODG is given. It appears that the exact size for the above equipment is left for the Combined Operating License (COL) applicants to decide based on site specific information. COL applicants proposing different sizes for electrical equipment will require additional time which will impact their review schedules. The staff believes that all sizing information for the US-EPR certified design (CD) should be standardized. The staff has reviewed other standardized FSARs and found all adhering to the DCRA concept. All electrical equipment (main generator, EDG, battery and SBODG) sizes should be specified in EPR DC documentation (FSAR) and the decision should not be left to the COL applicants. In addition, all statements including the phrase "a COL applicant will identify site-specific loading differences…." should be amended to reflect this approach. Please fully delineate Areva's position on the standardized equipment sizing issue.

Response Text

The electrical equipment sizes [main generator, emergency diesel generators (EDG), and station blackout diesel generators (SBODG)] were sized and analyzed using the electrical transient analyzer program (ETAP) to provide the safety-related standby power source function (for EDG) plus margin, alternate AC source function (for SBODG) plus margin, and plant output capacity (for main generator). The actual rated size of the main generator, EDG, and SBODG is dependent on which manufacturer is selected to provide the equipment and the nominal values of the associated equipment. The equipment sizes are indicated [e.g., "SBODG size of 3900 kW (or greater)" and "verify an EDG output of 9500 kW or greater"], to provide a minimum equipment size to satisfy the function of the equipment, plus margin, but allows for slight differences in the size of as-procured equipment.
The COLA information item verifies that any additional site-specific EDG loads do not exceed the minimum required size for the EDG of 9500 kW plus the 10 percent margin stated in Regulatory Guide 1.9. The required size for the SBODG is 3900 kW and the EDG is 9500 kW. The final ratings of the equipment may be slightly higher as stated above. The main generator output is approximately 2000 MVA but actual nameplate values depend on which turbine-generator manufacturer is selected. The ETAP analysis used 2015 MVA for assumed main generator output and the main step up transformers are sized for 2130 MVA as described in FSAR Table 8.3-1—Onsite AC Power System Component Data Nominal Values.
The Class 1E battery size is listed in FSAR Table 8.3-11—Onsite DC Power System Component Data Nominal Values. The COLA item verifies that any additional site-specific Class 1E battery loads do not exceed the required size for the Class 1E batteries plus margin as defined in FSAR Table 8.3-11.

FSAR Impact

The FSAR will not be changed as a result of this question.

Section 8.2

FSAR Revision 1 - Text

8.2 Offsite Power System

8.2.1 Description

8.2.1.1 Offsite Power

The offsite power system provides power from the transmission system, via the station switchyard, to the plant Class 1E and non-Class 1E electrical distribution system. The offsite power system includes all transmission lines connected to the switchyard, the switchyard equipment (overhead buses, circuit breakers, disconnect air switches), auxiliary transformers, and ends at the input terminals of the switchgear circuit breakers. The preferred power supply (PPS) is the offsite power from the transmission system to the Class 1E emergency power supply system (EPSS) that is preferred to provide power under accident and post-accident conditions. The offsite transmission system and connections to the station switchyard are site-specific. A COL applicant that references the U.S. EPR design certification will provide site-specific information regarding the offsite transmission system and connections to the station switchyard.

The switchyard has connections to at least two transmission lines. The normally energized transmission lines are physically independent circuits that minimize the likelihood of their simultaneous failure under operating and environmental conditions and postulated events, including transmission tower or transmission line failure. These lines do not cross, and no other transmission lines cross above these two lines. Each offsite power circuit is sized to supply the station safety-related and non-safety-related loads during normal and abnormal operation.

The PPS supplies the station Class 1E EPSS buses from two independent overhead lines between the switchyard and the station transformer area via two emergency auxiliary transformers (EAT). The station remains connected to the offsite power sources during normal plant operation regardless of main generator status, without transferring buses or power sources during startup, full power operation, or shutdown. Each PPS circuit is normally in service through its respective EAT.

Three additional overhead lines provide power to three normal auxiliary transformers (NAT) for the station non-Class 1E normal power supply system (NPSS) buses.

Each auxiliary transformer is provided with two on-load tap changers to maintain the supplied bus voltage at the nominal value during transmission system voltage fluctuations, or voltage changes as a result of changes in bus loading. The reference voltage for the on-load tap changer operation is provided by voltage transformers at the respective bus to which the secondary winding is connected. Momentary bus voltage transients (e.g., motor starting) do not result in tap changers affecting bus voltage due to the short nature of the voltage transient. The voltage regulating range is based on the results of the load flow/voltage regulation studies described in Section 8.3.1.3.1.

RAI Response - Text

Section 8.2 RAIs

For Information Only

RAI Number	Submittal
08.02-01	009

RAI Text

Page 8.2-2 (8.2.1.1) of the FSAR states that "The U.S. EPR does not use an automatic load dispatch system, which eliminates any interference with safety-related actions that may be required of the protection system described in Section 7.1.1.3.1." Explain whether the above sentence is relevant in this section or consider revising if necessary.

Response Text

SRP Section 8.2.III.9 indicates "the review of any automatic TSO action should ascertain that TSO actions (including normal and postulated failure modes of operation) will not interfere with safety actions that may be required of the reactor protection system. This system should also be reviewed to ensure that no failure mode of the TSO system will cause an incident at the generating station which would require protective action." Tier 2 Section 8.2.1.1 provides the description of the offsite power system and the plant interface with offsite power. This sentence indicates there is not an automatic TSO action that will interact with the reactor protection system.

FSAR Impact

The FSAR will not be changed as a result of this question.

Section 8.3

FSAR Revision 1 - Text

8.3 Onsite Power System

8.3.1 Alternating Current Power Systems

8.3.1.1 Description

The main generator provides power through the station switchyard to the transmission system via an isolated phase bus (IPB) system and three single-phase main step-up transformers (MSU). Incoming power to the onsite AC power system is from the station switchyard during all modes of plant operation, through the emergency and normal auxiliary transformers to the Class 1E and non-Class 1E distribution systems respectively.

The main generator is connected to the switchyard via two circuit breakers in the switchyard. Either breaker enables the generator to provide power to the transmission system. During main generator startup and synchronization with the grid, a generator automatic synchronizer is used in combination with an independent synchrocheck permissive relay, which provides a closing signal to the main generator breaker.

Prior to main generator synchronization with the transmission system, the plant loads are fed by the transmission system through the switchyard. The main generator circuit breakers in the switchyard are open at this time. The switchyard and offsite power supply arrangement allows station loads to remain powered from the same source during all plant operating modes and eliminates the need for bus transfers during plant startup or shutdown.

Main generator protection is provided by a primary and backup protection scheme. Protective device actuation trips the main generator output breakers in the switchyard, trips the generator excitation and initiates a turbine trip. Main generator protection includes stator overcurrent, ground fault and reverse power.

The MSU protection detects faults and initiates protection actions to minimize any potential damage to an MSU, while minimizing impact to the electrical distribution system. Protective devices installed for the protection of the MSU include transformer bank differential current, ground fault overcurrent, phase overcurrent and sudden pressure relays. Activation of an MSU protection device results in a turbine generator trip and a separation of the main generator from the grid by tripping the main generator breakers in the switchyard. The onsite electrical distribution continues to be powered from offsite through the switchyard with no power interruption to the onsite power distribution system. No offsite power source transfer is required during this transient.

If the offsite transmission system has a fault that results in a loss of power from the transmission system, the main generator continues to provide power to the plant loads from the switchyard via the normal and emergency auxiliary transformers. The main

RAI Response - Text

Section 8.3 RAIs

For Information Only

RAI Number	Submittal
08.03.01-01	011, Suppl. 2

RAI Text

Page 8.3-3 (8.3.1.1.1) of the FSAR states that "a loss of voltage at one of 6.9 kV (BDA) buses initiates an automatic fast transfer of the offsite power source, maintaining offsite power to all four divisions by switching the affected bus power supply to the unaffected EAT. The fast transfer minimizes voltage decay and frequency difference to limit motor torque during the transfer, thus minimizing equipment degradation." Explain how the automatic fast transfer scheme works and how the scheme prevents transfer into a faulted bus. Elaborate on whether any single failure vulnerability exists with the transfer scheme between the motive (AC) and control power (DC) within the affected divisions. Is the same transfer scheme used for NPSS?

Response Text

The emergency power supply system (EPSS) fast transfer is a non-safety-related bus transfer that improves the reliability of offsite power by initiating a transfer in specific fault conditions that would otherwise result in the loss of offsite power (LOOP) to EPSS switchgear. A failure in the fast transfer scheme does not affect the capability of the Class 1E emergency diesel generators (EDG) to perform their safety function of supplying electrical power to the EPSS buses in a loss of voltage condition. The offsite power system is designed to remain on the preferred source, offsite power, whenever possible. Otherwise, depending on the postulated failures, the buses will ultimately revert to their safety-related power source, the EDGs.

The single point vulnerabilities that can affect the fast transfer are limited to those that will affect a single division. These potential failures beyond the initiating event (emergency auxiliary transformer (EAT) failure) are no different for the fast transfer logic than for a residual voltage bus transfer. For example, the failure of a circuit breaker in the transfer scheme (either normal or alternate) to a BDA bus will limit the impact to that specific division. Additionally, the DC control power that supports the transfer (control power for circuit breaker tripping coils and transfer supervision) is supplied by the Class 1E uninterruptible power supply system of the respective division; therefore, a failure in the control power function is limited to the affected division. In the case of a divisional DC system failure, that division EDG may also be affected. In the case of an offsite power supply breaker failure to close unrelated to a divisional DC system failure, that division EDG will start and re-energize the bus.

In each of these conditions where an additional failure beyond the initiating event results in the loss of power to an EPSS division, the remaining three divisions are capable of maintaining plant safe operations (as limited by applicable technical specification required actions) and mitigating design basis events.

A fast transfer of the EPSS buses to an alternate emergency auxiliary transformer (EAT) is initiated by a fault related to the normal EAT supply to the bus. The transformer protection (e.g., transformer differential current) that will isolate the faulted transformer also initiates the fast transfer. The dead bus time, or the time from contact parting to contact touching of the opening and closing circuit breakers, is typically limited to three to five cycles. Synchronism of the two sources prior to the fast transfer is verified by a synch check relay, which verifies that the phase angle between the motor bus (e.g., BDA) voltage and the alternate source voltage is within acceptable limits prior to closing the alternate source breaker. This synch check function is accomplished with a two-out-of-three logic scheme that prevents a single failure in the synch check function from permitting a bus transfer to an out-of-phase source.

A bus transfer example illustrates how the fast bus transfer scheme prevents either transfer of a faulted bus to an unaffected bus or transfer of an unaffected bus onto a faulted bus. The example will also demonstrate the limit of plant impact if component failure allows the transfer with unacceptable conditions. U.S. EPR FSAR Tier 2, Figure 8.3-2—Emergency Power Supply System Single Line Drawing, Sheet 1 of 3 illustrates the following description. A fault on EAT supply 30BDT01, EPSS buses 31BDA and 33BDA normal supply will initiate the transfer of those buses to the alternate EAT supply, 30BDT02. The transfer involves opening the normal supply circuit breaker and closing the alternate supply circuit breaker using the previously described fast transfer scheme. Because the transfer is initiated by a transformer fault, a faulted bus will not be transferred. The bus is transferred onto the alternate EAT secondary winding, which verifies that the bus is not transferred onto a bus that has the potential to be faulted. If there is a bus (e.g., BDA) fault, the bus protection will trip open and lockout any source breaker associated with affected bus. This protection will prevent transfer of a faulted bus onto a transformer secondary winding that is shared with another bus. For example, a 32BDA bus fault will trip and lockout the source breakers associated with 32BDA (normal and alternate offsite power source and EDG output circuit breakers). A transfer of 31BDA (shares 30BDT02 X winding) would be unaffected by the fault on 32BDA since 32BDA source breakers are locked out.

Because the auxiliary transformer protection is provided by diverse actuations, a single failure in a transformer protection device will not prevent the protection of the transformer. For example, a transformer internal fault will likely actuate several protection relays (e.g., sudden pressure, overcurrent, differential current). Single failure of one of the detection and actuation devices will not prevent the isolation of the transformer by the remaining

Section 8.4

FSAR Revision 1 - Text

8.4 Station Blackout

The term station blackout (SBO) refers to a complete loss of alternating current (AC) electric power to the non-safety-related and safety-related switchgear buses. An SBO involves a loss of the offsite electric power system (preferred power system) occurring at the same time the emergency diesel generators (EDG) are unavailable. An SBO does not include loss of available AC power to buses fed by station batteries through inverters or by alternate alternating current (AAC) sources specifically provided for SBO mitigation.

8.4.1 Description

The U.S. EPR includes an AAC source that has been designed in accordance with 10 CFR 50.63 and RG 1.155. NUMARC 87-00 (Reference 1) was used for clarification, as permitted by RG 1.155. Two separate and independent non-safety-related station blackout diesel generators (SBODG) are provided to mitigate a postulated SBO. The SBODGs have the capacity and capability to bring the plant to, and maintain the power plant in, a non-design basis accident (non-DBA) safe shutdown condition without any support systems powered from the preferred power supply (offsite grid) or emergency power supply system (EPSS). Safe shutdown (non-DBA) means bringing the plant to those shutdown conditions specified in the U.S. EPR Technical Specifications as "hot standby."

8.4.1.1 Station Blackout Diesel Generators

The SBODGs are located in separate areas of the Switchgear Building. An electrical system failure modes and effects analysis is illustrated in Table 8.3-9—Onsite AC Power System Failure Modes and Effects Analysis. The SBODGs do not share control power, heating, ventilation and air conditioning (HVAC), engine cooling, or fuel systems with the EDGs. Considering the support system independence and the failure modes listed in Table 8.3-9, there are no weather-related events or single active failures that can disable the SBODGs and EDGs simultaneously. For the purposes of the failure modes and effects analysis, failure of an SBODG is equivalent to a failure of switchgear bus 31BBH or 32BBH. Failure of 31BBH or 32BBH is addressed in Table 8.3-9.

The major system loads the SBODGs provide power to during SBO conditions are:

- The division 1 and division 4 emergency feedwater (EFW) pumps.
- HVAC systems to maintain main control room (MCR) habitability and SBO equipment environments.
- Selected instrumentation and controls (I&C) systems.
- MCR lighting.

RAI Response - Text

Section 8.4 RAIs

For Information Only

RAI Number	Submittal
08.04-01	011

RAI Text

Page 8.4-1 (8.4.1) of the FSAR states that the "SBODGs have the capacity and capability to bring the plant to and maintain the power plant in a non-design basis accident (non-DBA) safe shutdown condition without any support systems powered from the preferred power supply (offsite grid) or EPSS. Safe shutdown (non-DBA) means bringing the plant to those shutdown conditions specified in the U.S. EPR technical specifications as hot standby." However, page 21 of SECY 94-084 recommends the preferred method of demonstrating compliance with 10 CFR 50.63 for evolutionary design to be a spare full-capacity alternate ac (AAC) power source of a diverse design and that the AAC power source powers a larger complement of shutdown equipment to bring the plant to cold shutdown (not hot standby). Based on the above guidance, the AAC power source should bring the plant to a cold shutdown and the size of AAC should be the same size as an EDG (9500 kW) of US-EPR. The proposed SBODG for US-EPR CD provides 3900 kW which would bring the plant only to hot standby. Explain how EPR plans to satisfy the SECY guidance with regard sizing of the SBODG.

Response Text

Station Blackout End State

It is neither required nor desirable to bring the plant to cold shutdown during a station blackout event. SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs," March 28, 1994, is for passive plant designs and therefore does not appear to be directly applicable to the U.S. EPR. However, at page 6 of SECY-90-016, "Evolutionary Light Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements," June 26, 1990, it is stated, "The staff believes that the preferred method of demonstrating compliance with 10 CFR 50.63 is through the installation of a spare (full capacity) alternate ac power source of diverse design that is consistent with the guidance in Regulatory Guide 1.155, and is capable of powering at least one complete set of normal safe shutdown loads." This statement is in support of a staff request that the Commission approve imposition of an alternate alternating current (AC) source for evolutionary advanced light-water reactors (ALWR). By letter dated June 26, 1990, the Commission approved in part and disapproved in part the staff's recommendations in SECY-90-16. With respect to station blackout, item II.C (page 3) states, "The Commission (with all Commissioners agreeing) has approved the staff's position that the evolutionary ALWRs have an alternate ac power source of diverse design capable of powering at least one complete set of normal shutdown loads." This statement does not identify the required end state operating mode.

The definition, "alternate ac source" contained in 10 CFR 50.2 states that an alternate AC source "Has sufficient capacity and reliability for operation of all systems required for coping with station blackout and for the time required to bring and maintain the plant in safe shutdown," and provides that "Safe shutdown (non-design basis accident (non-DBA)) for station blackout means bringing the plant to those shutdown conditions addressed in plant technical specifications as Hot Standby or Hot Shutdown, as appropriate (plants have the option of maintaining the RCS at normal operating temperatures or at reduced temperatures)."

Regulatory Guide 1.155, "Station Blackout," provides a method for determining the required coping duration. For the U.S. EPR, this duration is no more than 8 hours, and may be less depending on the result of certain site-specific "factors" defined in Regulatory Guide 1.155. Regulatory Guide 1.155 and the NRC correspondence included in Appendix K to NUMARC 87-00, Revision 1, provide NRC endorsement of NUMARC 87-00, Revision 1, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors. NUMARC 87-00, Revision 1, Appendix I Question I.8.119 also defines safe shutdown as "hot shutdown or hot standby as appropriate…"

As stated in U.S. EPR FSAR Tier 2 Section 8.4.2.6.1, the U.S. EPR design envelopes an eight hour coping duration for the worst case site conditions. This duration was determined in accordance with Regulatory Guide 1.155, Table 2, "Acceptable Station Blackout Duration Capability," and NUMARC 87-00, Revision 1, Section 3, "Required Coping Duration Category." As defined by 10 CFR 50.2, "Station Blackout" means a complete loss of alternating current power to the essential and nonessential switchgear buses. Therefore, the Reactor Coolant Pumps are unavailable during a station blackout. The cooldown rate during the resulting natural circulation cooldown is greatly reduced as compared to a normal cooldown, so that cold shutdown is not achievable during an eight-hour station blackout event. Even if a cooldown to cold shutdown was possible, this would be undesirable, because it would cause shrinkage of the reactor coolant system inventory.

Alternate AC Source (Station Blackout Diesel Generator) Size

The alternate AC source and emergency diesel generators (EDG) have different design bases, and therefore the nominal sizes are different.

Referring again to 10 CFR 50.2, the alternate AC source is defined to have sufficient capacity for operation of all systems required for coping with station blackout and for the time required to bring and maintain the plant in safe shutdown (non-design basis accident). Conversely, the EDGs are specifically designed to power design basis

U.S. EPR Electrical Distribution System (EDS), Model Development & System Analyses

Dr. Zia Salami, Ph.D.
Advisory Electrical Engineer
November 03, 2009

EDS Model Development and System Analyses

- Objective
- Approach and methodology
- System evaluation and summary of results
- Conclusion

EDS Model Development and System Analyses

Objective:

- **To analyze U.S. EPR, EDS design:**
  - To verify the distribution system is adequate and can perform its required function during the various loading scenarios, configurations and design basis accidents considering worst case offsite and/or onsite power source configuration, based on the following major criteria:
    - Equipment (e.g., EDG/SBODG, transformers, buses, circuit breakers, cables):
      - Continuous and short-time (momentary) loadings
      - Short-circuit capabilities and ratings
      - Acceptable continuous and momentary voltages, current, and power flow capabilities
      - Availability (standard)

EDS Model Development and System Analyses

▶ Approach and Methodology

Software Platform

- Electrical Transient Analyzer Program (ETAP), by Operation Technology, Inc (OTI), selected as main electrical analyzer tool within AREVA NP

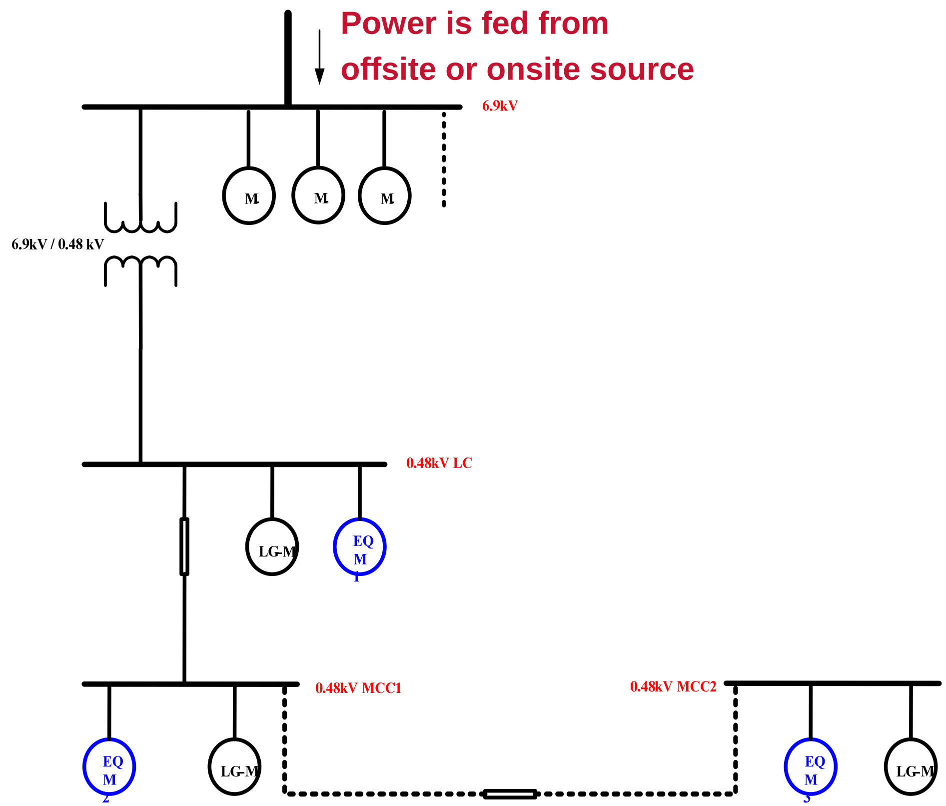
Model Development

- Define conservative and bounding modeling methodology and assumptions
- Develop EDS ETAP single line diagram
- Develop plant configurations and mode of operations, such as:
  - Power from grid (offsite power)
  - Power from emergency diesel generator (EDG) (onsite emergency power)
  - Power from station blackout diesel generators (SBODG) (onsite alternate AC source)
  - Power from DC (battery) source

EDS Model Development and System Analyses

▶ Example of modeling approach for low voltage system:

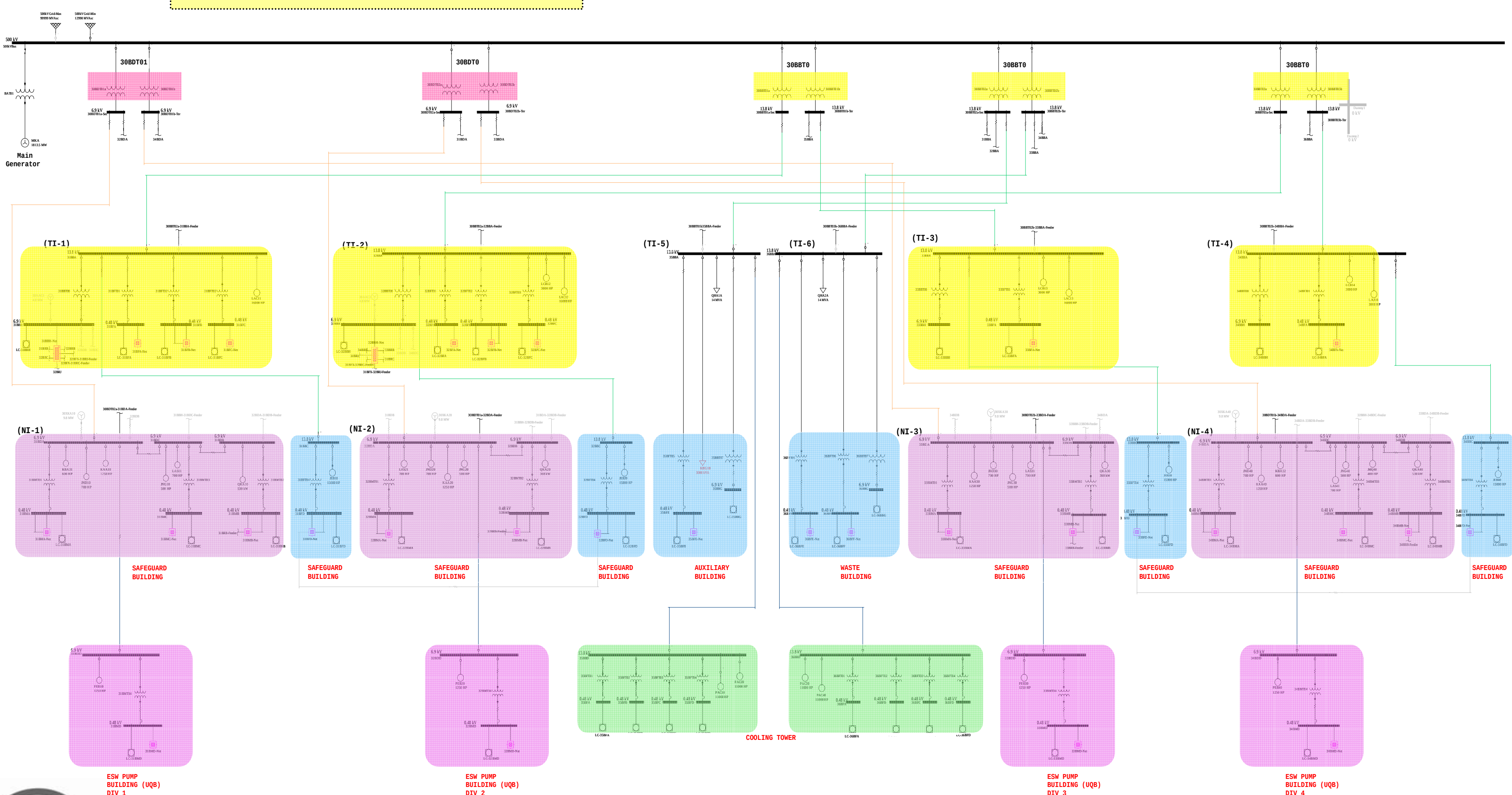
- **Medium Voltage (MV) System**
  - Modeling the entire MV loads for both safety and non-safety system
- **Low Voltage (LV) System:**
  - Equivalent load for both safety and non-safety system
  - Adjust total LV loads equals to supply transformer rating
  - Largest allowable motor load is connected to load center (LC) and motor control center (MCC)



EDS Model Development and System Analyses

U.S. EPR ETAP SLD, From Grid

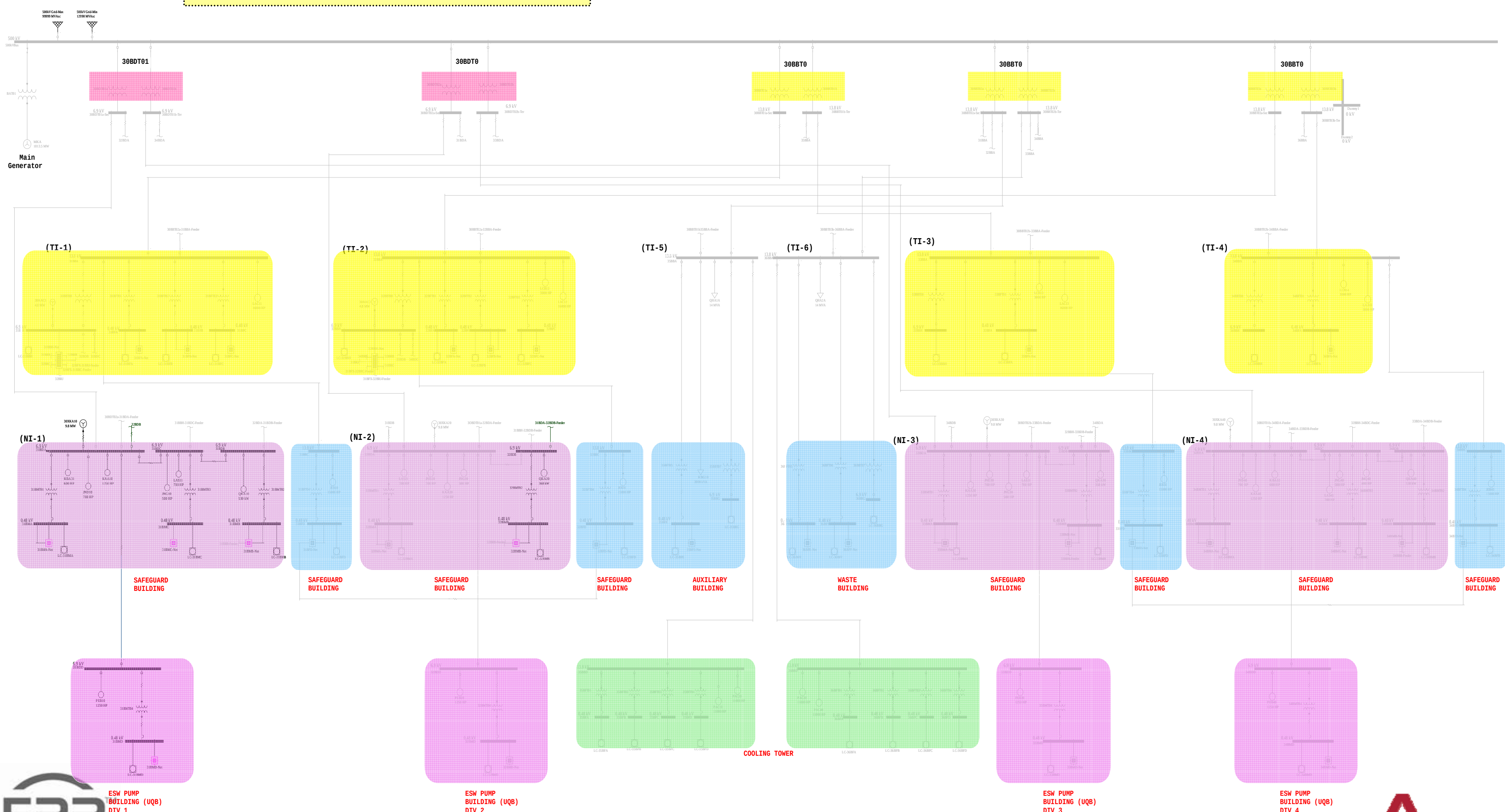
US EPR - ETAP SLD



EDS Model Development and System Analyses

U.S. EPR ETAP SLD, From EDG

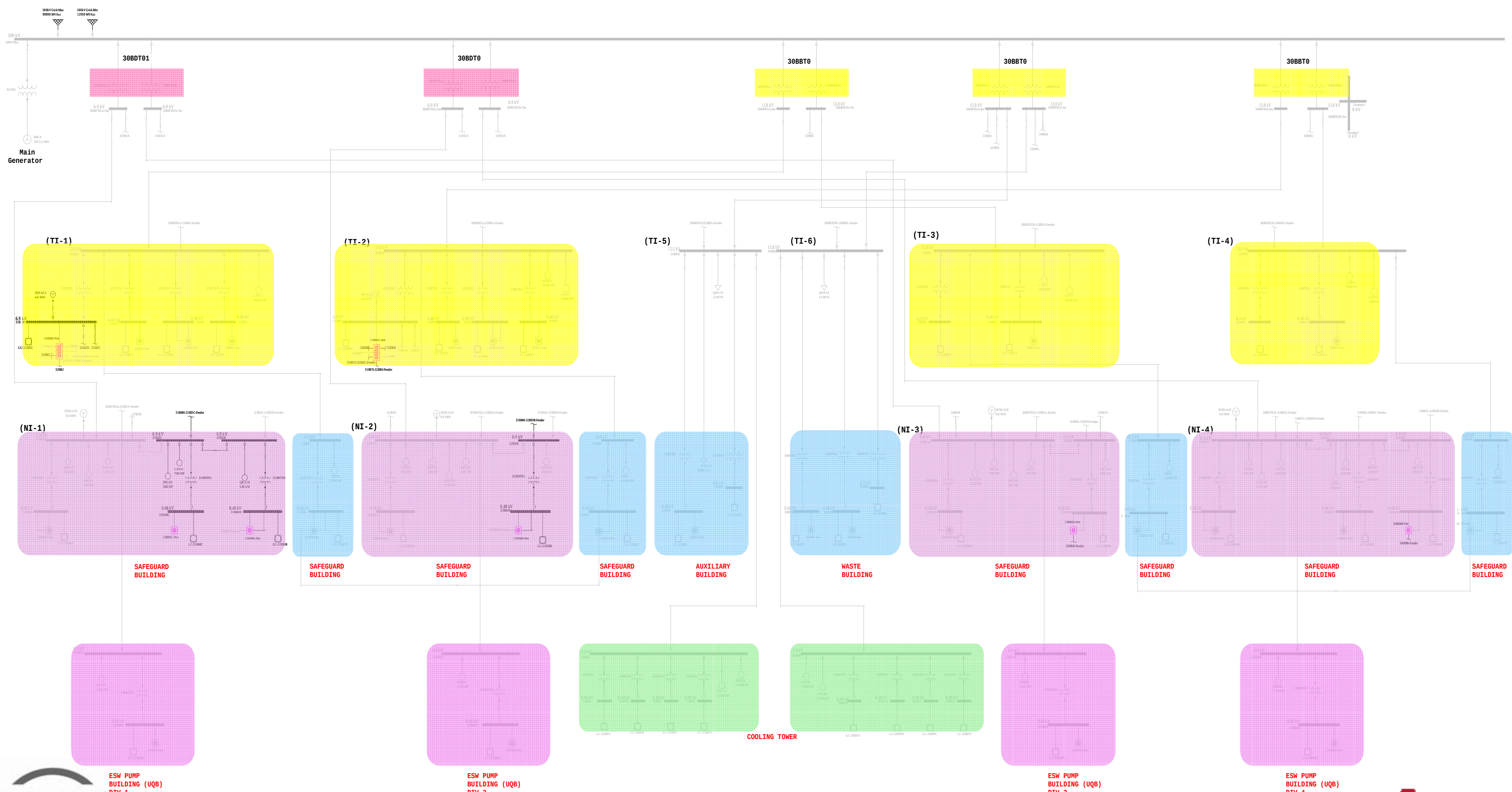
US EPR - ETAP SLD



EDS Model Development and System Analyses

U.S. EPR ETAP SLD, From SBODG

US EPR - ETAP SLD



EDS Model Development and System Analyses

- **Approach and Methodology (Cont.):**
  - **Perform System Study and Simulation Such As:**
    - Load Flow Study
    - Short-Circuit (Fault) Study
    - Motor Starting Study
    - Equipment Sizing Study

EDS Model Development and System Analyses

- **System Evaluation and Summary of Results**
  - **Study Results Against Acceptance Criteria (Iterative Process)**
    - Equipment (e.g., EDG/SBODG, transformers, buses, circuit breakers, and cables) are within their loading requirements
    - Equipment are within their short-circuit capabilities
    - Equipment are within acceptable continuous and momentary, voltage, current, and power ratings
    - Distribution system equipment sizes are available based on standard equipment availability
  - **U.S. EPR EDS design verified to be adequate**

EDS Model Development and System Analyses

- **Conclusion:**
  - **The U.S. EPR™ Electrical Distribution System:**
    - Adequately supports the supplied equipment during performance of the design functions (safety or non-safety)

- **QUESTIONS?**

Presentation to the ACRS Subcommittee

AREVA U.S. EPR Design Certification Application Review

Safety Evaluation Report

CHAPTER 8: ELECTRIC POWER

November 3, 2009

Staff Review Team

- **Technical Staff**
  - **Peter Kang**
    Electrical Engineering Branch

- **Project Managers**
  - **Getachew Tesfaye**
  - **James Steckel**

Overview of Staff's Review

SRP Section/Application Section		Number of RAI Questions	Number of SE Open Questions
8.1	Introduction	4	0
8.2	Offsite Power System	7	0
8.3.1	Alternating Current (AC) Power Systems (Onsite)	24	0
8.3.2	Direct Current (DC) Power Systems (Onsite)	5	0
8.4	Station Blackout	9	0
Totals		49	0

Technical Topics of Interest

Section 8.2 - Offsite Power System

United States Nuclear Regulatory Commission
Protecting People and the Environment

Inaccessible Power Cables Installed in Duct Bank, or Underground

- RAI
  - COL applicants should be responsible for developing site-specific testing programs per Generic Letter 2007-01 for inaccessible power cables installed in duct bank, or under underground
- Response
  - Agreed to add a COL item describing need for inspection, testing, and monitoring programs for the detection of the degraded inaccessible underground power cables
  - Cited use of the following potential testing methods: partial discharge testing, time domain reflectometry, dissipation factor testing, or very low frequency ac testing
- Result
  - Staff has no further questions regarding cable testing program

Technical Topics of Interest

Section 8.3 - Onsite Power System

Alternate feed Configurations and EDG Technical Specification (TS)

- RAI
  - Divisional independence
  - Single failure requirement and risk insights
  - TS provision allows the plant to operate for 120 days
- Response
  - Provided technical details of divisional independence, and demonstrated no single failure vulnerability exists under various alternate feed scenarios
  - Stated no significant change in risk
  - Stated that the lineup does not introduce any new safety concerns
- Result
  - Staff has no further questions regarding alternate feed configurations

BTP 8-6 Adequacy of Station Electric Distribution System Voltages

- RAI
  - Protect the safety-related equipment from degraded grid voltage conditions
  - Verify the voltage analysis by actual bus voltage measurements
  - Evaluate whether different degraded grid setpoints are needed for any alternate feed configurations
- Response
  - COL applicant will perform this analysis to:
    - Determine the site-specific degraded grid setpoints based on the offsite power system grid (TS item)
    - Conduct verification during the plant initial testing program
    - Demonstrate no changes to degraded grid settings for any alternate feed configurations
- Result
  - Staff has no further questions on degraded voltage protection

Technical Topics of Interest
Section 8.4 Station Blackout (SBO)

Sizing of SBO diesel generators (SBODGs)

- RAI
  - SECY 91-078 recommended that new reactors meet Electric Power Research Institute (EPRI) Utility Requirements Document recommendation that a large combustion turbine as an AAC power source be capable of powering at least one complete set of loads to cold shutdown
- Response
  - Two SBODGs will be used as an AAC power source for U.S. EPR design
  - Cold shutdown not required as the desired end state operating mode
- Result
  - Staff has no further questions regarding the sizing of SBODGs

Staff Findings

The U.S. EPR FSAR Provides:

- Sufficient information about offsite power system interrelationships among the nuclear unit, utility switchyard, and interconnection grids to assist the COL applicant

- Sufficient information about the onsite power system to mitigate design-basis events, given a loss of offsite power system and a single failure in the onsite power system

- Necessary analyses to determine capability to withstand and recover from an SBO event of specified 8 hour duration

Acronyms

- ac – alternating current
- AAC – alternate ac source
- COL – combined license
- EDG – emergency diesel generators
- EPRI – Electric Power Research Institute
- RAI – request for additional information
- SBO – station blackout
- SBODGs – station blackout diesel generators
- SECY – Secretary of the Commission
- TS – technical specification

AREVA NP Inc.

Presentation to ACRS

U.S. EPR Subcommittee

Design Certification Application
FSAR Tier 2 Chapter 2

Chapter 2, Site Characteristics: Chapter Topics

- Geography and Demography
- Nearby industrial, transportation, and military facilities
- Meteorology
- Hydrologic engineering
- Geology, seismology and geotechnical engineering

Chapter 2, Site Characteristics: Supplemental Information

2.0 Site Characteristics

- **U.S. EPR Design**
  - **Based on a set of conservatively established site characteristics, which represent more demanding site conditions than normally expected for most U.S. nuclear power plant sites**
  - **A COL applicant that references the U.S. EPR design certification will compare site-specific data to the design parameter data in Tier 2 Table 2.1-1**
    - If the data for the site is within the assumed design data and characteristics in Table 2.1-1, then the U.S. EPR standard design is bounding
    - If the data for the site is outside the bounds of the assumed design data and characteristics in Table 2.1-1, the COL applicant will confirm that the U.S. EPR design meets any additional requirements that may be imposed by the more limiting site-specific design parameter data or characteristics

Chapter 2, Site Characteristics: Supplemental Information

2.1 Geography and demography

2.1.1 Site location and Description - COL Applicant

- Specific location by longitude and latitude, Universal Transverse Mercator (UTM) coordinates, and political subdivisions; the site's relative location with respect to natural and man-made features of the area such as highways, railways, and waterways; and local population distribution
- A map of the site area of suitable scale showing relevant features such as the plant property lines, site and exclusion area boundaries (EAB), location and orientation of principal plant structures within the site area, and highways, railways and waterways that traverse or are adjacent to the site.

2.1.2 Exclusion Area Authority and Control - COL Applicant

- Define the authority and activities within the exclusion area

2.1.3 Population Distribution - COL Applicant

- Describe the population in the site vicinity

Chapter 2, Site Characteristics: Supplemental Information

2.2 Nearby industrial, transportation, and military facilities

- Robust design that can withstand a range of potential external hazards
- COL applicant will provide related site-specific information

2.2.1 Location and routes – COL Applicant

- COL applicant will provide related site-specific information on the location and routes associated with these facilities

2.2.2 Descriptions – COL Applicant

- COL applicant will provide related site-specific information which describes the primary function of each external facility and the nature of the hazard it presents

2.2.3 Evaluation of potential accidents – COL Applicant

- COL applicant will provide information concerning site specific evaluations pertaining to nearby industrial, transportation, and military facilities
- COL applicant will reconcile the site-specific hazards with the design

Chapter 2, Site Characteristics: Supplemental Information

2.3 Meteorology

"The U.S. EPR design is based on meteorological parameters (e.g., air temperature extremes, humidity, precipitation such as rainfall, snow and ice, maximum wind speeds, tornado wind speeds, and atmospheric stability characteristics) provided in Section 2.1, Table 2.1-1—U.S. EPR Site Design Envelope."

"If a COL applicant that references the U.S. EPR design certification identifies site-specific meteorology values outside the range of the design parameters in Table 2.1-1, then the COL applicant will demonstrate the acceptability of the site-specific values in the appropriate sections of the Combined License application."

Chapter 2, Site Characteristics: Supplemental Information

2.3 Meteorology (Cont'd)

2.3.1 Regional climatology – COL Applicant

- COL applicant will provide related site-specific characteristics for regional climatology

2.3.2 Local meteorology – COL Applicant

- COL applicant will provide related site-specific characteristics for local meteorology

2.3.3 Onsite meteorological measurement program – COL Applicant

- COL applicant will provide the site-specific, onsite meteorological measurement program

Chapter 2, Site Characteristics: Supplemental Information

2.3 Meteorology (Cont'd)

2.3.4 Short-term atmospheric dispersion estimates for accident releases – COL Applicant

- Atmospheric dispersion factors (χ/Q values) considered to be representative of potential future nuclear plant sites in the U.S. were used to calculate the consequences from postulated accidental releases
- COL applicant will confirm that site-specific χ/Q values are bounded by those specified by the U.S. EPR
- For site-specific χ/Q values that exceed the U.S. EPR values, the COL applicant will demonstrate that the radiological consequences meet applicable dose limits

2.3.5 Long-term atmospheric dispersion estimates for routine releases – COL Applicant

- An atmospheric dispersion factor considered to be representative of potential future nuclear plant sites in the U.S. was used to calculate the consequences from postulated normal effluent releases
- COL applicant will confirm that the site-specific annual average χ/Q values are bounded by the U.S. EPR value
- For site-specific χ/Q values that exceed the U.S. EPR value, the COL applicant will demonstrate that the radiological consequences meet applicable dose limits

Chapter 2, Site Characteristics: Supplemental Information

2.4 Hydrologic engineering

The U.S. EPR standard design considers groundwater, winter precipitation (snow, sleet, ice), rainfall, and surface flooding. The COL applicant is required to reconcile the site specific parameters with the standard design.

2.4.1 Hydrologic description – COL Applicant

- Site specific hydrologic characteristics

2.4.2 Floods – COL Applicant

- Site specific information on flood history, flood design, and effects of local precipitation

2.4.3 Probable maximum flood (PMF) on streams and rivers – COL Applicant

- Site specific information on the PMF of streams and rivers

2.4.4 Potential dam failures – COL Applicant

- Site specific information on failure of upstream or downstream water control structures

Chapter 2, Site Characteristics: Supplemental Information

2.4 Hydrologic engineering (Cont'd)

2.4.5 Probable maximum surge and seiche flooding – COL Applicant

- Site specific information on surge and seiche flooding and protection requirements

2.4.6 Probable maximum tsunami flooding – COL Applicant

- Site specific information on tsunami flooding and protection required

2.4.7 Ice effects – COL Applicant

- Site specific ice effects, induced ice forces and protection required

2.4.8 Cooling water canals and reservoirs – COL Applicant

- Site specific information is required on the design basis for cooling water canals and reservoirs used for makeup to the UHS cooling water structures

2.4.9 Channel diversions – COL Applicant

- Site specific channel information and demonstrate alternate water supplies will be available

Chapter 2, Site Characteristics: Supplemental Information

2.4 Hydrologic engineering (Cont'd)

2.4.10 Flooding protection requirements – COL Applicant

- Static and dynamic effects of flood conditions and protection of safety related equipment

2.4.11 Low water considerations – COL Applicant

- Identify natural events that may reduce or limit cooling water supply

2.4.12 Groundwater – COL Applicant

- Identify local and regional groundwater reservoirs, subsurface pathways, onsite use, monitoring measures, effect on structures

2.4.13 Pathways of liquid effluents in ground and surface waters – COL Applicant

- Ability of surface and groundwater to delay, disperse, dilute, or concentrate radioactive effluent releases and effects on future use of water resources

2.4.14 Technical specification and emergency operation requirements– COL Applicant

- Emergency measures to implement flood protection and verify adequate water supply for shutdown

Chapter 2, Site Characteristics: Supplemental Information

2.5 Geology, seismology, and geotechnical engineering

"Geology, seismology, and geotechnical engineering information are specific to the site and region and will be addressed by applicants on a site-specific basis."

" A range of generic site conditions has been selected for evaluating US EPR"

2.5.1 Basic geologic and seismic information – COL Applicant

- Data concerning geological, seismic, geophysical, and geotechnical information

2.5.2 Vibratory ground motion – COL Applicant

- Define the site specific SSE and compare to the Certified Seismic Design Response Spectra (CSDRS)

2.5.3 Surface faulting – COL Applicant

- No surface faults are allowed under safety related structures

2.5.4 Stability of subsurface materials and foundations – COL Applicant

- Site specific information about stability of subsurface materials under static and dynamic conditions

2.5.5 Stability of slopes – COL Applicant

- Evaluate the stability of earth and rock slopes both natural and manmade

Backup Slides

Table 2.1-1 - includes RAI Responses submitted since Revision 1

Table 2.1-1—U.S. EPR Site Design Envelope
Sheet 1 of 7

U.S. EPR Site Design Envelope	
Precipitation (Refer to Section 2.4)	
Rainfall rate	≤19.4 in/hr
Normal ground precipitation load	≤100 psf (100-year MRI)
Normal roof precipitation load	≤70 psf (100-year MRI)
48-hour PMWP liquid roof load	0 psf(1)
48-hour PMWP frozen ground load	≤43 psf (based on 55 inches)
48-hour PMWP frozen roof load	≤30 psf
Extreme winter precipitation roof load	≤100 psf (100-year MRI)
Seismology (Refer to Sections 2.5 & 3.7)	
Horizontal SSE Acceleration	0.3g Peak (CSDRS shapes – See Section 3.7)
Vertical SSE Acceleration	0.3g Peak (CSDRS shapes – See Section 3.7)
Fault Displacement Potential	No fault displacement is considered for safety-related SSC in U.S. EPR design certification.

Section 2.1

2.0 Site Characteristics

The U.S. EPR standard design is based on a set of conservatively established site characteristics. These characteristics represent more demanding site conditions than normally expected for most U.S. nuclear power plant sites. These site-related design basis parameters are provided in Table 2.1-1—U.S. EPR Site Design Envelope.

A COL applicant that references the U.S. EPR design certification will compare site-specific data to the design parameter data in Table 2.1-1. If the specific data for the site falls within the assumed design parameter data and characteristics in Table 2.1-1, then the U.S. EPR standard design is bounding for the site. For site-specific design parameter data or characteristics that are outside the bounds of the assumptions presented in Table 2.1-1, the COL applicant will confirm that the U.S. EPR design acceptably meets any additional requirements that may be imposed by the more limiting site-specific design parameter data or characteristic, and that the design maintains conformance to the design commitments and acceptance criteria described in this FSAR.

2.1 Geography and Demography

A COL applicant that references the U.S. EPR design certification will provide site-specific information related to site location and description, exclusion area authority and control, and population distribution.

2.1.1 Site Location and Description

The site location and description is site-specific and will be addressed by the COL applicant, including:

- Specific location by longitude and latitude, Universal Transverse Mercator (UTM) coordinates, and political subdivisions; the site's relative location with respect to natural and man-made features of the area such as highways, railways, and waterways; and local population distribution.
- A map of the site area of suitable scale (with explanatory text as necessary) showing relevant features such as the plant property lines, site and exclusion area boundaries (EAB), location and orientation of principal plant structures within the site area, and highways, railways and waterways that traverse or are adjacent to the site.

2.1.2 Exclusion Area Authority and Control

The authority for control of activities in the site exclusion area is site-specific and will be addressed by the COL applicant. This information will describe activities unrelated to plant operation that are permitted within the exclusion area.

Including RAI Responses submitted since Revision 1

Section 2.2

2.2 Nearby Industrial, Transportation, and Military Facilities

The U.S. EPR is designed to withstand the effects of external events resulting from such occurrences as earthquakes, storms, or other natural phenomena. This provides a robust design that can withstand a range of potential external hazards. A COL applicant that references the U.S. EPR design certification will provide site-specific information related to the identification of potential hazards stemming from nearby industrial, transportation, and military facilities within the site vicinity, including an evaluation of potential accidents (such as explosions, toxic chemicals, and fires).

2.2.1 Location and Routes

The location and routes for nearby industrial, transportation, and military facilities is site-specific and will be addressed by the COL applicant.

2.2.2 Descriptions

Nearby industrial, transportation, and military facilities are site-specific information and will be addressed by the COL applicant. This information will describe the primary function of each facility and the nature of the hazard it presents.

2.2.3 Evaluation of Potential Accidents

The U.S. EPR design is acceptable for any site when reasonable qualitative arguments can demonstrate that the realistic probability of severe consequences from any external accident is less than 10^{-6} occurrences per year. A COL applicant that references the U.S. EPR design certification will provide information concerning site-specific evaluations to determine the consequences that potential accidents at nearby industrial, transportation, and military facilities could have on the site. The information provided by the COL applicant will include specific changes made to the U.S. EPR design to qualify the design of the site against potential external accidents with an unacceptable probability of severe consequences (Reference 1).

2.2.4 References

1. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, March 2007.

Next File

Section 2.3

U.S. EPR FINAL SAFETY ANALYSIS REPORT

2.3 Meteorology

The U.S. EPR design is based on meteorological parameters (e.g., air temperature extremes, humidity, precipitation such as rainfall, snow and ice, maximum wind speeds, tornado wind speeds, and atmospheric stability characteristics) provided in Section 2.1, Table 2.1-1—U.S. EPR Site Design Envelope. If a COL applicant that references the U.S. EPR design certification identifies site-specific meteorology values outside the range of the design parameters in Table 2.1-1, then the COL applicant will demonstrate the acceptability of the site-specific values in the appropriate sections of the Combined License application.

2.3.1 Regional Climatology

The following information is provided in Section 2.1, Table 2.1-1:

- Weight of the normal winter precipitation event and the weight of the extreme winter precipitation event.
- 100-year, 3-second gust wind speed.
- Tornado parameters.
- Dry bulb and wet bulb temperatures.

2.3.1.1 Basis for Meteorological Parameters

The design parameters for the dry-bulb and wet-bulb temperatures are based on the EPRI ALWR Utility Requirements Document (Reference 1) and available Early Site Permit applications. The two percent annual exceedance dry and wet bulb temperature values, as recommended by RG 1.206 and SRP 2.3.1, are not provided in Table 2.1-1. However, the two percent annual exceedance dry and wet bulb temperature values are bounded by the provided zero percent annual exceedance and one percent annual exceedance dry and wet bulb temperature values.

SRP 2.3.1 and RG 1.206 also recommend that the 100-year maximum dry bulb and coincident wet bulb temperature values, the 100-year maximum non-coincident wet bulb temperature value, and the 100-year minimum dry bulb temperature values be provided. Instead, the zero percent exceedance values for these parameters have been provided. Zero percent exceedance values are based on conservative estimates of historical high and low values for potential sites.

The prescribed loads included in the combination of normal live loads are based on the weight of the normal winter precipitation event recorded at ground level. Winter precipitation loads to be included in the combination of extreme live loads is based on the addition of the weight of the extreme frozen or liquid precipitation event,

Tier 2 Revision 1 Page 2.3-1

Section 2.4

2.4 Hydrologic Engineering

The U.S. EPR is designed for a groundwater elevation up to 3.3 feet below the finished grade elevation and an exterior flood level of one foot below the finished grade elevation. For factored load combinations, the lateral soil load is based on saturated soil associated with flooding and groundwater. The finished yard grade is nominally one foot below ground floor top of concrete, with slopes provided for drainage to preclude water from entering the buildings. No safety-related dewatering systems are provided in the U.S. EPR. Flood protection features are described in Section 3.4.

The U.S. EPR is designed for a maximum rainfall rate of 19.4 inches per hour. A rain, snow, and ice load of 100 pounds per square foot has been used, which includes the weight of the normal winter precipitation event and the weight of the extreme winter precipitation event.

The hydrologic information in Section 2.4 is site specific and will be provided by the Combined License (COL) applicant that references the U.S. EPR design certification.

Sites are acceptable that are within the envelope of the groundwater and flood water maximum elevations described for the U.S. EPR standard plant design.

2.4.1 Hydrologic Description

A COL applicant that references the U.S. EPR design certification will provide a site-specific description of the hydrologic characteristics of the plant site.

2.4.2 Floods

A COL applicant that references the U.S. EPR design certification will identify site-specific information related to flood history, flood design considerations, and effects of local intense precipitation.

2.4.3 Probable Maximum Flood (PMF) on Streams and Rivers

A COL applicant that references the U.S. EPR design certification will provide site-specific information to describe the probable maximum flood of streams and rivers and the effect of flooding on the design.

2.4.4 Potential Dam Failures

A COL applicant that references the U.S. EPR design certification will verify that the site-specific potential hazards to safety-related facilities due to the failure of upstream and downstream water control structures are within the hydro-geologic design basis.

Section 2.5

2.5 Geology, Seismology, and Geotechnical Engineering

Geology, seismology, and geotechnical engineering information are specific to the site and region and will be addressed by applicants on a site-specific basis. A range of generic site conditions which encompasses a number of potential reactor sites throughout the United States has been selected for evaluating the U.S. EPR.

2.5.1 Basic Geologic and Seismic Information

A combined license (COL) applicant that references the U.S. EPR design certification will use site-specific information to investigate and provide data concerning geological, seismic, geophysical, and geotechnical information.

2.5.1.1 Regional Geology

Regional geology is site specific and will be addressed by the COL applicant.

2.5.1.2 Site Geology

Site-specific geology information will be addressed by the COL applicant.

2.5.2 Vibratory Ground Motion

A COL applicant that references the U.S. EPR design certification will review and investigate site-specific details of seismic, geophysical, geological, and geotechnical information to determine the safe shutdown earthquake (SSE) ground motion for the site and compare site-specific ground motion to the Certified Seismic Design Response Spectra (CSDRS) for the U.S. EPR.

The seismic design basis for the U.S. EPR is presented in Section 3.7.1.1.1. As noted therein, the U.S. EPR is designed for 0.3g peak ground acceleration (PGA) design ground motion which is defined as a hypothetical free-field outcrop motion at approximately 41.33 ft below grade at the bottom elevation of the foundation basemat for the Nuclear Island (NI) Common Basemat Structures (GDC 2). The certified seismic design response spectra (CSDRS) for the U.S. EPR are shown in Figure 3.7.1-1. The CSDRS are the same in both horizontal directions and in the vertical direction.

Section 3.7.1.3 describes a range of 10 generic soil profiles and associated dynamic soil properties selected for the design of the U.S. EPR. Table 3.7.1-6 shows the soil layering, the assumed strain-dependent properties, and the CSDRS design control motion associated with the profile. The variation in shear wave velocity in each of the assumed profiles is illustrated in Figure 3.7.1-31 and Figure 3.7.1-32. The soil properties associated with the various shear wave velocities assumed in the 10 generic soil profiles are discussed further in Section 3.7.2.4.1 and summarized in Table 3.7.2-9. Section 3.7.1.3 and Section 3.7.2.4.1 discuss that, for soil-structure interaction (SSI) analysis for the U.S. EPR design certification, the assumed generic shear wave

Including RAI Responses submitted since Revision 1

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Presentation to the ACRS Subcommittee

AREVA U.S. EPR Design Certification Application Review

Safety Evaluation Report with Open Items

Chapter 2: SITE CHARACTERISTICS

November 3, 2009

Staff Review Team

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  - **Kenneth See**
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  - **Weijun Wang**
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- **Project Managers**
  - **Getachew Tesfaye**
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Overview of Design Certification Application

SRP Section/Application Section		Number of RAI Questions	Number of SE Open Items
2.0	Site Characteristics	2	2
2.1	Geography and Demography	0	0
2.2	Nearby Industrial, Transportation, and Military Facilities	0	0
2.3	Meteorology	31	10
2.4	Hydrologic Engineering	4	0
2.5	Geology, Seismology, and Geotechnical Engineering	8	1
2.6	COL Information Items	0	0
Totals		45	13

Description of SE Open Items

- **RAI 274, Question 02-1:** Use the terms "site characteristics" and "site parameters" in COL Information Item 2.0-1 and FSAR Tier 2, Section 2.0, in accordance with the definitions provided in 10 CFR 52.1(a).
- **RAI 288, Question 02-2:** Use the terms "site characteristics" and "site parameters" in COL Information Item 2.0-1 and FSAR Tier 2, Section 2.0, in accordance with the definitions provided in 10 CFR 52.1(a).
- **RAI 256, Question 02.03.01-13***: Clarify whether 1% exceedance air temperature site parameter values are annual or seasonal exceedance values
- **RAI 256, Question 02.03.01-14***: Delete noncoincident wet bulb temperature as a site parameter and add a COL Information Item requiring COL applicants to validate the standard plant UHS cooling tower design using site-specific temperature profiles
- **RAI 256, Question 02.03.01-15:** Use titles for the winter precipitation site parameters that are consistent with terminology provided in ISG-7
- **RAI 288, Question 02.03.01-16**: Revise COL Information Item 2.3-1 to distinguish between site parameters and site characteristics as defined in 10 CFR 52.1(a) and describe how the actual site characteristics will be compared to the postulated design parameters set forth in the U.S. EPR FSAR.

Description of SE Open Items

- **RAI 256, Question 02.03.04-7***: Clarify the source/receptor information required to model control room *air intake* atmospheric dispersion factors
- **RAI 256, Question 02.03.04-8***: Provide the source/receptor information required to model control room *unfiltered inleakage* atmospheric dispersion factors
- **RAI 288, Question 02.03.04-9**: Remove distances from the titles of the EAB and LPZ atmospheric dispersion site parameters
- **RAI 256, Question 02.03.05-6***: Add the routine release atmospheric deposition (D/Q) value as a site parameter
- **RAI 256, Question 02.03.05-7*:** Clarify the routine release pathway characteristics
- **RAI 288, Question 02.03.05-8**: Remove distance from the title of the routine release atmospheric dispersion factor (χ/Q) site parameter
- **RAI 261, Question 02.05.04-4***: Did not provide details on how the minimum required dynamic bearing capacity was determined
  - Minimum value of 34,560 lb/ft^2 was provided without details on supporting analysis

*** Questions will be discussed in Technical Topics of Interest**

Technical Topics of Interest

Section 2.1 - Geography and Demography
Section 2.2 - Nearby Industrial, Transportation, and Military Facilities

Section 2.1 - Geography and Demography

- Site Location and Description
- Exclusion Area Authority and Control
- Population Distribution

Section 2.2 - Nearby Industrial, Transportation, and Military Facilities

- Identification of Potential Hazards in Site Vicinity
- Evaluation of Potential Accidents

The COL applicant is to provide this information as part of the COL application.

Technical Topics of Interest

Section 2.3 - Meteorology

SER 2.3: Meteorology

- Involves site specific information such as:
  - 2.3.1 – Regional Climatology
  - 2.3.2 – Local Meteorology
  - 2.3.3 – Onsite Meteorological Measurements Program
  - 2.3.4 – Short-term Atmospheric Dispersion Estimates for Design-Basis Accidental Releases
  - 2.3.5 – Long-term Atmospheric Dispersion Estimates for Routine Releases
- The COL applicant is to provide this information as part of the COL application

Meteorological Site Parameters

- The applicant identified meteorological site parameters related to:
  - Climate Extremes and Severe Weather
  - Atmospheric Dispersion (Accident & Routine Releases)
- A COL applicant needs to demonstrate that its site characteristics fall within the U.S. EPR site parameters
- The staff evaluated the U.S. EPR meteorological site parameter values to ensure they are representative of a reasonable number of sites that have been or may be considered for a COL application

Technical Topics of Interest
Section 2.3 - Meteorology

Climatic Site Parameters

- Winter Precipitation (for Roof Load Design)
- Maximum Wind Speed (other than Tornado)
- Tornado
- Air Temperature
  - RAI 256, Question 02.03.01-13: Clarify whether 1% exceedance values are annual or seasonal exceedances
  - RAI 256, Question 02.03.01-14: Delete noncoincident wet bulb temperature as a site parameter
- UHS Meteorological Conditions
  - RAI 256, Question 02.03.01-14: Add a COL Information Item requiring COL applicants to validate the standard plant UHS cooling tower design using site-specific temperature profiles

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Short-Term Dispersion Site Parameters for Design-Basis Accident Releases

- EAB and LPZ χ/Q Site Parameter Values
- CR χ/Q Site Parameter Values
  - RAI 256, Question 02.03.04-7: Clarify the source/receptor information required to model CR *air intake* atmospheric dispersion factors
  - RAI 256, Question 02.03.04-8: Provide the source/receptor information required to model CR *unfiltered inleakage* atmospheric dispersion factors
  - Confirmatory Action NRC (RAI 10, Question 02.03.04-2): Evaluate the reasonableness of the applicant's CR χ/Q site parameter values

Long-Term Dispersion Site Parameters for Routine Releases

- Site Boundary χ/Q Values
  - RAI 256, Question 02.03.05-6: Add the routine release atmospheric deposition (D/Q) value as a site parameter
  - RAI 256, Question 02.03.05-7: Clarify the routine release pathway characteristics

Technical Topics of Interest
Section 2.3 - Meteorology

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COL Information Items

- The COL applicant is to provide information on climate and atmospheric dispersion site characteristics
- If a COL applicant identifies site-specific meteorological values outside the range of the U.S. EPR site parameter values, then the COL applicant will demonstrate the acceptability of the design

CONCLUSION

Section 2.3 - Meteorology

- Except for the SE Open Items:
  - Applicant has identified an appropriate list of site parameters
  - The values assigned to each of the site parameters are expected to be representative of a reasonable number of sites that may be considered for a COL application

Technical Topics of Interest
Section 2.4 -Hydrologic Engineering

Involves site specific information such as

- 2.4.1 Hydrological description
- 2.4.2 Floods
- 2.4.3 Probable Maximum Flood on Streams and Rivers
- 2.4.4 Potential Dam Failures
- 2.4.5 Probable Maximum Surge and Seiche Flooding
- 2.4.6 Probable Maximum Tsunami Flooding
- 2.4.7 Ice Effects
- 2.4.8 Cooling Water Channels and Reservoirs
- 2.4.9 Channel diversion
- 2.4.10 Flood Protection Requirements
- 2.4.11 Low Water Considerations
- 2.4.12 Groundwater
- 2.4.13 Accidental Release of Liquid Effluents in Ground and Surface Water
- 2.4.14 Technical Specifications and Emergency Operations Requirements

Information in all sections to be provided as part of the COL application.

Technical Topics of Interest

Section 2.4 -Hydrologic Engineering

- Hydrologic Parameters
  - The applicant identified three hydrologic parameters
    - Maximum groundwater level (3.3 ft below finished grade)
    - Maximum flood level (1 ft below finished grade)
    - Maximum rainfall rate (19.4 in/hr.)
- A COL applicant needs to demonstrate that its site characteristics fall within the U.S. EPR FSAR site parameters
- The staff evaluated these three parameters for reasonableness.

Conclusion

Section 2.4 – Hydrologic Engineering

- Applicant has properly identified information to be provided as part of the COL application.

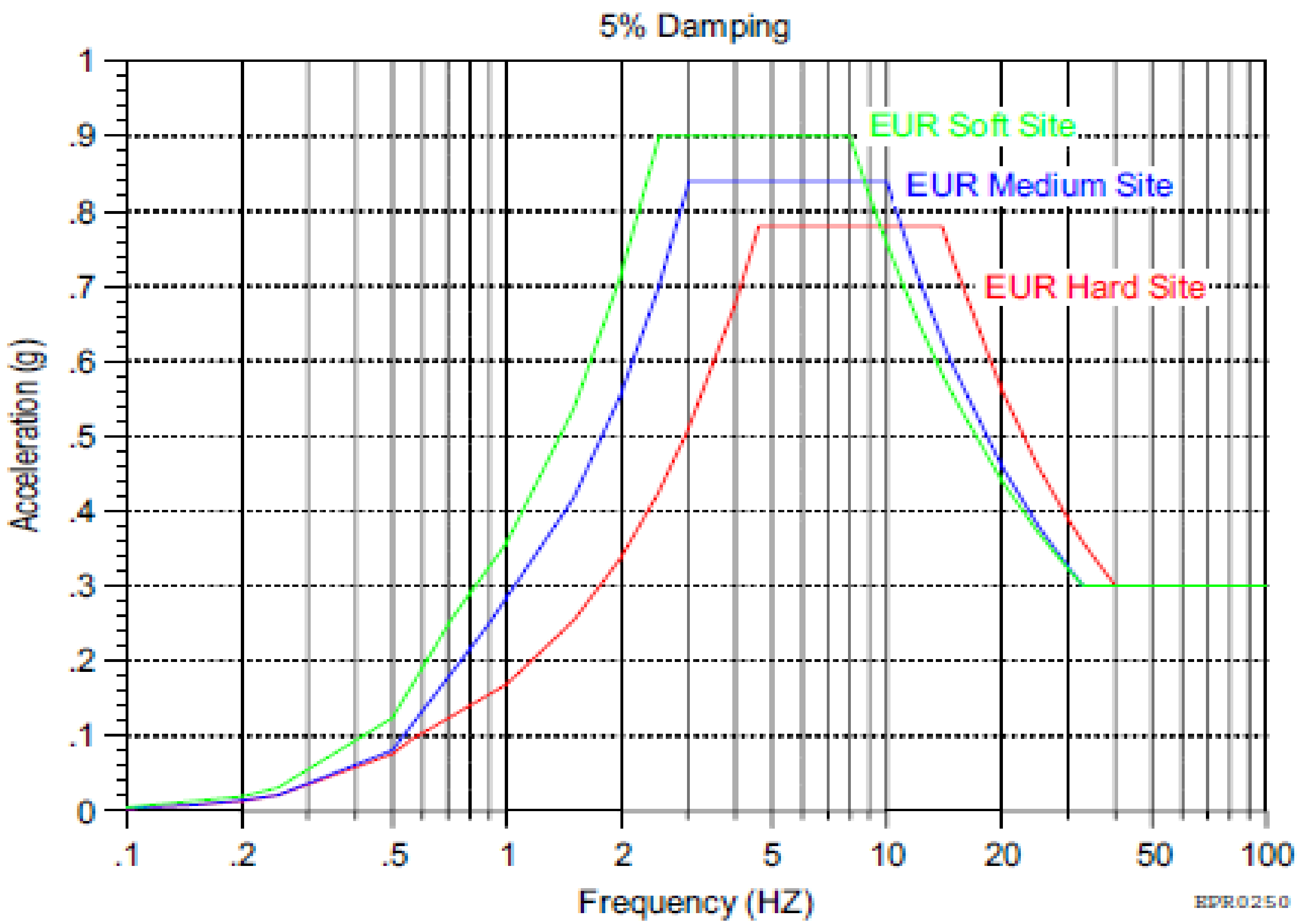
Technical Topics of Interest
Section 2.5 – Geology, Seismology, and Geotechnical Engineering

- Establishes subsurface acceptance criteria for a site
  - Minimum bearing capacity
  - Minimum shear wave velocity
  - Subsurface uniformity
  - Maximum settlement, etc.

  RAI 261, Question 02.05.04-4: Did not provide details on determination of dynamic bearing capacity

- Establishes three certified seismic design response spectra (CSDRS) to be met for a site
  - Based on 10 generic soil profiles
  - Divided into 3 site groups: soft, medium and hard
  - Anchored at 0.3g peak ground acceleration

FSAR Tier 1, Figure 5.0-1 – <u>Design Response Spectra for EUR Control Motions (Hard, Medium and Soft Sites)</u>



CONCLUSION
Section 2.5 – Geology, Seismology, and Geotechnical Engineering

- Except for the SE Open Items:
  - Postulated parameters used in design are reasonable
  - Requirements for COL applicant to establish site-specific characteristics in determining whether they meet the standard design parameters followed NRC regulatory guidelines

ACRONYMS

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- SE – safety evaluation
- RAI – request for additional information
- COL – combined license
- D/Q - deposition factor ($1/m^2$)
- EAB - exclusion area boundary
- LPZ - outer boundary of the low population zone
- UHS - ultimate heat sink
- χ/Q - atmospheric dispersion factor (sec/m^3)

THE END