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

January 17, 2017

MEMORANDUM TO: ACRS Members

FROM: Maitri Banerjee, Senior Staff Engineer **/RA/**
Technical Support Branch
Advisory Committee on Reactor Safeguards

SUBJECT: CERTIFICATION OF THE MINUTES OF THE ACRS APR 1400 SUBCOMMITTEE ON NOVEMBER 29, 2016, ROCKVILLE, MARYLAND

The minutes for the subject meeting were certified on January 12, 2017. Along with the transcripts and presentation materials, this is the official record of the proceedings of that meeting. A copy of the certified minutes is attached.

Attachment: As stated

cc with Attachment: A. Veil
M. Banks

UNITED STATES
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WASHINGTON, DC 20555 - 0001

MEMORANDUM TO: Maitri Banerjee, Senior Staff Engineer
Technical Support Branch
Advisory Committee on Reactor Safeguards

FROM: Matthew Sunseri, Co-Chairman
APR1400 Subcommittee
Advisory Committee on Reactor Safeguards

SUBJECT: CERTIFIED MINUTES OF THE ACRS APR1400 SUBCOMMITTEE MEETING ON NOVEMBER 29, 2016

I hereby certify, to the best of my knowledge and belief, that the minutes of the subject meeting on November 29, 2016, are an accurate record of the proceedings for that meeting.

/RA/ **January 12, 2017**

Matthew Sunseri, Co-Chairman Dated
APR1400 Subcommittee

Certified on: January 12, 2017
Certified by: M. Sunseri

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
MINUTES OF THE APR1400 SUBCOMMITTEE MEETING ON
NOVEMBER 29, 2016, ROCKVILLE, MD

The ACRS APR1400 Subcommittee held a meeting on November 29, 2016 in T2B1, 11545 Rockville Pike, Rockville, Maryland. The meeting convened at 8:30 a.m. and adjourned at 5:12 p.m. The meeting was open to the public.

No written comments or requests for time to make oral statements were received from members of the public related to this meeting.

ATTENDEES

ACRS Members/Staff:

R. Ballinger, Chairman
C. Brown, Member
J. Rempe, Member
D. Skillman, Member
D Bley, Member
Matthew Sunseri, Co-Chairman
C. Brown, ACRS Staff (DFO)
Maitri Banerjee, ACRS Staff*

J. Stetkar, Member
H. Ray, Member
Jose A. March-Leuba, Member
D. Powers, Member
W. Kirchner, Member

KHNP, NRC Staff, Consultants & Other Attendees:

J. CIOCCO, NRO	ROBERT FITZPATRICK, NRR
SWAGATA SOM, NRR	SHEILA RAY, NRR
MARY JANE ROSS-LEE, NRR	NGOLA OTTO, NRR
FANTA SACKO, NRR	MICHAEL MCCOPPIN, NRO
TANIA MARTINEZ NAVEDO, NRR	ROY MATHEW, NRR
ADAKOU FOLI, NRR	DUC NGUYEN, NRR
JORGE A. CINTRON, NRR	NADIM KHAN, NRR
ANDREA MAYER, NRO	ANGELO STUBBS, NRO
GEORGE WUNDER, NRO	CHEWUNG HA, KHNP
SUN YOEB CHOI, KEPCO AE	HYEOK JEONG, KEPCO-E&C
DAEGUN (TONY) AHN, KHNP	KYUNGWOONG KANG, KEPCO-E&C
JUNGHO KIM, KHNP	SEUNGDAE KIM, KEPCO-E&C
SEOKHWAN HUR, KEPCO E&C	TAE HAN KIM, KEPCO E&C
	STEVEN MANNON, AECOM

*participating via telephone

SUMMARY

The purpose of the meeting was for the ACRS members to receive a briefing on the Korea Hydro and Nuclear Power Company (KHNP) design certification application (DCA) and NRC staff review specific to Tier 2 Chapter 8 and related information. The meeting transcripts are attached and contain a description of each matter discussed during the meeting. The presentation slides and handouts used during the meeting are attached to these transcripts.

The following list describes significant issues discussed during the meeting with the corresponding pages in the transcript referenced. Unless specifically noted the chapter and section references belong to the DCD Tier 2 submittal or staff safety evaluation report (SER).

SIGNIFICANT ISSUES	
Issue	Reference Pages in Transcript
Chairman Ballinger convened the meeting by introducing the ACRS members present. He noted the purpose of the meeting was to review KHNP DCA and staff review related to APR1400 Chapter 8.	4-6
After short introductions by Mr. Mike McCoppin, Branch Chief, Licensing Branch 2, NRO, and Mary Jane Ross-Lee, deputy director for the division of electrical engineering, NRR, Mr. Robert Sisk, Westinghouse, representing KHNP APR1400 DCA, introduced the presenters.	7-8
Mr. Kyungwoong Kang, KEPCO-E&C, technical lead of the APR1400 electric power system, started the presentation by providing an outline of the distribution system, which is for a single unit. Upon member's question he discussed the connection between the PPS and AAC. He discussed how the design meets GDC 17. Member Stetkar noted the normal and alternate preferred sources are routed through the same fire zone after they exit the Non-Class 1E switchgear room, and asked for clarification. A discussion followed.	8-20 Slides 1-10
Mr. Kang discussed open phase conditions and KHNP response to the NRC Bulletin. He noted KHNP performed a design vulnerability study that resulted in a dedicated open phase detection and protection (OPD) system on the primary side of power transformers, in addition to the conventional protective relays in the design. Upon staff questions (RAI) a COL information item was developed.	20-24 Slides 11-12
Mr. Kang discussed independence, redundancy, and testability of the onsite electric power supplies. He discussed various operating modes including LOOP and beyond design basis external event which involves extended loss of all AC power. Upon member Stetkar's question he	24-34 Slides 13-16

discussed interlocks between the incoming circuit breakers in the UAT and SAT. A long discussion followed regarding paralleling the buses for a manual transfer between UAT and SAT.	
Upon member Skillman's question, a discussion broke out regarding the reliability of solid state inverters over motorized ones.	37-41
Mr. Kang presented the battery capacities. Upon member Stetkar's question, he went into a discussion of load shedding to extend battery life.	41-46 Slides 17-21
Mr. Seungdae Kim, KEPCO-E&C, described the design and operation of the emergency diesel generators. Member Stetkar asked about load sequencing when only one bus, 4.16 kV Class 1E Bus 1A, loses power from both the UAT and SAT, and a discussion of various load sequencing actions occurred.	47-52 Slides 22-25
Member Stetkar wanted KHNP to confirm the essential chillers that they can be tripped and restarted within 47 seconds after diesel start. Mr. Kim did not have an answer, and it was taken for Chapter 9 presentation.	52-54 63-64
Mr. Kim discussed the alternate AC gas turbine generator (LOOP power supply) and SBO response. Member Stetkar asked for details regarding the bus transfer upon recovering from a station blackout. Also upon a LOOP, availability of diesel buses may require handling it like an SBO. Member Bley delved into possibility of back-feeding from a permanent non-safety (PNS) bus through the AAC GTG bus to a safety bus.	56-67 69-70 Slides 26-32
Mr. Kang presented a Chapter 8 SER open item summary. There are five open items in staff SER.	67-73 Slides 33-36
After a recess, Mr. George Wunder, NRO, started the staff presentation by introducing the reviewers of Chapter 8. Mr. Ngola Otto discussed Section 8.1, Introduction, and noted staff review was to determine whether the electrical system had adequate capacity, capability, redundancy, independence, and testability.	74-77 Slides 4
Member Stetkar asked why the unit auxiliary transformers and the main transformer are not considered to be risk significant equipment that are included in the scope of the reliability assurance program. Staff could not answer it.	77-78
Mr. Otto discussed staff review for Compliance with GDC 17. Members Stetkar asked: 1. Would NRC would accept a design of the UATs and SATs, with three secondary windings each, when one secondary winding was 13.8 kV non-safety, and one secondary winding was 4.16 kV non-safety, and one secondary winding was 4.16 kV safety. 2. Would NRC accept a plant design with a single UAT that supplied all four safety-related buses, and only safety-related buses, and a single	78-89 Slides 5-9

SAT that also supplied all four safety-related buses, and only safety-related buses. 3. If both of those designs would be acceptable, then provide a reliability analysis to demonstrate why those other designs provide more reliable power supply than the design being proposed by KHNP. A discussion regarding fault propagation through the common winding from the non-safety 4160 to the safety 4160 side followed, with member Stetkar noting that faults in the transformer itself are more likely than combination of a fault with a failure of detection in the load breaker and the high side breaker to the bus, hence call for a reliability analysis. Also, member Bley noted that the staff's SRP reference may need to be backed up by analysis.	
Ms. Sheila Ray presented the offsite power system. Member Bley noted disagreement with staff's claim that feeding from the same winding of a transformer, the non-1E and the 1E, was equivalent to having an intermediate non-1E bus. APR1400 design has the COL applicant to design the offsite power system to detect, alarm, and mitigate against open phase conditions (open item in staff SER). Staff was not ready to discuss details as they were reviewing a KHNP response dated November 14th.	90-94 Slides 10-12
Ms. Swagata Som presented staff review of APR1400 onsite AC power system. Members raised a question of how to address shared systems in case of an applicant selecting a double unit plant while the DC referred to a single unit. Member Stetkar asked if the staff looked at the power supplies for the motor-operated valves associated with the POSRVs and the discharge lines and confirm that they are consistent with 10 CFR 50.34 and the TMI recommendations. This was taken as a future follow-up item by staff.	94-103 Slides 13-14
Ms. Som presented the findings of the staff audit related to various calculations and methodologies on the electric power distribution system. Member Skillman asked the staff to identify changes that must be made for the result of ETAP to be acceptable under GDC 17 (audit finding). A response followed.	100-102
Ms. Som presented staff review of APR1400 onsite DC power system. There are no open items in staff SER.	103-104 Slides 15-16
Ms. Adakou Foli presented SER Section 8.4 on station blackout. The staff determined that no coping analysis was required to demonstrate the design station blackout capability since, in accordance with the guidance provided in Regulatory Guide 1.155, the AAC GTG power source meets the recommended criteria for an emergency power source. There are no open items for SER Section 8.4.	105-115 Slides 17-18
Regarding APR1400 design capability of 16 hour coping duration member Powers asked if the design would preclude extending this to longer times.	107-115

Staff took the question for future follow up. A discussion followed and Chapter 19 was mentioned regarding the beyond design basis external events with no AC power from any source available.	
Member Bley wanted to know if there was a subsequent SRM issued to SECY 91-078 finalizing Commission position first issued on April 1, 1991, and asked ACRS staff for a copy.	115-116
Member Skillman wanted to know the safety classification for the cathodic protection system. Staff took this question for future follow up.	117-118
Mr. Sisk started KHNP presentation to provide responses to members' questions that had been raised at previous meetings. Mr. Seokhwan Hur, KEPCO-E&C started presentation of responses for Chapter 2 and 10 questions. He noted Chapter 5 questions would be addressed by Tae Han Kim, and Chapter 11 questions would be addressed by Hyeok Jeong. Members Stetkar and Bley noted that to allow review time a copy of written response (does not need to be formal) in lieu of formal presentation would be another way of addressing individual member's questions. Member Rempe noted that member's question on design limits of the wet bulb temperature was not addressed.	119-145 Slides 1-21
Mr. Hur presented responses to members' questions on Chapter 10. Regarding question on controllable capacity of MSADV (re: 10/4/2016 Transcript P68-Stetkar), member Stetkar noted that he wanted to know if the operator can control the full range of the valve.	145-153 Slide 22-31
Mr. Hyeok Jeong, KEPCO-E&C, presented responses to members' questions on Chapter 11.	153-157 Slides 32-35
Chairman Ballinger asked for comments from the public. None were provided.	157
Chairman Ballinger asked for comments from the members. Member Rempe noted she was looking for a plan to move forward, especially regarding interim letters. A discussion followed, and February ACRS meeting was noted. NRO PM Jeff Ciocco noted that during the December 14 Subcommittee meeting staff plans to address some members' questions on Chapter 5. Staff may have to write RAIs to address some of the questions or decide to address at Phase 5 (SER with no open items). Member Bley noted that scope of the ACRS Full Committee meetings needed to be decided and that some of the Chapter 8 questions could be candidates in an ACRS letter.	158-162
Chairman Ballinger adjourned the meeting at 5:12 p.m.	163

Following follow-up issues resulted from questions and issues the members raised for which a response was not available at the meeting:

KEY FOLLOW-UP ISSUES	
Key Issues	Reference Pages in Transcript
KHNP to confirm that the essential chillers can be tripped and restarted within 47 seconds after diesel start.	52-54
KHNP to address why the unit auxiliary transformers and the main transformer are not considered to be risk significant equipment that are to be included in the scope of the reliability assurance program.	77-78
Question on staff open item regarding UAT and SAT winding design - NRC acceptability of UAT and SAT designs: one with three secondary windings where two supplied non-safety and one supplied safety buses; vs. design where a single UAT and SAT supplied all four safety-related buses only. Also, reliability analysis to demonstrate why the other designs provide more reliable power supply than the design being proposed by KHNP.	82-84
Staff to address if the power supplies for the motor-operated valves associated with the POSRVs and the discharge lines meet 10 CFR 50.34 and TMI recommendations?	97
Staff to address if the KHNP design precludes extending the 16 hour coping duration to longer times.	107-109
Staff will check if there was a subsequent SRM issued to SECY 91-078 finalizing Commission position first issued on April 1, 1991.	115-116
Staff to follow up on safety classification for the cathodic protection system.	117-118

Documents provided to the Subcommittee (CDs provided by KHNP)

1. APR1400 Design Description
2. APR1400 Design Control Document (Tier 1 and 2-Proprietary & Security Related Information)
3. APR1400 Technical Reports (Proprietary)
4. System 80 Design DCD and SER
5. Staff SER with open items on Chapter 8

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards
APR1400 Subcommittee

Docket Number: N/A

Location: Rockville, Maryland

Date: November 29, 2016

Work Order No.: NRC-2766 Pages 1-157

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

+ + + + +

APR1400 SUBCOMMITTEE

+ + + + +

TUESDAY,

NOVEMBER 29, 2016

+ + + + +

ROCKVILLE, MARYLAND

+ + + + +

The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 1:01 p.m., Ronald G. Ballinger, Chairman, presiding.

COMMITTEE MEMBERS:

RONALD G. BALLINGER, Chairman

MATTHEW W. SUNSERI, Co-Chair

DENNIS C. BLEY, Member

CHARLES H. BROWN, JR. Member

WALTER L. KIRCHNER, Member

JOSE MARCH-LEUBA, Member

DANA A. POWERS, Member

HAROLD B. RAY , Member

JOY REMPE, Member

GORDON R. SKILLMAN, Member

JOHN W. STETKAR, Member

DESIGNATED FEDERAL OFFICIAL:

CHRISTOPHER L. BROWN

ALSO PRESENT:

TONY AHN, KHNP

SUN YOEB CHOI, KEPCO AE

JORGE A. CINTRON, NRR

JEFF CIOCCO, NRO

ROBERT FITZPATRICK, NRR

ADAKOU FOLI, NRR

CHEWUNG HA, KHNP

SEOKHWAN HUR, KEPCO-ENC

HYEOK JEONG, KEPCO-ENC

KYUNGWOONG KANG, KEPCO-ENC

NADIM KHAN, NRR

JUNGHO KIM, KHNP

SEUNGDAE KIM, KEPCO-ENC

TAE HAN KIM, KEPCO-ENC

STEVEN MANNON, AECOM

TANIA MARTINEZ NAVEDO, NRR

ROY MATHEW, NRR

ANDREA MAYER, NRO

MICHAEL MCCOPPIN, NRO

DUC NGUYEN, NRR

JIYONG OH, KHNP

NGOLA OTTO, NRR

SHEILA RAY, NRR

MARY JANE ROSS-LEE, NRR

FANTA SACKO, NRR

SWAGATA SOM, NRR

ANGELO STUBBS, NRO

GEORGE WUNDER, NRO

* Present via telephone

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

1:01 p.m.

CHAIR BALLINGER: The meeting will now come to order. This is a meeting of the APR1400 subcommittee of the advisory committee on reactor safeguards. I'm Ron Ballinger, chairman of the APR1400 subcommittee, and to my left is Matt Sunseri, who's the co-chair. ACRS members in attendance today are Harold Ray, Gordon Skillman, Dana Powers, Matt Sunseri, Dennis Bley, John Stetkar, Jose March-Leuba, and Charles Brown, and our token female --

MEMBER BROWN: I didn't realize the spelling was so hard, and you got nailed, too. You're the token female, and I'm the token cartoon character here.

CHAIR BALLINGER: Got to be able to laugh at yourself. The purpose of today's meeting is for the subcommittee to receive briefings from Korea Hydro and Nuclear Power Company, KHNP, regarding their design certification application, and the NRC staff, regarding a review of safety evaluations specific to

Chapter 8, electric power. This meeting is fourth in a series of meetings of our subcommittee to review the KHNP application and related NRC staff safety evaluation. The rules for participation in today's meeting were announced in the Federal Register on November 18, 2016. The meeting was -- November 18th -- 11/16. The meeting was announced as open, but portions can be closed, as necessary, to protect information proprietary to KHNP or its vendors, pursuant to 5 USC 552(b)(c)(4). No request for making a statement to the subcommittee has been received from the public.

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 of this meeting use the microphones located throughout the meeting room when addressing the subcommittee. We seem to always forget, but there's a button on this little thing in front of you. It's not the little led that you have to push, it's down in the front.

Where was I? Participants should first identify themselves and speak with sufficient clarity and volume so they can be readily heard. We have one

bridge line established for interested members of the public to listen in. The bridge number and the password were published in the agenda posted on the NRC website. To minimize disturbance, this public line will be kept in a listen mode only, and I might add that if you're out there and you're listening, please mute your phone or whatever you're using to listen, unless you're talking, because it causes cross-talk, which gets everybody messed up. The public will have an opportunity to make a statement or provide comments at a designated time towards the end of this meeting.

We request that meeting attendees and participants silence their cell phones and other electronic devices. In addition, while we're going to see the slides for Chapter 8, KHNP has also provided a set of slides which are answers to individual members' questions from past chapters, so they're, again, individual members' questions.

If we have time at the end, we can deal with that, but that's not our priority. It's Chapter 8. Don't worry about trying to finish early so we can do those. They'll be on the record. I invite the branch chief, Mike Coppin, I think.

MR. MCCOPPIN: Good afternoon. I'm Mike McCoppin. I'm the new Licensing Branch 2 branch chief for the division of new reactor licensing, pleasure to be here. I have my lead project manager, Jeff Ciocco, behind me. I'd like to introduce Mary Jane Ross-Lee, deputy director for the division of electrical engineering.

MS. ROSS-LEE: Good afternoon. I am neither Jake nor Josh.

CHAIR BALLINGER: I was going to say, I'm looking at the name tags, and I'm not seeing anything --

MS. ROSS-LEE: -- neither of which are actually NRO. As Mike said, I'm the deputy director, division of engineering at NRR. We have the COE for electrical, so we do both the operating and new reactor electrical reviews. In the staff's presentation today, they will be talking about the safety evaluation with open items for Chapter 8, which covers the electrical power systems. During their review, staff has engaged with the applicant on the issues, and we will discuss two topics that remain as open items for Chapter 8. Thank you.

CHAIR BALLINGER: The floor is yours.

MR. SISK: Thank you, Dr. Ballinger. Good afternoon. I'm Robert Sisk, Westinghouse, representing KHNP APR1400 DCA. We look forward to the discussion today on Chapter 8 and electrical system. I do want to echo your comment. We do have a set of slides to -- our intent is to be responsive, where appropriate and practical, to subcommittee questions. As we go through these series of subcommittee meetings, I know that some of the answers asked build on or prepare for future, so we will be providing, routinely, as we go through, responses, where we can, with the meetings, to hopefully address the questions raised at the previous set of ACRS meetings. Again, that's as time available. The focus will be on Chapter 8. With that, I can turn it over to Mr. Kang for leading us through Chapter 8, or back to you, Dr. Ballinger.

MR. KANG: Good morning, ladies and gentlemen. I'm Kyungwoong Kang, also known as Alex -- you can call me simply Alex -- from KEPCO-ENC, currently serving as technical lead of the APR1400 electric power system. Sitting on my left, Seungdae Kim from KEPCO-ENC, who is responsible for electric machines and circuit design of the APR1400 electrical

power system.

Seated on my right, Steven Mannon, who is project manager of Chapter 8, who is supporting my presentation today. Both of us will share the part of presentation of APR1400 DCD Tier 2, Chapter 8, electric power system and delivery from now on. First, I will briefly introduce the contents of Chapter 8 and go over some of the section of Chapter 8. In the section summary, myself and Mr. Kim will share each responsible part, and then I'll speak about the open items continuing in Chapter 8 safety evaluation report and current status of Chapter 8 review, and then I'll conclude with a summary of Chapter 8. Chapter 8 of the APR1400 DCD Tier 2 consists of four sections.

Section 8.1 provides introduction to the APR1400 electric power system, and also describes design basis of the systems. Sections 8.2 and 8.3 provide descriptions on the design features of offsite power and onsite power system and design conformance of the systems with 10 C.F.R. 50 and regulatory guides. Section 8.4 deals with the APR1400 strategies to cope with a station blackout and its conformance with 10 C.F.R. 50 and regulatory guides.

This is a diagram taken from DCD Tier 2 Figure 8.1-1, showing overall electric power system of the APR1400, this is only of Division 1 part. Division 2 part is mostly identical to Division 1 part, and we have the same portion of Division 1 for safety functions. Firstly, electric power system is divided into offsite power system and onsite power system. The onsite power system is divided, also, again, into Class 1E system and Non-Class 1E system by electrical classification, and each Class 1E and Non-Class 1E onsite power system is further broken down to AC/DC and instrumentation control power system by type of electric power supply.

MEMBER REMPE: Out of curiosity, if you could go through this, is the way you've designed this and arranged this, is this similar to the plant being -- starting up in Korea and the plant that the United Arab Emirates -- has the design -- because they're multiple units ones, and this is a single unit design certification. Are there any changes that you've made, or is this the same throughout?

MR. KANG: Within the scope of design certification design, we have mostly identical APR1400 at this -- certified design is mostly identical to the

reference plant from Korea, singly, at three and four. We don't know the APR1400 plans will be a single unit or a double unit. It's up to the applicants.

MEMBER REMPE: Right, so that's why I was curious, but it is similar to what's going on Shin-Kori three and four.

MR. KANG: Yes, 99 percent.

MEMBER REMPE: Thank you.

MR. KANG: This is a simplified and color-coded single-line diagram showing the offsite power system and its interface with the onsite power system. The boundaries of APR1400 electric power system design is up to the high voltage side terminals of main transformer and standby aux transformer. Design of the upstream network of those points is within the scope of COL applicants. The role of offsite power system is to transmit generated power to the grid during normal operation and to provide grid power to the plant auxiliaries during normal, abnormal, startup and shutdown conditions, specifically, the offsite power supply being delivered from transmission system to the Class 1E buses is referred to as preferred power supply, by abbreviation, PPS.

The APR1400 provides two PPS, normal PPS and alternate PPS. Normal PPS, so called PPS I, is supplied to main transformer and unit aux transformer. The alternate PPS, so-called PPS II is supplied to the standby aux transformer from the grid. In this slide, normal PPS circuit is shown in solid line and alternate PPS circuit is shown in dot line and red color represents Division 1 connections. Blue color represents Division 2 connections.

GDC-17 is sort of governing requirement for the off-site power system and on-site power system as well. According to GDC-17, the offsite power system shall provide sufficient capacity and capability for all step functions and offsite power supply shall be provided by two physically independent circuits and each circuit shall be available in sufficient time when there is no other source available. At least one circuit shall be available within three seconds following a loss of coolant accident.

MEMBER SKILLMAN: Alex, please back up one slide, please.

MR. KANG: Okay.

MEMBER SKILLMAN: You've explained PPS I,

PPS II and Division 1 and Division 2 by color and by dotted line. In the middle, you have the alternate AC power with four blocks. Would you please explain that figure? What are you communicating with AAC and red 1 and blue 2, blue 3 and blue 4?

MR. KANG: In this picture you can see solid line and dot line from offsite power network to the onsite bus. So solid line stands for PPS I circuit and dot line stands for PPS II circuit. Each PPS circuit -- PPS I and PPS II -- PPS I circuit is providing power to Division 1. It can provide to Division 2 as well. Alternate PPS as well provides power to Division 1 and it can Division 3. So by -- between PPS I and PPS II circuit is discriminated by the type of line, and between Division 1 and Division 2 and corresponding offsite power circuit. It is discriminated by different colors.

MEMBER SKILLMAN: Okay. Now you have an AAC. Would explain that little image please?

MR. KANG: AAC has two functions. In the event of station blackout , it provides power for safe shutdown and it is aligned to either A or B safety bus, and it provides power for essential permanent non-safety load, essential load. It has connections,

as well, to two PNS buses No. 1 and No. 2 is connections to twin A and twin B bus. No. 3 and No. 4 connections are connection to PNS buses. That's why I colored in red and blue for No. 1 and No. 2 and colored in black for No. 3 and 4.

MEMBER SKILLMAN: Thank you.

MR. KANG: You're welcome.

CO-CHAIR SUNSERI: I have one question on that, as well. You show that the breaker for the connection to the 4.1 kV bus to be normally closed, and all the other ones are open. Why is that the case? MR. KANG: If you look at PPS I circuit breaker, it is shown in solid. PPS II breakers are shown in empty, blank, because PPS I is normal power supply. Normally, the breaker is in closed state, closed position. PPS II is alternate power supply. During normal operation, the breaker is in open position. If you look at connections from UAT to the bus, the breaker status are closed. Connections from SATs to the buses, the breaker status are open, empty.

If you look at the AAC bus, one breaker is closed because during normal operation, AAC facility has to receive power from the grid. At least one circuit breaker should be closed to receive power to

maintain the AAC facility.

CO-CHAIR SUNSERI: Okay, thank you.

MR. KANG: Each power circuit shall be available in sufficient time and there's no other source available, when circuits shall be available within a few seconds following a loss-of-coolant accident. The design of transmission network is not in the scope of APR1400 design. However, according to GDC-17, the transmission network should include at least two physically independent circuits and sufficient capacity and capability for the APR1400. The COL applicant is to identify and provide information on the transmission circuits. Also, the switchyard design is not bound to specific APR1400 design. It is also in scope of COL applicant.

Therefore, the COL applicant is to address the detailed design and required analyses for the switchyard's incremental system, including failure mode effects analysis. As read in the previous slide within the APR1400 design, remain the matter of the offsite power supply and system comprises main generator, generator circuit breaker, insulated phase bus, main transformer, two unit aux transformers, two standby aux transformers, each one dedicated to

Division 1 and Division 2 and associated protection and control facility.

The offsite power system components and circuits are inherently non-safety related, Non-Class 1E, and boundaries between offsite power system and onsite power system is entry of incoming circuit breakers of the medium voltage switchgear. Each Class 1E feeds A, B, C, and D to offsite circuit from UATs and SATs are connected directly with no intervening non-safety buses. This is related to GDC-17 requirement and SECY-91-078 requirements. It should have two UATs and two standby aux transformers, each sized to provide the required power for the worst case loading during normal, abnormal, and DBA conditions. Between the two PPS circuit -- PPS I circuit and PPS II circuit -- separation is maintained to a practical extent to minimize the likelihood of simultaneous failure of both PPS circuits. During normal generation, the main generator produces electric power and delivers generated power to the grid, and also supplies Class 1E and Non-Class 1E plant auxiliary loads to the unit aux transformers. In case the main generator is failed or not in service for maintenance, normal path

of offsite power supply is secured by opening the generator circuit breaker.

In this case, normal offsite power supply's still available without interruption. In the event of a fault at normal offsite power circuit, for instance, at main transformer, aux transformer, or isolated phase bus, offsite power supply to the plant auxiliary is switched to alternate path by automatic bus transfer. APR1400 applies two automatic bus transfers, so step by step. First attempt at bus transfer is fast transfer. Upon a loss of normal offsite power circuit, a fast transfer is permitted within 100 millisecond if the voltage and phase angle differences between the switchgear bus and alternate offsite power source remains within the acceptable limits, in accordance with NEMA C50.41, by supervising voltage and the phase angle differences between the two voltage sources.

If a fast transfer was not successful, residual voltage transfer will be performed subsequently, after the bus voltage decreases and reaches a subvalue, for instance 0.3pu while the collected motors are coursing down. Voltage decreasing time normally doesn't take longer than one

second. Therefore, APR1400 provides two redundant offsite power supply. One is available immediately; the other is available normally within a second. This design spec meets GDC 17 in terms of offsite power supply access time.

This is a cabling guide taken from Chapter 8, Figure 8.2-1, showing separation of redundant PPS circuits from UAT and SAT 2 Class 1E switchgear buses. Lines in red represent PPS I circuit, and the lines in blue dots represent PPS II circuit. As viewed in this plan, separation between normal PPS and alternate PPS circuits is achieved in practical manner to minimize potential for common cause failures of both PPS circuits.

MEMBER STETKAR: Alex, before you switch this, there's some areas in and around the aux building where you show the normal and preferred PPS circuits, the blue and the red together. I see that there's a wall between them in the underground ducts from the transformers to the switchgear room. In the DCD, it only says that separation is maintained by dedicated cable trays. Are the normal and alternate preferred sources routed through the same fire zone after they exit the Non-Class 1E switchgear room and

only separated by cable trays within the fire zones?

MR. KANG: Good questions. Inside of the building, PPS I circuit and PPS II circuit are separated by different cable trays.

MEMBER STETKAR: Okay, but different cable trays could mean here's one cable tray and here's another cable tray, meaning the traditional old horizontal and vertical separation.

MR. KANG: There must be horizontal spatial distance B-

(Simultaneous speaking.)

MEMBER STETKAR: Are they routed through the same fire zone.

(Simultaneous speaking.)

MEMBER STETKAR: Okay, thank you.

MR. KANG: PPS I circuit and PPS II circuit is non-safety

(Simultaneous speaking.)

MEMBER STETKAR: I understand. I'm just trying to understand how they're actually routed, so they are routed through the same fire zone. Can you show me -- I know where the AAC GTG building is located. It's down somewhere over by Rob. How are the cables from -- where is Bus 3N located?

MR. KANG: Bus 3?

MEMBER STETKAR: Bus 3N, the AAC GTG 4 kV -- I love talking like this -- bus, the one that we were talking about earlier.

MR. KANG: You're talking about the location of the AAC building here?

MEMBER STETKAR: Yes, is it located in the AAC GTG building?

MR. KANG: Yes.

MEMBER STETKAR: It is?

MR. KANG: Here, as you can see in the slide, you can see the location -- dedicated location for AAC GTG facility. This is the location of the AAC GTG facility.

MEMBER STETKAR: Thank you. That answers my other question about cable routing, so I'll look at that one. Thank you.

MR. KANG: You're welcome. Open phase condition is one of the most challenging issues of the offsite power system currently being addressed by most nuclear power plants in the world. There are two NRC published documents dealing with this, obviously, BL2012-01 and BTP 8-9, which was published in July 2015. In order to address the obvious issues, KHNP

has performed a design vulnerability study, including sufficient analyses needed to characterize and quantify the safety challenges of OPCs.

As a result of the study, KHNP has determined that a dedicated OPD system is being included on the primary side of power transformers, in addition to the conventional protective relays in the APR1400. The minimum required design features of the OPD systems are detection of OPC over the full range of transformer loading, redundant detection subsystems with voting logic to minimize operation failure or unintended operation of the detection and protection, continuous monitoring and self-diagnostics to main control room. Basically, the OPD system is Non-Class 1E, so it should meet separation requirements, as per IEEE 384 for the interface with Class 1E system.

CO-CHAIR SUNSERI: Just a question here. I don't have my note right in front of me, but I thought I read in the DCD where it said the COL applicant was going to be responsible for the open phase circuit design, but this slide indicates that it's part of the APR1400, I'll call it basic design. Which is it?

MEMBER BLEY: Next slide.

CO-CHAIR SUNSERI: Oh, is it next slide?

MR. KANG: Current COL information 8.12(7) is proposed initially by KHNP, but NRC staff didn't accept our proposal because they consider that our certified design should be sufficient for COL applicant to implement that design, an actual design. We developed our certified design to address the open phase conditions after having sufficient design vulnerability studies. This information -- in the next slide, I will explain. Next slide. This is COL information which has been proposed as a response to the -- we sent our RAI 8521, which was transmitted on November 14 this year.

MR. MANNON: So it's a little of both. What they did is they reviewed which designs would be acceptable, but it's going to be up to the COL applicant to actually choose the exact one they want. We kind of set the criteria, looked to see which ones were available and which ones would be acceptable, and it will be up to them to choose the specific designs since there's a few designs that are out there.

CO-CHAIR SUNSERI: I guess that would be my question is since it is somewhat of a difficult condition to detect and you've done your design

vulnerability study, I would think it would be more reliable, if you will, to just go ahead and design the basic design and include it with the APR1400, instead of letting the applicants try to figure it out, and then have these various designs across the system.

MR. MANNON: There could be a lot of changes in. I think the industry's still redoing some of the designs, which ones are the best, which ones do a better job than other ones. We kind of felt that it would be a little bit more flexible to say if the design advances between now and that time, they could choose a particular

(Simultaneous speaking.)

MR. KANG: According to our study, there are many -- three or four in this OPC solution which are found to be applicable to APR1400 design. Many industries are developing open phase detection systems. We considered that choosing the specific type of OPC solution is better to keep it as COL applicant's scope because at the moment, we don't know which solution is better or more appropriate to APR1400. Instead, we placed a minimal functional requirement, as I show in the previous slide. Then the COL applicant may choose the most appropriate and

better solutions for the open phase conditions.

CO-CHAIR SUNSERI: Thank you.

MR. KANG: So let's consider that open phase condition issue is currently being tracked as an open item, as of today. Considering this issue, KHNP submitted a response to the RAI 8521 according to the rating feedback from the NRC. On this slide, I'll explain about design features of the offsite power system -- onsite power system, sorry. According to GDC 17 --

(Simultaneous speaking.)

MEMBER BLEY: Just to keep our count straight as we listen, the open phase issue is one of two open items, right? It's one of the two that was B-

MR. KANG: One of the two open items.

MEMBER BLEY: Okay, there's only two?

MR. KANG: We have five open items related to two open item issues. This is one of the two open item issues.

MEMBER BLEY: Okay.

MR. KANG: According to GDC 17, the onsite electric power supplies shall have sufficient independence, redundancy, and testability to perform

their safety functions assuming a single failure. Concerning redundancy, the Class 1E onsite power system consists of four trains, A, B, C, and D, and each two trains, A plus C, and B plus D, constitute Division I and Division II, respectively. Between Division I and Division II of the Class 1E system, independence and redundancy is guaranteed.

To properly satisfy single failure criterion, the redundancy equipment of the Class 1E onsite power system is located in separate rooms and different fire areas of seismic Category I building, with adequate independence to assure performance of plant protection and safety functions assuming a single failure. The Category I buildings are designed to withstand the effect of natural phenomena.

The Class 1E onsite AC power system is designed to conform to single failure requirements per IEEE 603. Concerning independence, Class 1E onsite AC power system is physically and electrically independent of the offsite power system and the Non-Class 1E buses and load. Where there's a need of connection between Class 1E circuits and Non-Class 1E circuits, the connection is implemented by isolation devices, per IEEE 384. Between equipment of redundant

divisions, including cables and raceways, physical separation is maintained in accordance with IEEE 384. Between Class 1E trains there's no electrical connections or load share. With regard to connection interfaces with power source, Class 1E Trains A, B, C, or D has connections to both offsite power circuits from UATs and SATs, and one connection to a Class 1E onsite power source emergency generator.

In addition, each Class 1E Train A and B has connection provisions to AAC source and mobile generators to address a station blackout and beyond design based external events. Respectively, I show in the table. Further details on the APR 1400 SBO coping strategies will be presented by Mr. Kim in the later part of this presentation, and further details on the APR1400 coping strategies for beyond design basis external events will be addressed in ACRS subcommittee meeting for Chapter 19 presentation coming in the next year, but if you have any simple question, I will answer to you as far as my knowledge goes.

When it comes to Non-Class 1E onsite AC power system, then components are 13.8 kV and 4.16 kV Non-Class 1E switchgears, 4.16 kV PNS switchgears, a number of load centers, motor control centers, and the

AAC gas turbine generator, similar to Class 1E onsite power system. The Non-Class 1E onsite power system consists of two divisions, Division I and Division II, which evenly share the plant non-safety electrical load. However, the redundancy and independence requirements do not apply between the Non-Class 1E divisions. Like Class 1E system, Non-Class 1E medium voltage switchgear of each division have connections to both offsite power circuits from UATs and SATs.

Division I switchgears have connections to Division I UAT and SAT. Division II switchgears have connections to Division II UAT and SAT. When the offsite power from the UAT is lost, the alternate offsite power from the SATs is provided by automatic bus transfer. In the event of a LOOP, the AAC gas turbine generator is manually aligned to two permanent non-safety buses to supply essential non-safety load.

This is a partial single-line diagram that just shows the connections of power source available for the Class 1E buses and order of preference in accordance with various operational status of the plant. During normal operation, the Class 1E buses are fed from the main generator to the unit aux transformers. When the main generator becomes not in

service, grid provides offsite power to the Class 1E buses through the main transformer and unit aux transformers. If the normal PPS is not available due to a failure at PPS component or circuits, the alternate PPS takes over power supply to the Class 1E buses through the SATs. In the event of a LOOP, the emergency diesel generators are automatically started and supply power to the Class 1E buses. In the event of station blackout, the AAC GTG that=s manually aligned to the certain bus Class 1E Train A or Train B to cover station blackout condition.

In the event of a beyond design basis external event which involves extended loss of all AC power, including gas turbine generator, mobile diesel generator will be manually aligned to Class 1E medium-voltage bus and low-voltage buses as appropriate. This order of preference of APR1400 onsite AC power supply, where safety function is in line with the defense-in-depth concept of APR1400 safety features.

MEMBER STETKAR: Alex, can you leave that up for a moment? I know it's difficult to see, but I had a couple of questions. There's a section in the DCD that discusses interlocks among the various power supplies. You mentioned that if I lose power from a

unit auxiliary transformer, there's an automatic fast bus transfer to the standby auxiliary transformer. Are there any interlocks that can prevent that transfer?

MR. KANG: Which transfer?

MEMBER STETKAR: UAT to SAT.

MR. KANG: Interlock?

MEMBER STETKAR: Right.

MR. KANG: It's in the transfer between UAT and SAT, there could be manual transfer.

MEMBER STETKAR: No, I'll talk about manual later. I'm talking about automatic transfer. Are there any interlocks that can prevent an automatic transfer?

MR. KANG: For the automatic transfer, there are interlocks between the incoming circuit breakers in the aux transformer and standby aux transformer. That means without opening the incoming circuit breakers in the aux transformer, the incoming circuit breaker in standby aux transformer will not close.

MEMBER STETKAR: Will not close, so the UAT supply has to be open before the SAT closes?

MR. KANG: Correct, yes.

MEMBER STETKAR: Anything else?

MR. KANG: Anything else? In order to permit the fast transfer, the SAT side, there's no partition trip in the SAT side, and the power source must be shown to be available. As I explained, there must be acceptable voltage and --

MEMBER STETKAR: Yes, so it looks over to see --

(Simultaneous speaking.)

MR. KANG: Also, the fast transfer must be completed within 100 milliseconds. That's the conditions for the fast transfer.

MEMBER STETKAR: Okay, thank you. Let me make a note here.

MR. KANG: The alternate side power source must be available, no protection --

MEMBER STETKAR: No protection --

MR. KANG: -- no protection --

MEMBER STETKAR: -- normal supply open before alternate supply closes, and you must complete within 100 millisecond --

MR. KANG: Yes.

MEMBER STETKAR: -- time?

MR. KANG: There's a time delay.

MEMBER STETKAR: Let me -- I'm a slow writer, and I'm old enough that I don't remember anything. Now, in the interlock section, it says that if I want to transfer manually from the UAT to the SAT, I guess that must be a -- I'll call it a slow dead bus transfer. In other words, all of the loads from all of the buses will stop, and I must restart those loads. Basically, I cannot parallel those two supplies.

MR. KANG: Basically, we can bus power.

MEMBER STETKAR: You can?

MR. KANG: Yes, because assuming the PPS I source and PPS source have the same grid source, normally the phase angle differences is not significant between the two sources.

MEMBER STETKAR: Okay, but the reason I had the question is there's a statement in the DCD that says, "The interlock circuits of the incoming breakers prevent parallel operation between normal and alternate preferred power supplies during manual transfer between UAT and SAT." It says prevent. I had a question that if I have -- if my phase angle and everything else is fine, why can't I parallel them?

MR. KANG: You're talking about the phrase

in Section 8.3.1.1.3.4?

MEMBER STETKAR: Yes.

MR. KANG: This is interlock between EDG breakers and --

MEMBER STETKAR: No.

MR. KANG: Yes.

MEMBER STETKAR: This is between UAT and SAT.

MR. KANG: This is section 8.3?

MEMBER STETKAR: 8.3.1.1.3.4.

MR. KANG: Yes, electrical interlocks of circuit breaker are provided to prevent the automatic closing of an EDG breaker.

MEMBER STETKAR: But if you look in that section -- and I don't have the page in front of me because I just copied the sentence -- there is a sentence that says the interlock circuits of incoming breakers prevent parallel operation between normal and alternate preferred power supplies during manual transfer between UAT and SAT. That has nothing to do with EDG breakers.

MR. KANG: You're correct.

MEMBER STETKAR: I don't know what page that's on, but you can find it.

MR. MANNON: The header talks about EDG, and that's a sub-bullet underneath that header, so it may be something that's just --

MEMBER STETKAR: That's why I had a question about why can't I manually parallel those supplies to avoid tripping and restarting every single load supplied from each transformer? Because what you were starting to say is that you could parallel them.

MR. KANG: I'm sorry. I rectify my previous allegation. There is one synchronism tabulated between UAT with the source and SAT source, but that synchronism cycle only permit the transfer when there's no power available one side. That means that dead bus live line or live bus dead line condition, it permits the permission between the two buses.

MEMBER STETKAR: So you either have to have dead bus live line or a live line dead bus?

MR. KANG: It doesn't -- yes.

MEMBER STETKAR: This is a question about the design. Why do you force people on a manual transfer? Because I may have to manually transfer these loads, at least during startup and shutdown for outages. Why do you require people to stop and

restart every single running piece of equipment supplied from those buses for a manual transfer?

MR. KANG: Because of the potential phasing the differences out to PPS sources. We don't know --

MEMBER STETKAR: I understand if they're not synchronized. Then I get it. But if they are synchronized --

MR. KANG: Yes, because of a little bit difference phasing between two sources, there could be some synchronizing currents that nobody knows how much the synchronizing currents may impact or may damage the electric unit. Most --

MEMBER STETKAR: It's okay; thanks. You answered the question. I'm an electrical engineer, so I understand synchronizing.

MEMBER SKILLMAN: Before you move on, is the explanation that you just provided also applicable to restart after a station blackout? I would think that it is. You're going to have to manually go on to dead buses to bring the equipment back on to service.

MR. KANG: After a session blackout, we have to recover the onsite power system by using emergency diesel generator or using recovered offsite

power source.

MEMBER SKILLMAN: Okay, just hold on. You've completed your station blackout. You now have offsite power. Your relays prevent bringing in offsite power because you're powering with your onsite sources. Is the process to halt your -- whatever engine is providing your local power, and then do a dead bus restart from offsite?

MR. KANG: It must be, the process has to recover the onsite distribution system upon a recovery of offsite power system must be included in the emergency operation guide.

MEMBER SKILLMAN: Okay, that's fair.

(Simultaneous speaking.)

MEMBER SKILLMAN: Okay, thank you.

MR. KANG: Section 13.6 may deal with the emergency operation guide. The Class 1E onsite DC power system consists of four trains, the same concept as the Class 1E onsite AC power system being supplied from Class 1E onsite AC power supply of the same train.

Each train of the Class 1E DC power system supplies reliable 125 DC power to various plant safety equipment, such as motorized valves, solenoid, NSSS

and BOP Class 1E control and instrumentation systems, IP inverter. Each train of Class 1E DC system consists of battery, battery charger, DC control center, and distribution panels.

In particular, redundant battery chargers are designed which allows for online maintenance of a battery charger without degraded operation below icier condition, the concern about redundancy, independence, and single failure criterion for the Class 1E. This system is the same Class 1E AC power system. Redundancy and independence is maintained between Division I and Division II. The Class 1E DC power system components of each train are located in dedicated locations of a quadrant division arrangement. There is no interconnection or load share between trains. Physical separation between the trains meets separation requirements according to IEEE 384.

MEMBER SKILLMAN: Let me ask you a question on that image, please. You show an inverter. I'm presuming that is a solid state inverter.

MR. KANG: Sorry?

MEMBER SKILLMAN: You show the image of an inverter.

MR. KANG: Inverter?

MEMBER SKILLMAN: It's approximately to the lower middle part of that image, inverter. I'm presuming that is a solid state inverter, Inverter 1 Alpha. Do you see?

MR. KANG: Inverter here?

MEMBER SKILLMAN: Yes, see inverter, just to your left, right there.

MR. KANG: Inverter, yes. This inverter is dedicated inverter for motorized valve.

MEMBER SKILLMAN: Okay, just let me ask my question. In this design, what was the consideration for an inverter, which is basically a solid state device, versus a converter, which is a motor driven by AC that develops DC? There has been history in parts of the industry where the solid state inverters are significantly less reliable than the old converters that were basically an AC motor that was driving a DC generator.

MEMBER STETKAR: Where's that operating experience? Because my experience has been solid state is a hell of a lot more reliable than the old rotating converters.

MEMBER SKILLMAN: It's dated from 20 years

ago.

MEMBER STETKAR: Yes, when they didn't have many modern solid state inverters. I've seen solid state inverters that --

MEMBER SKILLMAN: 100 percent reliable -- 99.9?

MEMBER STETKAR: Come now.

MEMBER SKILLMAN: Okay, 98.8? You're saying high, really good?

MEMBER STETKAR: Better than the rotating machines.

MEMBER SKILLMAN: Charlie, is that square with your background?

MEMBER BROWN: It depends on what you mean by it generating DC and what you have to --

MEMBER STETKAR: No, this is generating the AC from the DC motor.

MEMBER BROWN: If you've got a DC motor that's running with brushes and everything else, it depends on how you --

PARTICIPANT: Maintain it.

MEMBER BROWN: -- how you live and love with the brushes. You have to maintain them. If you've got a good system that can keep the carbon dust

out of it --

MEMBER SKILLMAN: It runs forever.

MEMBER BROWN: -- which I only know that because I had to compensate for a disaster in the 688 submarines at one time. We completely redesigned it to separate, and we weren't spreading the carbon dust throughout the entire AC and DC motor parts -- generator and motor parts. Once we did that and we filtered it, didn't let it circulate, then it came out okay. But if you have a mixed airflow, it's a disaster. I would agree with John that the solid state ones are better. I've also had solid state inverters that explode on you.

MEMBER SKILLMAN: Right.

MEMBER BROWN: They're not 100 percent reliable.

MEMBER SKILLMAN: No, they are not.

MEMBER BROWN: However, we used --

MEMBER SKILLMAN: That's the experience that I'm --

MEMBER BROWN: The ones we built in the late '60s -- excuse me, the late '90s -- the ones we were putting in some plants with the new power semiconductors, if you design them right, we did not

have any problems at all with them. They were very, very, very reliable. We backfitted some motor generator sets with solid state NG sets off the battery in order to alleviate and improve the reliability of our AC to DC conversion because of the criticality when the reactor shuts down.

MEMBER SKILLMAN: Okay, I'm good.

MEMBER BROWN: New stuff is very, very good, and the stuff in the ones in the last ten years, the components are very robust.

MEMBER SKILLMAN: Very good, thank you.

MR. KANG: Thank you.

MEMBER SKILLMAN: Thank you.

MR. KANG: In my opinion, every component within the Class 1E must be considered in the PRA study, and the PRA study, every component will be considered as failure rates, something like that. If we have problem in the high failure rates, it must be considered in the PRA.

MEMBER SKILLMAN: Thank you.

MEMBER BROWN: I'll make one other -- Dick, I'll make other comment on the solid state stuff. The only place where we really had that you brought a problem with the -- you had to really design

the solid state AC SATs for harmonic. If you didn't get the harmonics -- you had a very clean AC, it was much easier with an AC generator than it was with a solid state power converter. That makes the systems very much more complex, but also a little more susceptible to temperature, so you don't want to put them in a little, confined space.

PARTICIPANT: Absolutely true.

MEMBER BROWN: Anyway, I forgot that little point. Excuse me.

MEMBER SKILLMAN: Good, thank you.

MR. KANG: It's the division of the Class 1E 125 volt DC battery has adequate capacity without chargers to supply the worst case operating load for a period of battery duty cycle, but for Trains A and B, the batteries are sized to be 2,800 ampere hour for eight-hour-long duty cycle. For Trains C and D, the batteries are sized to be 8,800 ampere hour for 16-hour-long duty cycle. Sixteen-hour-long duty cycle without load shedding is considered for Trains C and D batteries to support Trains C and D plant equipment, for instance, turbine driven aux feeder water pumps during an SBO and beyond design basis external events which involves extended loss of all AC power.

With load shedding at eight hours from the onset of a station blackout, the depletion time of Trains C and D batteries can be extended to 40 hours to support operation of turbine driven aux feeder water pumps during the beyond design basis external events.

MEMBER STETKAR: Alex, in the SER, I read that load shedding is required to extend the life of the Train A and B batteries to eight hours. Is that correct?

MR. KANG: Correct.

MEMBER STETKAR: That is correct? Why is that not noted here? If it is, is that automatic or manual load shedding?

MR. KANG: It's manual load shedding.

MEMBER STETKAR: Okay, I would like to know what loads are shed on A and B batteries and when they are shed. You don't have to -- if it's a long

(Simultaneous speaking.)

MR. KANG: Shedding time is two hours.

MEMBER STETKAR: Two hours?

MR. KANG: Yes. List of shedded increments are listed in the table provided in DCD Tier 2. Let me check.

MEMBER STETKAR: No, that's not -- that may be in a revised table. It isn't in --

MR. KANG: Revised table --

(Simultaneous speaking.)

MR. KANG: Yes, revised table.

MEMBER STETKAR: You have to realize that we -- although we have access to all of the RAIs, we don't have the time to read everything. I'd like to just simply know what loads are shed and at what time. If you have the RAI, we can find it.

MR. KANG: We will check the RAI --

MEMBER STETKAR: Check the RAI number and get it to me. I can look it up. I just don't have it. Thank you. But it is manual, it's not automatic?

(Simultaneous speaking.)

MEMBER STETKAR: And it's at two hours, you said?

MR. KANG: Right, correct.

MEMBER STETKAR: Okay, thank you.

MR. KANG: The Class 1E 120 volt AC instrumentation and control power system assures that the IP system supplies reliable, uninterruptible 120 volt AC power to the plant safety I&C equipment, such as safety consoles, plant protection system, ESF-CCS.

Major components of Class 1E IP system are inverter, regulating transformer, automatic and manual transformer switch, distribution panel.

They have sufficient capacity and capability to perform their intended functions. The Class 1E 120 volt AC IP power provides normal and alternate feeds to the power distribution panel. Normal feed is supplied from the inverter, which is backed up by battery. Normal feed is supplied from MCC to regulating transformer, which has no battery backup.

MEMBER MARCH-LEUBA: Alex, can we go back to the batteries? If I'm reading this here correctly, it says that if you do not load shed, the batteries will last for two hours. If you do the transfer and remove the loads after two hours --

MR. KANG: More than two hours. At the time of load shedding, at two hours, additional sixty hours deflation time, the power is available additional sixty hours from the timing of the load shedding. Without load shedding, it could be more or less four hours. The SER is confusing on the thinking, but in the duty cycle, we have already considered the load shedding at two hours, so

qualified load profile has considered load shedding at two hours.

There also exists Non-Class 1E DC power system in the APR1400 design across the whole APR1400 plant side boundaries there are five Non-Class 1E DC control centers. I've shown you the table. Also, there are two standby battery chargers to enhance availability of the plant operation. One is for 250 volt DC; the other is for 125 volt DC. This is a conceptual diagram, which it helps to understand operation characteristics of the DC and IP power supply.

MEMBER STETKAR: Alex, before we get into this, which is going to be some switching, I've also read, again in the SER, that load shedding is required to achieve the -- I'm going to talk about non-1E, so keep it on the non-1E -- that load shedding is required to achieve the duty cycles that are listed for the non-1E batteries, in particular, eight hours for the Division I, eight for Division II, eight for the compound building, and four for the AAC GTG. Is that correct, that loads must also be shed from the non-1E batteries?

MR. KANG: I don't recall if load shedding

is necessary for Non-Class 1E batteries or it's not, so let me check and get back to you.

MEMBER STETKAR: Check with that, please, because I started with the non-1E just because it was first in the SER. It seemed pretty clear in there that load shedding was required to achieve those non-1E duty cycles. In particular, it was focused mostly on the Division I and Division II loads. Could you check that, please, and confirm that? Thank you. Also, if it is required, is it automatic? Is it manual? What times and what loads?

MR. KANG: During normal operation, DC load and IP inverter are supplied to battery chargers. In case of a failure of AC power or battery charger, battery discharges and supplies DC load and IP inverter with no interruption. If the failure is limited to battery charger, the failed battery charger is replaced by a spare battery charger, and the operation mode returns to normal operation. In case of IP inverter failure, the power supply to IP load is automatically transferred to alternate source supplied from MCC to regulating transformer. This degraded operation is limited to 24 hours, according to Technical Specification FC0-387. From this slide, Mr.

Kim will deliver the beginning part of the session summary.

MR. KIM: Okay, may I introduce myself to you so briefly, even though Mr. Kang introduced me in the beginning of the presentation. My name is Seungdae Kim, in the electrical department of KEPCO-ENC. I'm leader of the team responsible for electrical equipment and control circuits. My presentation is divided into two main subjects, emergency diesel generators and station blackouts.

I'm sorry. I started my presentation with emergency diesel generator at first time as emergency sources. EDG is designed in accordance with NRC's Guide 1.9 and IEEE 387. Class 1E EDG power system consists of two redundant load groups, as is shown in the picture, Train A and Train C for Division I, and Train B and Train D for Division II. Each load group has two EDGs. Four 4.16 kilovolt Class 1E EDGs provide backup power to the corresponding Class 1E 4.16 kilovolt buses in the event of a LOOP or a LOOP concurrent with a DBA. EDG unit has minimum target of reliability factor is determined as 0.95, based on Reg. Guide 1.5 and Reg. Guide 1.155. Procedures for monitoring and maintaining the EDG reliability will be

established by COL applicant to verify that the target is achieved. EDG starting signals comes from emergency actuation signals and an under-voltage signal. One of two divisions is sufficient to meet the emergency load requirements for safe shutdown during a LOOP concurrent with a LOCA condition.

MEMBER STETKAR: I don't know when to ask this question, so tell me -- I think it's time now. I got really confused reading through the DCD about LOOPs and LOCAs and design basis accidents and ESF signals. First, I have a simple question. If I lose normal -- if I lose the normal and alternate preferred power supplies to 4.16 kV Class 1E Bus 1A, and only Bus 1A, what happens?

MR. KIM: Tell me once more the last part of your question.

MEMBER STETKAR: On your drawing over there, if I take the left-most bus, which I will call Bus 1A, if I lose the UAT and the SAT supply to that bus, and only that bus, no other bus, what happens?

MR. KANG: Detection of loss of offsite power --

MEMBER STETKAR: No, I want to know if I lose the power supply to that bus, and only that bus

-- I don't want to talk about LOOP. I don't want to talk about LOCA. I don't want to talk about ESF. I don't want to talk about DBA. I want to know what happens.

MR. KIM: Detection on the voltage, including loss of voltage and degraded voltage, it's initiated by under-voltage relay which is connected at the bus. In that case, only EDG will start and connect at the under-voltage bus.

MEMBER STETKAR: Okay, you said it will start and connect. It will start, and it will connect, and will the loads be re-sequenced onto that bus?

MR. KANG: Yes, yes.

MEMBER STETKAR: Okay, is the order of the load sequencing under that condition the same as the order and the timing of the load sequencing that's specified in the DCD for a coincident safeguards actuation with a LOOP? In other words, there is a timing and an order of loads in the DCD that says which load is energized at which bus --

MR. KIM: That's in the table.

MEMBER STETKAR: That table; that's right.

(Simultaneous speaking.)

MEMBER STETKAR: Is the timing and the loads the same for that condition that I just described, where I have only one EDG loaded to one bus, or is it a different load sequencing?

MR. KIM: It's the same load sequencing.

MEMBER STETKAR: But it is absolutely --

(Simultaneous speaking.)

MEMBER STETKAR: What I'm trying to establish, is there only one load sequencer for each EDG, or is there two? Some designs have two load sequencers and sequence different loads in different order.

(Simultaneous speaking.)

MR. KIM: -- load sequence for each train.

MEMBER STETKAR: Two load sequencers for each -- I will talk about diesels, rather than trains.

MR. KIM: But I think that is different from our design. We have just one --

MEMBER STETKAR: Okay, that's good. I've established that, and it does operate if I only lose power to one, and only one bus.

MR. KIM: Yes.

MEMBER STETKAR: Thanks, that answers most of the longer set of questions. Thank you.

MR. KANG: Rating of the emergency diesel generator has been collected, and it goes to 9,100 kilowatts for Train A and Train B, and 7,500 kilowatt Train C and Train D. These ratings have 10 percent margin, which meets the requirement of the Reg. Guide 1.9. The 4.16 kilowatt Class 1E loads for the EDG Train A and Train C are listed in the table below ,and those for Train B and Train D are identical to Train A and C, respectively.

The only difference between Train A and Train C, Train A has a more of the pumps and 480 volt load, the difference between Division I and Division II is minimal and mainly due to different design conditions for HVAC system. Each EDG with its own control and protection system has no physical and functional interface with other trains. A dedicated and functionally independent load sequencer and control schemes are provided for each EDG. In the event of an accident condition which requires EDG operation, a start of each EDG is initiated, irrespective of the conditions of the other trains. Each EDG is designed to be started automatically and attain a rated voltage and frequency within 17 seconds after receipt of a start signal. Loading sequence

times 5 to 30 seconds represent the immediately after the 17 seconds from the onset of a LOOP, and the EDG output breaker is closed.

The load sequencer automatically sequences the required loads on the Class 1E safety buses, and the required safety-related loads are connected to the buses in the predetermined order and interval time. Each EDG train --

MEMBER STETKAR: Go on. I'll let you finish the slide.

MR. KIM: Okay. Each EDG train and its associated auxiliaries are installed in a separate room, within physically separate seismic Category I structures. EDG support systems, yes, listed here.

MEMBER STETKAR: In the discussion of the EDGs, there are several mechanical and electrical trips that are available when the diesel are being tested. Are those trips blocked whenever --

MEMBER STETKAR: That's the next slide?

MR. KIM: Yes, it's next --

(Simultaneous speaking.)

MEMBER STETKAR: Go back to the previous slide, and we'll talk about this one after you've finished. I'm sorry; I didn't look far enough ahead.

I looked at the load sequence under the fourth bullet there. I noticed that for each of the diesels, the essential chiller is the last load that comes on. Depending on the diesel, that chiller is loaded, I think, either -- let's just use it from here -- 47 seconds.

MR. KIM: Forty-seven seconds?

MEMBER STETKAR: Yes, 17 seconds to start the diesel, get it up to speed and voltage connected to the bus, and then the chiller is the last load that comes on 30 seconds after that, so that's a total of 47 seconds.

MR. KIM: Together 47.

MEMBER STETKAR: I don't know how your chillers are designed. In many cases, I've seen chiller designs that include protective circuits that prevent so-called short cycling of the chiller. In other words, the chiller must be shut down for a fixed period of time before you can restart the chiller. Do your chillers satisfy this requirement that they can be tripped and restarted within 47 seconds?

MR. KIM: Yes, I'm afraid I'm not an electrical engineer, so I --

(Simultaneous speaking.)

MEMBER STETKAR: I understand. Some of the things that we do is to try to connect dots between mechanical and electrical. Take that back --

MR. KIM: I think that's not included in this Chapter 8 --

MEMBER STETKAR: I understand.

(Simultaneous speaking.)

MEMBER STETKAR: But it's also not included in the chapter on the chillers. That's why I asked the question today.

MR. KIM: Yes, you will get answers about your questions when you have the meeting with Chapter 9, so you can ask there.

MEMBER STETKAR: The question is on the table. We'd like an answer to the question; I don't care when.

MR. KIM: That's good?

MEMBER STETKAR: Thanks. I'm sorry, now you can --

(Simultaneous speaking.)

MEMBER STETKAR: -- next slide.

MR. KIM: Very good. All signals of the protective relay trip, except the trip signals listed in the table below, are bypassed during the operation

of the EDG under emergency conditions. All the signals that are bypassed during the operation of the EDG under emergency conditions, those are engine overspeed, generator differential current, manual emergency trip, and the diesel engine stop lever. Alarms from the relays in the table below are provided in the main control room and the remote shutdown room.

MEMBER STETKAR: Now I'll ask the question.

MR. KIM: Okay.

MEMBER STETKAR: If I go back to the condition that I asked you about before, where the diesel starts and loads only because of undervoltage on its bus B-

(Simultaneous speaking.)

MR. KIM: -- yes, that's Bus A1.

MEMBER STETKAR: -- only because of loss of voltage on its bus, are all of the normal trips bypassed under that condition, also?

MR. KIM: No, except for --

MEMBER STETKAR: Yes, except for the four, but everything below --

MR. KIM: Yes, that's right.

MEMBER STETKAR: Okay, thank you. I

thought that was probably the case, but I just wanted to confirm. Thank you.

MR. KIM: You're welcome. Now, I want to present about AC gas turbine generator that's there to be operable during a LOOP. Two permanent non-safety buses are provided by the 4.16 kilovolt Non-Class 1E AC gas turbine generator during a LOOP. Automatically started by starting signal from an under-voltage relay and manually connected to the two permanent non-safety buses during a LOOP.

AAC source rating is adequate to meet the load requirements during LOOP conditions. We calculated the load sums for major PNS loads during a LOOP. The selected AC/DC rating envelops those amounts of PNS loads during a LOOP. In this part of my presentation, I want to make a presentation about the equipment layout.

As shown in the pictures, each train of the Class 1E power system located in seismic Category I structure is separated so that a single failure does not cause multiple malfunctions or interactions between trains. No interconnection or inadvertent closure of the interconnecting devices between redundant divisions. The physical separation between

the redundant equipment, including cables and raceways, is designed in accordance with IEEE 384. Cables of each train run in a separate raceway, so physically separated from cables of the other trains, and so do raceways. Now, I want to make a presentation about the station blackout.

According to 10 C.F.R. 50.63, sufficient capacity and capability to ensure that the core is cooled and appropriate containment integrity maintained in the event of a station blackout for the specified duration. Acceptable capability to withstand a station blackout, provided an analysis is performed, which demonstrates that the plant has this capability from onset of the station blackout until alternate AC source and required shutdown equipment are started and lined up to operate.

If the AC source is aligned to the shutdown bus within ten minutes of the onset of the station blackout, then no coping analysis is required. The 4.16 kilovolt Non-Class 1E gas turbine generator is designed in accordance with 10 C.F.R. 50.63, Reg Guide 1.155, and the NUMARC 87-00. During an SBO, the AAC GTG with sufficient capacity, capability, and reliability provides power for the set of required

shutdown loads to bring the plant to safe shutdown. In this case hot shutdown. When two, Train A and Train B, of the four EDGs are unavailable during a LOOP in the APR1400, the AAC GTG shall be manually aligned. As shown in pictures, manually connected to the designated 4.16 kilovolt Class 1E switchgear, Train A or Train B, by the operator within ten minutes from the beginning of the SBO event.

Connection from the AAC GTG to the shutdown buses via two normally open circuit breakers. SBO coping duration is 16 hours, as determined conservatively, based on the Reg Guide 1.155. EAC configuration group is determined as Group C because we have two EDGs to be operated during these events and just one EDG is required to be operable, so we select Group C. As presented in the previous page, EDG reliability is 0.95. Offsite power design characteristics group is determined as P3, conservatively, so it comes 16 hours in SBO coping duration.

MEMBER STETKAR: Keep this up. I have three questions that I'd like to ask about this. Are all of the circuit breakers that are in the highlighted area -- can they be operated from the main

control room?

MR. KIM: Yes, that's right.

MEMBER STETKAR: So the breakers at the AAC GTG B

MR. KIM: Yes, yes.

MEMBER STETKAR: Okay, good, thank you. Hold on.

MR. KIM: Okay.

MEMBER STETKAR: As I said, I'm a slow writer and a forgetful person.

MR. KANG: That's why ten minutes alignment is made possible.

MR. KIM: Yes, we just have one hour.

MEMBER STETKAR: You don't have a slide on this, so I wanted to talk about it here. When you talk about recovering from a station blackout -- so we had a station blackout. The AAC GTG starts, and let's say it's aligned to Bus A.

(Simultaneous speaking.)

MEMBER STETKAR: It says that if I restore power from offsite, let's say, from the UAT or the SAT, I manually control the AAC GTG, parallel it with the offsite supply --

MR. KIM: Yes.

MEMBER STETKAR: -- close the offsite breaker, and then open the GTG breaker. That's basically a live bus parallel transfer. It says that if I restore power from an EDG, that must be a dead bus. It says that I disconnect the AAC GTG, and then connect the diesel generator. My question is similar to the question before. Why? Because then I have to restart all of the equipment powered from the bus. Why can't I parallel those two supplies if I connect -- if I restore power from an EDG?

MR. KANG: Basically, to my knowledge, two diesel generators are not so easy. One is not diesel generator. One is AAC gas turbine generator, but there is much more constraints in the diesel generator or gas turbine generator.

There is fighting over power, and there is some concerns on frequent maintenance. That means in order to maintain the rated frequency, that's not so easy. Basically, when emergency AC source is available at the station blackout, it's better to stop the AC source, and then load the sequencing by energizing the emergency diesel generator.

MEMBER STETKAR: Thanks. What I was trying to probe is basically how stiff a supply is the

gas turbine generator compared to the diesel. I'm familiar with problems with diesels and diesels. I didn't know --

MR. KANG: Between diesels and diesels, there could be some problems.

MEMBER BROWN: But diesels and AC generators, we really didn't do that, either, for the same thing. A stiff bus -- a diesel bus is not as stiff --

MEMBER STETKAR: Yes, how stiff this gas turbine is.

MEMBER BROWN: Even the gas turbine generators, there's a few of those that we've had in the other part of the Navy, and they are not as stiff as other ones, but they're still stiff enough to create problems.

MEMBER STETKAR: Yes, okay. Good, thanks. No, that's good. That's a good answer. I'm done. I'm happy with that one. No more questions on that one. I have one more question. I'd like to keep the picture up here. This one's a little more complicated. I understand that if I have only a loss of offsite power, offsite power goes away, and Diesel Generators A and B both work, then the AAC GTG is

connected to both of the PNS buses, 1M and 1N. There's a statement, it says, "The PNS switchgear supplies power to the central chiller, central chilled water pump, and 480-volt load centers, which are required to operate in a LOOP condition. Now, I start thinking about different combinations of things that can occur. Suppose I have a LOOP and Diesels C and D work, and Diesels A and B, and only A and B, do not work. So I have Safety Buses C and D energized. I have Safety Buses A and B de-energized, and I have no offsite power. What do the operators do then?

MR. KIM: In that case, in our APR1400, it's a station blackout.

MR. KANG: Basically, we considered only A and B emergency diesel generator, and A and B bus has the capability to perform safe shutdown because only Train A and B, the shutdown cooling pumps are connected.

MEMBER STETKAR: So that's considered a station blackout.

MR. KIM: Even though we have C and D B

MEMBER STETKAR: Got it. Okay, I understand that philosophy.

(Simultaneous speaking.)

MEMBER STETKAR: Just out of curiosity, since the -- you say the chiller and the chilled water pumps and some 480-volt load centers are required to operate in a LOOP, what do I lose when I lose those non-safety chilled water and ventilation systems? What problems can I have?

MR. KANG: Main functions of chilled water is chilled water supplies -- chilled water system, so central chilled water system supplies chill the water for reactor containment of building HVAC.

PARTICIPANT: Yes, that's right.

MR. KANG: Reactor containment building HVAC shall be maintained below 150 degrees Fahrenheit during normal operation. If you lose central chillers during a LOOP, heat inside of the reactor containment building -- heat will accumulate, so that's not so good from safety point of view. This is the main function of the central chiller, to maintain -- to supply reactor containment building HVAC chilled water -- by supplying chilled water.

MEMBER STETKAR: That's, you say, the main function. Does it supply any other function out in the turbine building or other areas of the plant?

MR. KIM: Yes, they send chilling water to

HVAC system.

MR. KANG: The major function is supply --

MEMBER STETKAR: My concern is, here, that if I can -- I can walk you into situations where I have power to half of the plant -- I'll call that the division -- it's hard to see here. I can walk you into a situation where you have equipment energized in the non-safety-related part of the plant, and you have no power at 4.16 safety buses 1A and 1B.

Those combinations are possible -- how likely they are is a different question, but they're certainly possible -- where you have heat loads in the plant that may require ventilation because they're still operating, and yet I have what you're calling a station blackout, since I have no power to 1A and 1B. My concern is what do the operators do under those conditions? Will they only connect the AAC GTG to 1A and 1B -- 1A or 1B.

PARTICIPANT: 1A or 1B, okay.

MEMBER STETKAR: I'll have to think about that. I want to get that straight because now, when we go out into Chapter 9 and talk about ventilation systems, I can think about that more clearly out there. Thank you.

MR. KIM: AAC GTG is started automatically and designed to attain rated voltage and frequency within two minutes after receipt of a starting signal. The loads required for plant safe shutdown are manually connected by the operator in the main control room and remote shutdown room. To minimize the potential for common-cause failures with the onsite Class 1E EDGs, the AAC GTG is provided with a gas turbine engine with a starting and cooling system, according to the requirements of Criterion 2 for Reg Guide 1.155, Position C.3.3.5.

Periodic testing and inspection of the AAC GTG will be implemented according to the requirement of Criterion 5 for Reg Guide 1.155. COL applicant develops the detailed procedures for manually aligning the AAC GTG to the safety buses during a station blackout.

MEMBER BROWN: Before you go on, on the GTGs, when you're manually transferring loads to those, they normally don't respond in recovery. It takes two minutes to become stable frequency and voltage wise. Depending on the size of the load, you can move outside. Is there a requirement for the operators -- training for the operators to put a big

load on, wait for stability, then do the next? In other words, they just don't go click, click, click, click?

MR. KIM: Yes.

MEMBER BROWN: Okay. You understand the disadvantage of the gas turbine B

MR. KIM: The COL applicant will prepare procedures for operational.

(Simultaneous speaking.)

MEMBER BROWN: You answered my question. I just was -- do you have to provide a time frame for certain loads to wait, or is it just based on watching your instrumentation?

MR. KIM: At this time, we don't have comments about your question. That will be prepared by the COL applicant next time.

(Simultaneous speaking.)

MEMBER BROWN: Okay, so somebody will have to figure that out later.

MR. KIM: That's right.

CHAIR BALLINGER: I'd like to just mention that we're getting behind schedule, but we're really not behind schedule because we decided that the question responses, we'll look at those at the end of

the day if we have time, so we're okay with time.

MR. KIM: Okay. Continue?

PARTICIPANT: Yes, go ahead.

MR. KIM: In this part of my presentation, I want to talk about the physical aspect of the AAC GTG and the electrical circuits. AAC GTG and the equipment are installed in a separate AAC GTG building, as shown in the figure. Cables from the AAC GTG to the shutdown buses are separated from the cables from the PPS sources. This is the end of my part of the presentation. Mr. Kang, I'll hand over the presentation again.

MR. KANG: I'm starting to explain about open item summary, a summary of open items of Chapter 8. To date, there are five open items that are being tracked as open items. However, four open items are related to one issue, so practically, there are only two.

MEMBER BLEY: Can I interrupt you and back you up? There was one thing -- I looked through the interlock section. John had asked you what do you do if you have ANC.

PARTICIPANT: Go to Slide 30. It will help.

MEMBER BLEY: -- if you have ANC powered --

PARTICIPANT: Thirty?

MEMBER BLEY: Yes. John asked you if you have A and C powered -- I'm sorry, the other way around, C and D powered, but not A and B, you said you declare it a station blackout, and you've got the gas turbine to take care of that. I didn't see any interlocks discussed that would prevent you from backfeeding through the AAC bus over to another 1E bus. Was there anything that would prevent an operator from doing that?

MR. KANG: Backfeeding B

MEMBER BLEY: From any one 1E bus to another?

MEMBER STETKAR: You can't connect C and D through the gas turbine.

MR. KIM: We B

(Simultaneous speaking.)

MEMBER STETKAR: Oh, I'm sorry; that's right. That's right, you'd have -- but you could come from -- over from the other division -- over from the other division. I lose track of what we called it.

MR. KANG: In this slide, only Train A or

Train B will be connected, not both.

MEMBER STETKAR: Are there -- let's try something simpler. I know that on this slide here, the two circuit breakers to the PNS buses, both of them can be closed at the same time. Are there any interlocks that prevent all four of the AAC GTG bus breakers from being closed at the same time? In other words, can I close all four of those breakers?

MR. KANG: Let us check that and get back to you.

MEMBER STETKAR: Because where Dennis was heading is I could possibly backfeed from a PNS bus through the AAC GTG bus to a safety bus.

MEMBER BLEY: Alternatively, do you have to have the gas turbine --

MEMBER STETKAR: Even if the gas turbine is not available.

MEMBER BLEY: Yes, but do you have to have power at the gas turbine to close any of those breakers? That's kind of an alternative way to ask the question.

MEMBER STETKAR: You see what Dennis is asking about is can the AAC GTG bus be used, essentially, as what some people call a transfer bus,

where I can wheel power to a safety bus from the non-safety side of the plant through there, under these kind of strange conditions?

MEMBER BLEY: Not that you want them to, but could some -- is there anything that prevents that ?

MEMBER STETKAR: That's good because it took us a while to understand it. Sorry to interrupt you. Go ahead where you were.

MR. KANG: To date, there are five open items being tracked as open items, the draft of Chapter 8. Four open items are related to one issue. Actually we have two open-item issues. First one is issue raised by RAI 8426, initially, RAI 7915. Location number is 8.1.14.

The staff requested the applicant to provide explanation as to how the proposed design meets GDC 17 and SECY 91-078 requirements and to discuss how the electrical system provides a direct connection with no intervening non-safety buses from the offsite power source to the onsite Class 1E system.

This issue, KHNP's position is the APR1400 offsite power system has direct connections to the

safety buses without any intervening non-safety buses. SECY 91-078 is on the basis of generator design. The APR1400 offsite power system does include common transformer windings in the UATs and SATs being connected to both safety and non-safety buses, similar to generator design, and also existing nuclear power plants, which did not modify the design. The reason, KHNP considers APR1400 offsite power system design properly complies with the minimum requirements of SECY 91-078. In addition, KHNP has considered additional protection from fault on a non-safety bus provided by two incoming circuit breakers in series at the non-safety buses.

MEMBER BLEY: This is just more of an English-language question, so I don't know who will want to address it. We speak of requirements of SECY 91-078. SECYs aren't usually requirements, but I guess they become requirements when, in your DCD, you say you will meet all their criteria. Is that essentially where we're at on that?

PARTICIPANT: Recognizing SECY's a guidance.

MR. SISK: Dennis, we agree that's -- they're guidance documents until we've stipulated that

they will be --

MEMBER BLEY: You did so stipulate.

MR. SISK: Yes.

MEMBER BLEY: Okay.

MR. KANG: Any comments? KHNP provided a detailed description via a white paper on the design compliance of APR1400 with SECY 91-078 requirements. Currently, NRC Office of General Commission has been reviewing KHNP's submitted position, and currently, KHNP is awaiting NRC feedback on the KHNP position. Another issue was raised by RAI 8184, followed by 8521, Question 08.02-11.

As I explained in the previous slide, this issue is regarding open phase conditions. The RAI question have asked the applicant to provide detail scheme design to detect and automatically respond to open phase conditions, a summary of analysis for ground-fault and OPCs, required surveillance test, ITAAC, etc.

To the RAI, KHNP has performed a design vulnerability study, established the minimum required design feature of open phase detection system, and prepared a DCD mark-up which incorporated the design features of open phase system, necessary COL items and

ITAAC, and provided a formal response on November 14 for NRC staff's review and concurrence. Currently, we are awaiting NRC review and concurrence. Current status of Chapter 8 is on success path for completion on schedule. A draft SER with open items was issued as of October 27, by NRC, containing two technical issues and a path for closing each open item has been discussed with the NRC staff and is being implemented. Changes in Chapter 8, as reviewed and marked up in response to NRC's RAIs will be incorporated into the next revision of the DCD, Tier 2.

Summing up our presentation so far, Chapter 8 adequately describes the design features of the electric power system of APR1400 standard plant. The APR1400 electric power system design complies with U.S. NRC regulatory requirements, properly meets its endorsed codes and standards and, therefore, provides reasonable assurance of reliable operation of the plant, and safety functions for the plant. Thank you. Any questions?

PARTICIPANT: That's it?

MR. KANG: That's it.

CHAIR BALLINGER: Any questions from the committee? This is just never going to end for all of

us.

MEMBER STETKAR: I thought earlier, when you said we always forget, that you were excluding the royal we, but I understand that it was included.

CHAIR BALLINGER: We will recess until five minutes of.

(Whereupon, the above-entitled matter went off the record at 2:43 p.m. and resumed at 2:56 p.m.)

CHAIR BALLINGER: Okay, we're back in session, and now it's the staff's turn.

MR. WUNDER: Good afternoon. Thank you Mr. Chairman, Lady, and Gentlemen of the committee. I'm George Wunder, the project manager assigned to Chapter 8. I am pleased to be joined today by members of the NRR electrical engineering branch. They are Ngola Otto, Sheila Ray, Swagata Som, and Adakou Foli, and they will be giving today's presentation.

MR. WUNDER: A team of seven engineers from the EEB contributed to the staff's SER for Chapter 8. We are most grateful to all of them for their efforts. We'll be discussing each section of the Chapter 8 DCD. We'll go through them in the order in which they appear in the DCD, starting with Section

8.1, which is an introduction and general overview of the electric power system. For that, I will turn it over to Ngola Otto. Ngola, please.

MR. OTTO: Thank you, George. My name is Ngola Otto, and I will be discussing Section 8.1, which is the introduction section. The electric power system consists of both the onsite and the offsite systems and are the source of power for station auxiliaries during normal operations, and a source of power for reactor protection systems and engineering safety features during abnormal and accident conditions.

The staff reviewed the electric power systems design to determine whether it has adequate capacity, capability, redundancy, independence, and testability. Now, I will discuss the open item for this section, which is also the open item in Section 8.2 and 8.3.1, related to the conformance to SECY 91-078.

MEMBER STETKAR: Ngola, before we get into that, because I'm sure we're going to have some discussion over that topic, in Section -- tell me if you're going to get into this later about the categorization of the standby auxiliary transformers.

I don't think you are.

This is all of the open items. Let me ask you about it first. There were some questions about the standby auxiliary transformers. The applicant said they've categorized the standby auxiliary transformers as important safety equipment and included it within the scope of their reliability assurance program that's documented in Chapter 17 of the DCD. I dutifully went to Chapter 17 and looked. Indeed, the standby auxiliary transformers are in that Table 17.4-1, as are the circuit breakers for those transformers, and the circuit breakers from the unit auxiliary transformers, but I could not find the unit auxiliary transformers or the main transformer listed in that table.

I got curious about why the unit auxiliary transformers or the main transformer are not risk significant equipment, while the standby auxiliary transformers are. Did you guys follow up with the applicant on that?

MR. OTTO: We didn't ask the specific -- originally, when we asked the question, we looked at the offsite power systems. Based on our standard review plan, it initially -- the indication was that

the offsite power systems were important to safety, so we did ask some questions on that.

But then when we got a response, then we went back and looked at our current position on that, which is that the offsite power system is not -- GDC 2 doesn't govern offsite power systems. When we did get a response, they explained that. The only components were what they considered safety significance was the standby auxiliary transformer specific components associated with that.

MEMBER STETKAR: In particular, though, the transformers, their circuit breakers, and the unit auxiliary transformer circuit breakers are all considered risk significant. I guess I'll just put the question on the table. I don't know who's going to answer it, but I'd like to know why the unit auxiliary transformers and the main transformer are not considered to be risk significant pieces of equipment that are included in the scope of the reliability assurance program.

In other words, why is it only the circuit breakers for the unit auxiliary transformers and the circuit breakers for the standby auxiliary transformers, and the standby auxiliary transformers,

themselves? Because for the life of me, I can't figure out why one is and one is not, unless somebody made some strange assumptions in the PRA, but that's why I'm trying to understand that significance. I don't know if that's you --

MS. RAY: This is Sheila Ray of the staff. I don't have an answer to your question. We did rely on the reviewers for Chapter 17. I don't know if the applicant has anything to add in relation to that, but we may have to take that question back --

MEMBER STETKAR: Probably not because it probably came out of the PRA somehow, but anyway, it's a curiosity, and I wanted to get it out of the way before we talked about your open item.

MS. RAY: I understand.

MEMBER STETKAR: Thank you.

MS. RAY: We will take that back.

MR. OTTO: Thank you. I'll continue. Compliance with GDC 17 requires that onsite and offsite electrical power systems support functioning of system structures and components important to safety. The Standard Review Plan 8.2 and 8.3 explains that the GDC 17 requirements for the interface between the offsite and the onsite power systems for

evolutionary advanced light water reactor designs are documented in SECY 91-078.

The staff developed SECY 91-078 after reviewing current reactor designs at that time and considering operating experience. SECY 91-078 has the following two requirements: at least one offsite circuit to each redundant Class 1E division, supplied directly, with no intervening non-safety buses, in such a manner that if the non-safety fails, it will not impact the safety; and an alternate power source to the non-safety loads, unless it can be shown that transients associated with the loss of non-safety is less severe than a turbine-trip-only event.

The current design for APR1400 electric power distribution system is fed from the offsite to the onsite systems through the unit auxiliary transformers and the standby auxiliary transformers. Each transformer, UAT or SAT, have two secondary windings, one rated at 13.8 kV, which serves non-safety loads, and the other one rated at 4.16 kV and serves both safety and non-safety loads.

This picture kind of showed, in the right, it shows where the -- from the 4.16 kilovolt second, you're feeding the safety-related buses, and also, in

black, it shows where you're feeding the non-safety buses, just to give you a better picture.

The staff issued an RAI for this open item because the SECY requirements discussed in Slide 5 had not been addressed. In addition, the connection of non-safety and safety systems to the same unit auxiliary and standby auxiliary transformers, specifically shedding of the common winding, creates failures on the -- could create failures and faults in the safety system due to those on the non-safety system. In the response from the applicant, it explained that the power distribution systems are designed in accordance with IEEE 765, and that specific failure on the non-safety could propagate to the safety-related buses, which are fed from the standby auxiliary and unit auxiliary transformer.

They proposed a design change, in order to isolate a potential fault in the non-safety system, where they add an additional breaker on each of the non-safety lines. The next slide shows -- there's a pictorial of where the breakers are being added. Instead of having one breaker for each of the switch gears, you're having two breakers in series.

MEMBER KIRCHNER: Could you elaborate why

that then satisfies your requirement, having two breakers, not one?

MR. OTTO: I'm going to get into that on the next slide.

MEMBER KIRCHNER: Thank you.

MR. OTTO: Basically, we did review the response to the RAI with the proposed design change. We did issue a follow-up RAI on that because we felt like it did not address SECY 91-078 requirements to satisfy GDC 17. Specifically, we're sharing two -- safety and non-safety is sharing the same transformer winding. There was no indication, as far as what the alternate power source is for the system. In SECY 91-078, the staff concluded that feeding the safety buses from the offsite sources through non-safety buses or from a common transformer winding is not a reliable configuration.

In addition, it subjects the loads to transients caused by the non-safety loads and adds additional points of failure between the offsite and the onsite safety loads. In addition, staff does not endorse IEEE 765. Then we did request that they explain how their design meets GDC 17 and SECY 91-078, or provide an analysis to demonstrate that if there's

no need for alternate power source that you can show that the loss of non-safety is less severe than a turbine trip event. It's still considered an open item, at this point. We're just awaiting a response for the RAI.

MEMBER STETKAR: I'm rather confused and -- I'll just leave it as confused for the whole reason for this open item. First of all, as I went back and reviewed the SECY paper, I was primarily concerned with the existing plant designs, where you supply power to a non-safety bus, and then supply power from that non-safety bus to a safety-related bus. Hence the concern of so-called intervening non-safety bus. This plant clearly does not have any intervening non-safety buses. That was the whole concern that prompted SECY 91-078. Okay, they don't have that. I read your concerns. I'll start asking you a few questions.

Suppose I designed my, I'll call them UATs and SATs, with three secondary windings each, and one secondary winding was 13.8 kV non-safety, and one secondary winding was 4.16 kV non-safety, and one secondary winding was 4.16 kV safety, three windings. Would that design be acceptable to the U.S. NRC

staff? I want a yes or a no. You're familiar with all of the criteria, yes or no?

If you can't answer it now, I would like that answer. I would like answer to another question. If I had a plant design where I had what I'll call a single UAT that supplied all four safety-related buses, and only safety-related buses, and a single SAT that also supplied all four safety-related buses, and only safety-related buses, would that design be acceptable to the U.S. NRC? I want a yes or a no. If the answer to those both questions are yes, those designs would be acceptable, I want you to provide me, please, with a reliability analysis to demonstrate why those other designs provide a more reliable power supply than the design being proposed by this applicant. I've got it on the record. You can read it on the record. It's kind of a complicated question.

There's one sentence that I could find quickly in 91-078 that says if they're supplied by the same winding, it may not be the most reliable power supply. If you're basing all of your open items for this design certification on the notion of reliability, I want assurance that, indeed, this is

not a reliable design, and that other designs that would be approved by the U.S. NRC are more reliable. I'll give you those two examples.

MS. ROSS-LEE: I think we'll have to probably take that series of questions away.

MEMBER STETKAR: You will.

MS. ROSS-LEE: I know for a fact we don't have PRA experts here, and one of your questions was reliability analysis. That's certainly outside of the scope of anything that we have currently looked at. We'll go with the transcriber having your questions/concerns on record, and we'll have to find the proper people to follow up with this line of questioning at a later date.

MEMBER STETKAR: Just for the record, in the SER, it says, "The proposed design does not provide capability to minimize the probability of losing electric power at the safety bus. So, indeed, there are apparently reliability or probability arguments being made as part of the staff's open item on this.

MS. ROSS-LEE: Shall we go on to 8.2?

MEMBER KIRCHNER: May I ask another question? The issue, then -- the problem, so to

speak, that you're having with the submittal is the shared windings?

PARTICIPANT: Yes.

MEMBER KIRCHNER: I just want to understand the logic. In your view, that's not meeting the requirements of 91-078 or one of the GDCs?

MR. OTTO: The issue --

MEMBER KIRCHNER: Because 91-078 says intervening.

MR. OTTO: Yes. The issue is the sharing of the common winding. If there's a failure on the non-safety side, it can propagate to the safety side and makes it unavailable.

MEMBER STETKAR: What kind of failure? What kind of failure, in particular?

(Simultaneous speaking.)

MEMBER STETKAR: What kind of failure --

MR. OTTO: If there's a fault or transient.

MEMBER STETKAR: A fault that's not protected by the load circuit breakers on the non-safety bus and the feed breaker to the non-safety bus?

MEMBER BLEY: Including their selective

tripping design?

MS. SOM: If the incoming breaker --

MEMBER STETKAR: Turn your mic on, if you would.

MS. SOM: Oh, sorry. If the incoming breaker is stuck during a fault at the non-safety bus, then that will not trip, and then it will go to the next upstream breaker to the trip. By that time, we do not know whether the fault can propagate through the common winding from the non-safety 4160 to the safety 4160, and so is the transient.

MEMBER STETKAR: What kind of protection is there on the transformer to look at asymmetric loading on the transformer?

MS. SOM: Transformer protection is in the breaker, itself, located in the breaker, itself, with the 86 of the transformer panel, and with the 86, that 86, if that doesn't pick up, then that will pick up the next upstream breaker. By that time, if the upstream breaker picks up the trip, that will trip the downstream breaker. That will trip the generator circuit breaker, so it's going to be a complicated situation that has not been analyzed.

MEMBER STETKAR: Is that more severe and

more likely than a fault in the unit auxiliary transformer, itself, that takes out the unit auxiliary transformer and, with its protective relay, opens all of the load breakers from the unit auxiliary transformer and the generator breaker and the main transformer high side breakers in the switchyard because that's the protection scheme for those transformers?

MS. SOM: Yes.

MEMBER STETKAR: I submit that the faults in the transformer, itself, are a heck of a lot more likely than your combination of a fault with a failure of a detection of the load breaker and the high side breaker to the bus. That's why I'm asking about reliability. Are we trying to force someone to install systems that comply with someone's interpretation of a SECY paper that, indeed, are less reliable than the system that they've proposed? I'm really concerned about that, so that's why I'm asking about reliability.

MR. MATHEW: This is Roy Mathew from Electrical Branch. I just wanted to clarify specific open item issue. This is not subject to debate right now, whether it's an issue or not. This is an open

item because the commission has directed the staff to look at this evolutionary design for the new plant to be better than the current plants. The current plants have this feature. We are not saying the current plants have a problem.

Commission has directed staff to look at this policy. We are identifying this as open item because the commission policy clearly states that we have to follow this requirement to comply with GDC 17. It could be a reliability issue if it's a common transformer. Staff is saying -- staff is not comfortable saying it meets the commission policy. We have to close the loop by looking at, in detail, the common design for supplying non-safety and the safety loads are acceptable, and also the design prohibition that the non-safety loads have to be fed by an alternate power source, but two requirements commission specifically said the evolutionary plans have to meet. These two issues, we're going to look into more details to see whether it's acceptable, so it is still an open item.

MEMBER BLEY: I think it's good that you look into these issues. I think the questions Mr. Stetkar posed for you are key to understanding what

seems to be claimed in the SER. I just wanted to make one comment, because in the SER, when you refer to GDC 17, you come up with this phrase that the design does not provide capability to minimize the probability of losing electric power at a safety bus. That's not from the GDC.

That's from the SRP, in which there's a more thorough statement, "Provisions to minimize probability of losing electric power from the remaining supplies as a result of or coincident with loss of power generated by the nuclear power unit or loss of power from the onsite electric power supplies." To judge whether you meet this or not, you can't just say it a priori. You've got to do some work to prove that. I think if you look at the whole statement in the SRP, it's even going to be more difficult to prove. I don't think, at least for me, what's written in the SRP doesn't meet -- doesn't prove the case it's trying to make in the SRP.

MS. RAY: I think we understand your comments and your questions on reliability. We don't have those answers now, but we will provide you those answers on the reliability. Would you like me to move on to 8.2, or were there other questions? Continue.

MEMBER STETKAR: We have a five-second rule here. If there's silence for five seconds, move on as fast as you can.

MS. RAY: Slide 10. My name is Sheila Ray, and I will be talking about the offsite power system.

MEMBER BLEY: I'm sorry, since you -- John moved you ahead. He made this point, but it still bothers me that in your slide -- you don't do it in the SER, that I recall -- in your slide, you claim that feeding from the same winding of a transformer, the non-1E and the 1E, is equivalent to having an intermediate non-1E bus. I can't see that. That doesn't meet anything that makes sense to me. We're not feeding from there. The argument that you could have something happen on the non-1E side that affects the 1E has to consider all the protections that are available in the non-1E side, not just say that something could feed back and cause problems.

MS. RAY: Correct. I don't think we intended to --

MEMBER BLEY: The slide says that.

MS. RAY: I don't think we intended to compare non-1E feeding 1E versus a common transformer

winding. Our intention -- I apologize if it wasn't clear -- was not to compare them as one being more reliable or not. We were following the SECY and the guidance in the SECY. The offsite power system is the preferred source of power during normal, abnormal, and accident conditions. The function of the offsite power system is to provide sufficient capacity and capability to ensure that the SSEs important to safety perform as intended.

The offsite power system contains the following components: transmission, switchyard components, main generator and associated components, and transformers. The boundaries between the offsite power system and onsite power system are the incoming circuit breakers of the switchgears, which are included in the onsite power system. Staff reviewed the offsite power system to ensure that it will perform its design function during all operating and accident conditions. Specifically, staff reviewed the offsite power system to determine whether the system supplies power from the transmission network to the onsite power system via two separate circuits, has adequate capacity and capability to supply power to all safety loads, has both physical land electrical

separation to minimize the chance of simultaneous failure, and includes an interface with an alternate AC power source for safe shutdown in the event of an SBO.

One notable area of review was the audit on methodology and assumptions of the isolated phase bus and generator circuit breaker. The staff verified that for the calculation of fault current, fault locations were chosen to produce fault currents from the grid source, generator, UATs, and combinations thereof.

This was to ensure that equipment can accommodate the maximum amount of fault current flowing through the isolated phase bus and generator circuit breaker. The staff verified that the calculation concludes that the generator circuit breaker has the capability of interrupting the maximum asymmetrical and symmetrical fault current. Furthermore, the staff concluded the methodology used conforms to the guidance in SRP 8.2 and the associated industry standards. The first open item has been discussed previously, in Section 8.1. The conformance to SECY 91-078 pertains to the offsite power system, as it shall supply power to the Class 1E buses without

any intervening non-1E buses.

The second open item relates to Bulletin 2012-01, design vulnerability in electric power systems, that is open phase conditions. GDC 17 specifies that the offsite power system shall have sufficient capacity and capability. Currently, the APR1400 design has a COL item for the COL applicant to design the offsite power system to detect, alarm, and mitigate against open phase conditions.

The staff finds that in order to meet GDC 17 and 10 C.F.R. 52.47, the applicant should provide information in the DCD on how the electrical system design would detect, alarm, and respond to open phase conditions. Staff has received a response on November 14th and is currently reviewing it.

MEMBER BLEY: Is the staff, at this point, prepared to discuss, at all, the concept of reserving resolution of this for the COL?

MS. RAY: Currently, I'm not prepared to comment on the response. I will have to get back to you.

MEMBER BLEY: It seems reasonable to me that you ought to have a particular offsite power system in mind if you're going to put this in place,

but we'll see what you have to say after you've finished.

MS. RAY: I'll turn it over to Swagata now to discuss onsite power systems.

MS. SOM: Hi. My name is Swagata Som. The safety function of the onsite AC power system is to provide sufficient capacity and capability, same as we are talking about, because it is the GDC 17 requirement to ensure that the SSCs imported to safely perform as intended. I have two bullets.

The first one is the onsite AC power system includes four trains, with Trains A and C for Division I, and Trains B and D for Division II. There are two UATs and two SATs that supply power to non-safety and Class 1E switchgear, and four Class 1E EDGs and one GTG for SBO. The staff evaluated the system for redundancy, functional independence, physical separation, electrical isolation, and testing capability.

MEMBER BLEY: I have an odd question. I don't know where to ask it. I don't think there's a right place. Somewhere in the early part of the DCD Chapter 8, they say that GDC 5 is related to the sharing of SSCs. There are no shared SSCs because the

APR1400 design is a single unit plan. I've got a comment and a question related to that. I kind of know that they don't have a buyer in the United States, so it's not quite an issue, but if they ever did, somebody might want a two-unit plant.

I see it's buried here in the Chapter 8 part of the DCD. Is it somewhere else? How do you track that, in case after this is -- we'll assume it gets certified -- somebody comes in that's going to have a two-unit plant, and here we've got this buried in Chapter 8?

MEMBER STETKAR: That's good because it would have to be buried in some other chapters, too, for shared cooling water systems or whatever they want to do.

MEMBER BLEY: It ought to be, yes. I haven't read those. It seems to me it ought to be right up front as a big thing. I don't know what you folks do with that, so I'm just curious about it.

MS. RAY: I can only speak to Chapter 8. I might defer to the project manager on process.

MR. WUNDER: Yes, it's throughout the entire DCD. It's addressed in every chapter that I've got.

MEMBER BLEY: It does come up everywhere? Okay.

MR. WUNDER: Yes, it comes up everywhere. What they'd have to do is -- if someone comes in, what they'll have to do is they'll have to take a departure.

MEMBER BLEY: I was just worried that it might be buried.

MEMBER STETKAR: The problem is the chapters -- this is the first chapter that we've seen at the subcommittee level --

MEMBER BLEY: Where it comes up.

PARTICIPANT: Is that right? Okay.

MEMBER STETKAR: -- where you have some -- the other chapters we looked at were Chapter 10, Chapter 4, Chapter 5, those types of things, that are unit specific. We haven't looked at Chapter 9, for example, yet.

MEMBER REMPE: But this is the point -- that's why I was asking about the multi-unit plants at the beginning of this talk that they built. They said it's 98 or 99 percent similar, whether it's a multi-unit or a single unit. But I agree with your point. The same thing came up earlier about load

following. I really think there's a lot of assumptions in the DCD that it would be good -- that whatever the staff finally produces in the draft SE that they identify these assumptions that are different than what you see, sometimes, that are buried throughout the text. Again, this is the first time I've been involved in one of these from the very beginning. It just seems like there are a lot of issues that way.

MS. SOM: So as George said, that we have -- this is Swagata Som. The safety evaluation, we have written that, however, GDC 5 may be applicable to a single applicant that references the APR1400 design if its application includes multiple units. That is there in the safety evaluation.

PARTICIPANT: Thanks.

MEMBER STETKAR: Before you go to DC, I had one question on 8.3.1. There's a section in the SER that addresses compliance with 10 C.F.R. 50.34 for the TMI action plan. In there, there's a discussion that says, "Additionally, the staff verified whether the APR1400 design provides emergency diesel generator standby power supplies for the pressurized relief valves, block valves, and level indicators. The

applicant stated that for the APR1400 design, there is no power-operated relief valve or block valves which requires any electrical power. That may be true in the very narrow sense of the way that we think of pressurized or PORVs for currently operating plants, but their pilot-operated safety relief valves have a number of motor-operated valves associated with them.

There are motor-operated valves that isolate the spring-loaded pilots, so that if I have a spring-loaded pilot that's leaking, I can close that isolation valve and the pilot-operated safety relief valve will then re-close. There are two motor-operated valves in series that I, as an operator, can open, and I'm instructed to open, I guess, if I want to establish feed and bleed cooling, or if I want to establish an emergency depressurization.

There are three-way motor-operated valves in the common discharge line from the pilot-operated safety relief valves that are normally aligned to the IRWST and can be re-aligned to the steam generator compartments for an alternate path for, I think it was hydrogen removal. I can't remember which. When I look at the design, all of those things taken

together, to me, seem functionally very similar to pressurizer power-operated relief valves and the functional equivalent of their block valves. Did the staff look at the power supplies for all of those motor-operated valves associated with the POSRVs and the discharge lines and confirm that, indeed, they're consistent with 10 C.F.R. 50.34 and the TMI recommendations?

MS. SOM: My understanding is that the power supplies are available, but I'm not savvy to respond to your other question of the mechanical system and --

MEMBER STETKAR: My question is from the electrical side, did you look at those power supplies to all of those MOVs and make sure that they satisfied the intent of the TMI action plan? In other words, that those valves can receive power from some emergency source. I don't even know whether they're AC or DC valves right now. I don't know whether they come from DC -- whether they're DC motors or AC motors, and whether they can be supplied by emergency diesels or where they're powered from.

MS. SOM: We have not reviewed in that detail for individual MOVs and all. I would not be

able to answer that question, but I can check with --

MEMBER STETKAR: Can you check, please? Because just as I read the SER, it just said that you looked at it and the applicant said we don't have any PORVs or block valves. There's no further -- there's no discussion of well, but you have these other things. There's no RAI that seems to be associated with it.

MS. RAY: We will have to --

MEMBER STETKAR: Follow up, if you could. I'd appreciate that.

MS. RAY: We'll follow up with our other reviewers who have more information on the valves.

MEMBER STETKAR: Okay, good, thank you.

MEMBER SKILLMAN: Before you change that slide, under the first bullet, the second indent, second diamond, you point to ETAP. On Page 875 of your safety evaluation, you provide these words, "The applicant provided information on ETAP. The summary showed all the audits, calculations posted during the audit. The staff reviewed AC system load follow analysis, SC analysis, motor starting analysis, harmonic analysis, bus transfer analysis, and onsite DC SC analysis." Then you point that the DC is going

to be discussed in another portion of the report. You somewhat conclude as follows. "During the audit, the staff observed that all electrical calculations are comprehensive, extensive, and adequately detailed, with background information, assumptions, and methodologies based on the industry standards and procedures.

However, based on the staff's questions on EDG loading, the technical report will be revised. The applicant is also revising the bus transfer scheme table and the bus transfer analysis." It seems like you've given great credit to the thoroughness of ETAP, but you have found some changes that must be made for the result of ETAP to be acceptable, if you will, under General Design Criteria 17. What is it you found that requires change?

MS. RAY: It's not the ETAP simulations; it was the calculations that documented the results and the assumptions. A calculation has a number of different sections, references, assumptions, ETAP results, and then conclusions. I believe in one of those situations, we found an item missing from one of the tables in the report, itself. It wasn't the ETAP that we have the issue with, the ETAP simulation. It

was the corresponding calculation report or summary report.

MS. SOM: The only thing that was missing was a source condition when it was calculating the short circuit -- they were doing short-circuit calculation. They had missed source condition, which is like EDG. They have, later on, added that one. That's why. Finally, they have added everything that we were discussing during the audit. That's why it said that it was -- that methodology and the assumptions introduction, everything was comprehensive, according to what we have reviewed.

MEMBER SKILLMAN: Thank you.

MS. SOM: the staff performed an audit of the various calculations and methodologies related to the electric power system distribution system. The calculations are based on data from a reference plant in Korea. Site-specific studies and calculations will be performed by a COL applicant.

The applicant followed the guidance from industry standard IEEE for such calculation and used the ETAP modeling and analysis tool to model the electrical systems and conduct simulations. Staff reviewed the data, acceptance criteria, analysis, and

results of calculation, including short circuit, load follow, bus transfer, motor starting and equipment sizing. The staff found that applicant conforms to established methodologies for industry standards. There is only one open item in Section 8.3.1. We are talking about open items that Mr. Otto has already discussed, so I would like to skip it, unless you have questions to follow up. I will go to the onsite DC power system.

The first bullet talks about what the DC power system comprises of, more precisely, the onsite DC system comprises of four trains of Class 1E 125-volt DC power, four trains of Class 1E 125-volt AC instrument and control power, four trains of Non-Class 1E 125-volt DC power, and one Non-Class 1E 125-volt AC system. I forgot that there is one 250-volt DC power system that feeds the larger DC motors that is of the main generator and the turbine.

Here, also, the staff reviewed the DC system for redundancy, physical separation of safety and non-safety systems, electrical isolation, and meeting single failure criteria. The staff concluded that the design of the onsite DC power system meets the regulatory requirements. There is a special

feature that I talked to, and I'll bring it to your attention. The Trains A and B batteries, and the Trains C and D batteries have different capabilities. The Train C and D batteries have a capacity of 2,800 ampere hour and can provide power for two hours without load shedding, and an additional six hours with load shedding, for an eight-hour duty cycle. Trains C and D batteries are significantly larger, at 8,800 ampere hour. There are two 4,400 battery systems in parallel and can provide power for 16 hours without load shedding.

The Trains C and D batteries serve loads for beyond design basis external events and, as such, are of a different size than the Trains A and B batteries. All the Class 1E batteries are sized and qualified in accordance with the accepted industry standards, IEEE 485 for sizing and IEEE 535 for qualification.

In summary, there are no open items for Section 8.3.2 if we just take the DC system as a whole, but not looking at the Class 1E AC power system, which will follow the open items from the AC system. Now, I will turn the presentation to Adakou, unless you have any question.

MS. FOLI: My name is Adakou Foli, and I will present Section 8.4 on station blackout. The staff reviewed information pertaining to station blackout in the DCD to determine whether the design is capable of withstanding and recovering from a station blackout of a specified duration. The applicant provided a station blackout duration of 16 hours. The staff reviewed the methodology for determining the design station blackout coping duration based on the guidance provided in Reg Guide 1.155.

Specifically, Table 2 of Reg Guide 1.155 85, acceptable minimum station blackout duration for set of parameters associated with the emergency AC power configuration rule, the EDG reliability, and the offsite power design characteristic group. Based on the selected set of parameters in Table 2 of Reg Guide 1.155, the staff determined that the station blackout coping duration for the design is 16 hours, and therefore acceptable.

The staff also reviewed the design station blackout capability. The applicant selected an alternate AC or AAC coping approach that includes a gas turbine generator or GTG. The AAC GTG can be manually connected to the Train A or Train B 4.16 kV

safety buses within ten minutes from the onset of a station blackout. The staff reviewed the AAC power source to determine whether the AAC GTG is not normally directly connected to the offsite power or onsite emergency AC power system, has minimum potential for common mode failure with the onsite emergency AC or offsite power sources, is available within a timely manner, that is one hour after the onset of a station blackout, and has sufficient capacity, capability, and reliability to operate the station blackout shutdown load.

Based on the independence, diversity, availability, capacity, capability, and reliability of the AAC GTG power source, the staff concluded that the AAC power source for the design meets the recommended criteria.

The staff also determined that no coping analysis is required to demonstrate the design station blackout capability since, in accordance with the guidance provided in Reg Guide 1.155, the AAC GTG power source meets the recommended criteria for an emergency power source, and it can be demonstrated by tests to be available to provide power to the station blackout load required to bring and maintain the plant

in a safe shutdown condition within ten minutes of the onset of the station blackout.

The staff therefore concluded that the design has an acceptable station blackout coping capability that is the AAC GTG power source. The staff also reviewed the design capability to recover from a station blackout and determined that recovery is achieved by restoring offsite power or emergency AC power from the Train A or Train B EDG. The COL applicant is required to develop and implement the procedures for restoring offsite power or emergency AC power, in accordance with Reg Guide 1.155. In summary, there are no open items for Section 8.4. This concludes the staff presentation. We will be answering questions. Thank you.

CHAIR BALLINGER: Any other questions from the committee?

MEMBER POWERS: You concluded the station has a coping time of 16 hours?

MS. FOLI: Who reviewed it?

MS. RAY: Can you repeat the question?

MS. FOLI: What was the question?

PARTICIPANT: Concluded.

MEMBER POWERS: You concluded the design

has a coping period of 16 hours.

MS. FOLI: Yes.

MEMBER POWERS: Does the design preclude extending this to longer times?

MS. FOLI: No.

MEMBER POWERS: So it could -- a specific licensee could extend this to 24 hours?

MS. FOLI: Yes, after the COL applicant is required to validate the station blackout duration with actual parameters, once the plant is designed and the stat is selected.

MEMBER POWERS: If he finds that he needs 24 hours instead, he can make, without tearing down concrete walls and the like, changes to achieve that kind of a coping duration?

MS. FOLI: The Reg Guide 1.155, methodology in the Reg Guide is limited to 16 hours, so the applicant would have to demonstrate that they can achieve a 24-hour station blackout duration. The plan can withstand station blackout for 24 hours, basically.

MEMBER POWERS: Yes, can he do it with the existing design, or does he have to tear down concrete walls?

(Simultaneous speaking.)

MS. RAY: I don't think we have an answer to that. Until we do an evaluation, we wouldn't be able to comment on that.

CHAIR BALLINGER: I think I've read it somewhere, but forgotten it. What's the fuel supply length for the gas turbine?

MS. FOLI: Twenty-four hours.

CHAIR BALLINGER: Twenty-four hours?

MS. FOLI: Yes.

MEMBER POWERS: Still doesn't answer my question.

PARTICIPANT: I know.

CHAIR BALLINGER: Okay, any other question?

MEMBER POWERS: We've had incidents which suggest that this might be the design vulnerability considered in the future.

MEMBER RAY: I'm just mulling what I just listened to. I guess I -- the certified design, are you saying the coping time is something to be determined later, or to be validated later? What's --

MS. FOLI: The current coping time is actually based on conservative parameters that the

applicant selected, meaning that the stat is not selected yet, the design is not built, so there are some -- one parameter, actually, related to the offsite power system, is only conservative parameter. So once a site is selected --

MS. RAY: Just to clarify or add on to what Adakou is mentioning is the offsite power system information is not available, since it's site specific. The applicant has picked some criteria that's conservative. Similarly for the EDG reliability, they picked a reliability that's, again, conservative, which will be validated at the COL stage.

MEMBER STETKAR: Can I get a clarification that might help? Because we talk about coping times, and I believe that what has been reviewed in this section of the SER is the 16-hour coping time for something that is called an SBO, an SBO being no offsite power, no power from the emergency diesels, power available from the batteries, and power available from the alternate AC generator. Is that correct?

MS. FOLI: Yes.

MEMBER STETKAR: That's the coping time

that they're talking about today. A longer coping time might be needed to address issues of beyond design basis external events with no AC power from any source available. Is that correct?

MS. FOLI: Yes.

MEMBER STETKAR: Is that coping time reviewed as part of Chapter 19?

MS. FOLI: Yes.

MEMBER STETKAR: Okay, thank you.

(Simultaneous speaking.)

PARTICIPANT: I think the answer to your question is they don't know yet.

MEMBER POWERS: That's the answer that I took, but it seems to me -- that's fine. We just need to make sure that the design doesn't preclude reaching these additional things, especially given the flux we have following the events at Fukushima and substantial overreactions.

MEMBER STETKAR: Indeed --

PARTICIPANT: Let the record show that there was muffled laughter.

MEMBER STETKAR: What I'm hearing them say is we'll get a chance to address that issue when Chapter 19 comes to us, right?

MS. FOLI: Yes.

MEMBER STETKAR: That potential need for a longer coping time.

MS. FOLI: Yes.

MEMBER RAY: Has the design been reviewed to assure it has the coping time of 16 hours?

MS. FOLI: Yes.

MEMBER RAY: Because I heard comments that made it sound like we'll have to see. I wasn't sure exactly what you were saying.

MS. FOLI: We did review the 16-hour coping time for this design, for the --

MEMBER RAY: You're satisfied that it will achieve that?

MS. FOLI: Yes.

MS. RAY: There are criteria in -- there's COL items and ITAAC to verify --

MEMBER RAY: Exactly. You're going to require demonstration of 16-hour coping time.

MS. RAY: Correct.

MEMBER RAY: Irregardless of siting issues, if the plant is to be sited at a place where a longer coping time is needed, that's what these guys have been talking about. I was trying to ask whether

there was some uncertainty in the coping time, as certified.

MR. MATHEW: Let me clarify. This is Roy Mathew from Electrical Branch. I think people are a little confused, probably. You're talking about coping period for station blackout, as required by 50.63. The 50.63 requires the applicant or the licensee to follow the requirements specified in Reg Guide 155 or NUMARC 8700 to calculate the coping duration. Coping duration is derived from offsite power configuration and the design of the onsite power system. Based on the design of KPR1400, we know the design of the onsite power system. We know the configuration of the offsite power system. Based on the guidance, we have to calculate the coping duration. If you look at the Reg Guide 155, it says licensees of applicant can choose anywhere from 4 to 16 hours.

The duration calculation has reliability, availability, configuration. All of them are factored in getting that number. The assumption is at the end of 16 hours, the plant will either recover onsite power, or the offsite power. Either one of them will be available by the end of 16 hours. That's what 5063

is.

MEMBER POWERS: You're still not answering the question. The question is does it preclude extending that time?

MR. MATHEW: No. Sixteen hours is based on availability and reliability of the offsite --

MEMBER POWERS: I think we fully understand that. The question is does the design preclude extending that time?

MR. MATHEW: No. As long as you meet 5063, they can extend it. If they want to do it 24 hours, so be it, but 50.63 is clear. Based on the configuration --

MEMBER POWERS: What 50.63 doesn't say, what I want to know is can they extend it without tearing down concrete walls and doing other kinds of major alterations of the system?

MS. ROSS-LEE: That might be a -- I don't know that the staff here can answer the question of tearing down walls and changing configuration. I don't think we have those people here, but I'm sure that question can be taken away. These electrical engineers are not probably prepared to answer changes in actual physical configuration of the plant to

address that. We'll have to get back.

MR. MATHEW: Yes, but 50.63 is clear.

CHAIR BALLINGER: Any other questions?

MEMBER BLEY: Yes, but not a question, a request. I dug back and found an SRM on SECY 91-078, dated April 1, 1991, which, in its conclusion, says, "The commission will continue to review the certification issues presented in the paper, and will address them in a subsequent SRM." My request is is there a subsequent SRM, and can you provide it to us? Chris, I'd like you to keep track of that for us. I don't know the answer.

MS. RAY: I have done a little bit of digging. I have not looked at every SRM past -- all of the SRMs since '91. I think these issues, there was a number of issues on the evolution of plant designs. SECY 91-078 covered at least some of the electrical ones. I know --

MEMBER BLEY: But this particular SRM --

MS. RAY: Not that I have found.

MEMBER BLEY: -- said the commission's going to continue to look and will issue a subsequent SRM. All this SRM says, it's fine to issue this as a draft for now. Roy's eloquent statement led me to

believe the commission had come down very hard in support of this, and I'm looking for that. That's all.

MEMBER STETKAR: And the SER, whenever you finally get to the paragraph that says, "This is an open item," the SER refers to the SRM SECY 91-078.

MS. RAY: Right, I --

MEMBER STETKAR: If it's that document that Dennis just cited, that's --

MEMBER BLEY: That's all I'm asking.

(Simultaneous speaking.)

MEMBER BLEY: Is the one dated April 1st the --

MS. RAY: From what I have looked at, yes.

MEMBER BLEY: -- one you're referring to, or --

MS. RAY: That is the one.

MEMBER BLEY: -- is there another?

MS. RAY: We will double check, but from what I recollect, there is not another, but I will double check.

MEMBER BLEY: Thank you. Read it. It's informative.

MS. RAY: I understand. I was also --

that's why I did some additional checking on the later ones.

MEMBER BLEY: Thank you.

MEMBER SKILLMAN: I would like to ask a question, please. On your safety evaluation, Page 8-53, you have asked the question of the applicant, "What is the classification of the cathodic protection system?" This question has been, if you will, deferred to a COL item. What is the safety classification that you desire for cathodic protection to protect Class 1E equipment?

MS. SOM: We were looking for whether there is Class 1E system that needs Class 1E power. That's all we needed to know.

MEMBER SKILLMAN: If you find that there is?

MS. SOM: They said that they have -- I don't know.

MEMBER SKILLMAN: I don't know either, based on the --

(Simultaneous speaking.)

MS. SOM: -- they don't have, probably, and we can ask that question to the applicant. But it's a possibility that they may have the cathodic

protection not necessarily for carbon steel piping or tank or something. They may have something for the HGP that we don't need anything. I did not dig deeper on the cathodic protection.

MEMBER SKILLMAN: I would like to suggest that you do dig a little deeper. It seems to me that the cathodic protection system is generally forgotten in the rush of all of the big and important and sophisticated equipment when, in reality, the system, if it's functioning properly from day, really resolves a lot of problems. It's almost a forgotten art, but it's an important piece of the plant.

MS. SOM: I agree to that. That's why we asked that question, but it is not part of any standard review plan, as of now.

MEMBER SKILLMAN: Well, gee whiz, does it need to be?

MS. SOM: It needs to be when SRP is revised. Then both cathodic protection and the heat tracing should be there. But as of now, we questioned, and applicant answered the question.

MEMBER SKILLMAN: All right, thank you.

MS. SOM: Do you want me to dig deeper on that one?

MEMBER SKILLMAN: Yes, please. Thank you.

CHAIR BALLINGER: Other questions? Okay, we're going to have to make a little bit of a change, in that we have initially identified this time for public comments, under the assumption that the responses to some of the questions that we had from previous times involved proprietary information. Chris has checked this out and none of those responses involve proprietary information. Being that it's 4:00, we're in good shape. We'll switch and take up those questions now, if we can, and then take public comments at the end.

(Simultaneous speaking.)

MR. SISK: Excuse me one minute. Dr. Ballinger, we're ready to go. Let me, if I may -- this is Rob Sisk, again.

CHAIR BALLINGER: We might as well fire away.

MR. SISK: Okay, everybody has a copy, hopefully. We'd like to thank the subcommittee for the opportunity to kind of get back -- the purpose here is as we continue to proceed through these review meetings, we appreciate the questions and comments from the committee and wanted to take an opportunity

to provide back some responses to the questions that had been raised at the previous meetings.

I want to caution that what we're trying to do is be responsive to the questions. We do not have all of the experts back to dig into significant level of detail. Certainly, if there are questions that remain with the subcommittee, let us know.

We'll either be able to address them today, or we'll take them back and we'll continue, but we didn't want to have these just pile up at the end, recognizing that as you do subsequent chapters, some of these responses may be helpful. You'll see at the table, today, I have invited some of our local SMEs to present and discuss the RAI responses. I'll let each of them introduce themselves at the time. I'm looking at the clock. I think we have about an hour.

PARTICIPANT: That's about right.

MR. SISK: We don't necessarily need to go through each and every question, but we did want to make sure we flipped through each of these and gave the staff an opportunity to comment. We can either flip through individually, or we can go through and present until the committee feels they want to move in a different direction. Is there a preferred mode of

operation that the subcommittee would like to see?

CHAIR BALLINGER: I think we just start.

MR. SISK: With that in mind, then, we will just start. Our first chapter was Chapter 2.

MR. HUR: Let me introduce myself.

MR. SISK: Please.

MR. HUR: Sorry. My name is Seokhwan Hur from KEPCO-ENC. There are questions for four chapters, but I am going to explain the response for Chapter 2 and 10, and Chapter 5 will be explained by Tae Han, next to me. The Chapter 11 responses will be explained by Hyeok Jeong. Because of the time limitation, rather than reading out all the responses, I'm going to make it short. In the Chapter 2, there's a concern about the terms exclusion area boundary and site boundary because those terms are used interchangeably in the DCD. In our DCD, we use the exclusion area and the site boundary at the same meaning because we have used the term in the Korean, same ranging, same boundary, so we have used the term interchangeably. Question 2, there's concerns about the design basis flood level and maximum ground water level, one feet and two feet.

The concern was that if TG building was

below these level and how could the COL applicant know? There's the explanation about these concerns, probably its quite, can state for itself. Actually, the one building is included as one of the safety important SSCs. The water level for those buildings addressed in the DCD Tier 2 Table 2.01-1, so it should be designed with that water level. There is a term we have used in Section 2.4.4.2, artificially large floods.

There was concern about the meaning of the artificial large flood. Here is the explanation about their point. It's kind of simple, so I'm going to skip it. There is concern about low water, downstream dam impoundment of cooling water dikes, and those are not addressed. Downstream water control structures addressed in the DCD Tier 2 Subsection 2.4.4. There is a COL 2.4(1). The COL applicant provides site-specific hydrologic information addressed in DCD 2.4. There is a requirement of minimum safety-related cooling water flow in low water consideration. Those are addressed in 2.4.11.5. Any potential failures, such as downstream dam, impoundment of cooling water dikes, etc., should meet the requirements. The plant should be designed to fit low level B- low water

conditions. There is concerns about the ground water chemistry.

The point of the degradation, below-grade concrete degradation, for this issue, there is no ground water chemistry limitation in the DCD revision, but it has been added in the DCD through the RAI responses, so there is added in the DCD. The RAI 227-8274, Question No. 03.08.04-9. There is a simple and straightforward concern about the label, so the Figure 2.0-1 and 2.0-2 doesn't have the appropriate labels.

We're going to add the label in the associated picture. There is a question about the DC scope and out of scope of work in terms of the seismic design. The seismic design, the design certification scope is limited to the reactor containment building and auxiliary building and EDG and DFOT building, as are required in the DCD Figure 1.2-1. There is not any currently general DCD. There is actually -- there's a note identifying this configuration added through RAI responses. Probably, you can see the appropriate description in the RAI Response 8299, Question 03.07.02-15. There was concern about the re-entry building settlement between the nuclear island

common basement and EDG and DFOT building. Of course there is quite bigger than the .5 settlement in other adjacent buildings, but of course there is only electrical cable connections running between two structures, so usually, the electrical cable have enough flexibility to accommodate the 3-inch settlement.

MR. SISK: I just wanted to pause for a second. This is the Chapter 2 -- questions from Chapter 2 that we were asking -- these were questions that were raised during the Chapter 2 review, and we've provided a response. We recognize going through them fairly quickly. The committee may be reviewing them, but I wanted to pause before we go to Chapter 5. Questions clear? Answers clear? Should we move on to Chapter 5?

MEMBER STETKAR: Rob, to preclude any misconceptions here, No. 1, the questions are only individual members' questions. No. 2, silence in a subcommittee meeting does not necessarily mean agreement with anything. Quite honestly, it takes quite a while to review a question and review answers. I don't think any of us are capable of doing that in real time, especially questions that were asked a

couple of months ago. Please, for the record, do not interpret silence as tacit acceptance of any of these answers.

MR. SISK: Thank you for that clarification, John. I'm going to go a little further. As we indicate, this is the subcommittee discussion. The purpose was to put the information on the record, so that it was available to you for your consideration.

MEMBER STETKAR: Quite honestly, what's worked best in the past is if the applicant sends, through Chris, written responses to the subcommittee. They don't have to be tonns of information, but so that it allows us some time to go back and think about the questions and see what you're doing, rather than kind of just hitting us with this in real time.

MR. SISK: Thank you for that. We can certainly do that. My understanding was the questions were provided previously, Jeff.

MR. CIOCCO: I guess I don't understand. These were understanding questions from the last subcommittee meetings. Are you asking that things be submitted -- I guess I'm not following where --

MR. SISK: There isn't B-

(Simultaneous speaking.)

MR. CIOCCO: -- providing this on the record for your consideration for the subcommittees.

MEMBER STETKAR: Providing it on the record is fine, if you want to do that. I'm just concerned that anything that you hear or don't hear -- more importantly, what you don't hear in this meeting -- is interpreted as acceptance of the adequacy of what's on these slides as answering our concerns because we've not -- I don't think any of us have had a chance to really digest this information and look back at our individual questions. I know I certainly haven't.

MR. SISK: Appreciate that. I was just concerned -- I thought this was provided at the same time the Chapter 8 information was being provided to ACRS, but if that's not the case --

PARTICIPANT: I think this was provided day before yesterday.

(Simultaneous speaking.)

MEMBER REMPE: We just got the slides with the other slides. We didn't receive any written information. Furthermore, again, my notes may not be -- I went back and looked at my slide notes that I had

at the meeting. I'll be the first to admit my notes are not comprehensive. One needs to go back to the transcript. My notes indicated there was a lot of discussion about what in your design limits the wet bulb temperature. I don't see any question and response on that. Perhaps that was a discussion and that question wasn't fully answered, but I need to go back and check the transcript. That's an item that I would want to see some additional information on.

MR. SISK: Recognize we are not representing this as being all of the questions and answers that were raised during the time. We recognize that a lot of questions and answers come up. Some will be -- we can respond to, will respond to. Others, the staff may be responding to or addressing. Some of them --

MEMBER BLEY: Rob, let me interject because I want to make sure we don't have a misunderstanding. I think all John was saying is we appreciate getting this information, but don't expect that we'll completely comprehend it today. You might hear about this in the future. We're not asking for some formal submittals or anything like that, absolutely not.

MEMBER STETKAR: As a matter of fact, I know it takes quite a bit of effort to put together slide packages and have people here to present those slides. That might be even more effort than you want to dedicate to getting the feedback to us in the future. It does take quite a bit of effort to put this together and bring people to present it.

MR. SISK: We want to make sure we have the proper responses and complete responses provided. We're not doing this off the cuff, if you will.

MEMBER STETKAR: No, that's -- as I said, that's --

MR. SISK: I appreciate --

MEMBER STETKAR: There might be a better way -- all we're saying is there might be a better way of transmitting the information back to us without having a formal presentation.

MR. SISK: I think the question really revolves around is there a better way that allows us to get it on the record? I don't know the answer to that.

MR. CIOCCO: I guess we're asking you what do you want?

MEMBER BLEY: This is just speaking kind

of in general, because I'm the chairman of the committee, for the staff, I don't want to put an impression out there we're looking for real formal things coming in. If you're happy with this way to do it, I think we're getting the information. The only caveat is it might come back again after we think about it.

MR. SISK: We'll take that under advisement. We're not expecting a conclusion today. The purpose of today was to present the information, so that you have more information as you go forward with subsequent chapter reviews.

MEMBER REMPE: I'm puzzled by your response, though. There are additional questions that you believe that we will hear from your organization, responses back to Chapter 2. Is this what you think is the complete response that you'll be providing for questions raised on Chapter 2? When I asked you what about wet voltage, you said there may be some other issues raised at that meeting we haven't -- this isn't a complete response for Chapter 2 questions. When will we know B-

(Simultaneous speaking.)

MR. SISK: As we've gone back earlier, we

are not taking -- the position has not been that we are going to respond to every question in detail with analysis or work, what have you. The questions are being raised in this subcommittee. Those questions which we can answer readily, without expending significant level of effort, we're going to do that. We're going to be responsive to the subcommittee. If there are significant concerns that the subcommittee feels needs to be addressed, I am assuming -- and if I'm wrong, please correct me -- that they'll be formally communicated to the NRC, and the NRC will either address those or communicate back to us. But I think the process was to simply provide some feedback.

MEMBER REMPE: Could I rephrase what you're saying? Basically, this is all of the Chapter 2 questions that you plan to provide feedback for until we write a letter with our concerns or something, or is there more that we should be waiting for on Chapter 2?

MR. SISK: This is what we're planning on providing back with regard to Chapter 2.

MEMBER REMPE: Okay, that's what I'd like to --

MR. SISK: We're not saying they're all

the answers. This is what we're planning to provide to be responsive to subcommittee questions -- something you want to hear, there's a process for that.

CHAIR BALLINGER: You probably know by now that we're a fairly uncontrollable bunch, so we can ask questions at any time, and we do, so proceed.

MR. SISK: With that being said, and with the caveats as listed, I'm going to go ahead to Chapter 5.

MR. KIM: Good afternoon. My name is Tae Hak Kim from KEPCO-ENC, staying in Vienna office in KHNP. Response to Chapter 5 questions. Question 1 is confirmation of Section 3.9.1 addresses the transient of 60-year design life. APR1400 design basis initiating events and frequencies of ASME Code Class 1 and Code Class classical structure component of the primary system are shown in DCD Table 3.9-1.

MEMBER SKILLMAN: I am the one who asked this question. If this were to be the answer that you provide, I would push back very strongly because you've got four reactor coolant pumps. Your tech specs allow one and two-pump operation for a limited time period. If you're a four-pump operation, full

power, and for whatever reason, you drop two pumps in one LOOP, the downcomer is pressurized by the remaining two pumps in the alternate loop. The pump in the loop that has just become idle will flow backwards, and you will experience a temperature transient, a fairly large one, on the reactor coolant pumps. Your anti-rotation devices will lock, and you'll flow backward through that steam generator. I came from a B & W background, where we analyzed this very carefully because we knew we could run one, two, three, or four pumps, so we knew we could have backwards flow.

Because of the way your tech specs are written, you also can have, at least for a limited time period, one or two-pump operation in Mode 1. That was the question I was asking. I just went through your 3.1. The question that I asked is not answered. I think that's what Dr. Rempe was trying to point to. Are these just general reactions to our questions, or did you really understand what it is that we were trying to probe when we asked our question?

MR. SISK: We're trying to understand, make sure that we're answering. That's why we wanted

to take a moment today. Are we missing something, is there a disconnect. Let me ask our understanding of the question, confirm Section 391 addresses the number of transients that are included in the 60-year design life consideration.

MEMBER SKILLMAN: For reverse flow.

MR. SISK: Including reverse flow.

MEMBER SKILLMAN: Not including, for reverse flow.

MR. SISK: Right, but there are other -- yes. The APR1400 design initiating event frequencies, the number of transients, including reverse flow, used in the stress analysis are shown to be in Table 3.9-1. The answer to that question should be --

PARTICIPANT: Yes.

MR. SISK: In Table 3.9-1, it identifies that the reverse flow has been --

PARTICIPANT: Identified here.

MR. SISK: -- identified, and the number of reverse flows are identified in Table 3.9-1.

MEMBER SKILLMAN: I don't see that table, but I would like to see that.

MR. KIM: The frequency include reverse flow.

MEMBER SKILLMAN: If it's there and I've missed it.

MR. SISK: That's why we're --

MEMBER SKILLMAN: If it's not there, include it.

MR. SISK: That goes to Mr. Stetkar -- if you're not satisfied, when you go back to look to see if it's there --

MEMBER SKILLMAN: I'm looking.

MR. SISK: I don't have it right in front of me. I'm sorry.

MEMBER SKILLMAN: I'm looking for it. Thank you.

MR. SISK: Thank you.

MR. KIM: Question 2, sizing basis of reactor vent head vent. Reactor coolant gas vent sizing is derived from the natural circulation analysis that credits the RCS depressurization using RCGV function. Also, our RCGV sizing is sufficient to meet EPRI URD requirement that the rest one is EPRI URD requirement description. Also, there's the concern of loops seals.

Loss of loop seal is not considered because there is no loop seal in RCGVS line. The

concern of Question 3 is configuration of three-way valve, what prevents internal blocking? As shown in figures, this valve is designed just to change the flow direction, only. Therefore, there is always open condition under the seat or over the seat, so we don't think any possibility to block. Question 4, POSRV spring is made of Alloy 750. What heat treatment is done? Actually, we got this information from vendor from reference plant. The POSRV spring material of single weight three and four, which is the reference plant of APR1400, is not Alloy 750. The material of reference plant of main valve spring and spring loaded pilot valve spring is like this. Also, we did not specify any heat treatment in this. Question 5, LTOP over-pressure release and staff RAI on energy input.

CHAIR BALLINGER: Back to the previous one, I'm assuming that the DCD will get corrected? It says X750 in the DCD.

MR. KIM: No, we don't specify any material.

CHAIR BALLINGER: Okay.

MR. KIM: Question 5, LTOP over-pressure release. Actually, this item is raised by the big difference of temperature. Is there any realistic

temperature difference? Yes, it's a very conservative assumption, the assumption of 250 Fahrenheit degree is much more than our operating procedure expected, maximum 100 Fahrenheit degrees. The description of this assumption is described. We assumed the RCS 350 and RCS cooldown to 120, but the secondary side stayed in 350 Fahrenheit, so there's going to be 230 Fahrenheit difference. With a margin of 20, we assumed 250 Fahrenheit for conservative -- yes, we know it's a very conservative assumption. Question 6, what ensures APR1400 reactor vessel rings do not suffer the Belgium plant forging issues? This is the kind of a factory procedure I got. Vacuum degassing methods are used for manufacturing of APR1400 reactor vessel ring forging for hydrogen removal.

Such methods include ladle refining and ladle-to-ingot mode mold vacuum degassing. Ladle refining furnace is equipped with bottom plugs for argon gas bubbling, together with induction stirring system and a vacuum cover. This system is to stir molten steel, and thus promoting the removal of hydrogen. In ladle-to-mold degassing process, the molten steel is poured from the pony ladle into the ingot mold, placed in a vacuum chamber. Also, the

finished product will then be subjected with ultrasonic test inspection, per ASME code.

MEMBER REMPE: In this case, is that information somewhere in the DCD? How do you incorporate this level of detail into the actual DCD, if that's how you ensure this?

MR. KIM: Actually, this is not described in DCD. This come from the information after ACRS questions.

MEMBER REMPE: So you're planning, though, in the future, to incorporate this information? This is a process on how you want to have this fabrication done, in order to ensure that you have the appropriate product. How does this -- if someone wants to go forward and build this plant in the U.S., how do they know to follow that process?

MR. SISK: I don't think we're going to be putting, again, in the DCD, detailed manufacturing process requirements. Those would be identified in procurement specs, and they will be identified by the use of proper vendors and procurement. That will be one of the things the COL applicants will be addressing in procuring the design. I don't think the intent, at this time, was to put in a specific

operating experience, a manufacturing requirement in the DCD.

MEMBER REMPE: Okay.

MR. KIM: Thank you. Question 7, regarding the surveillance capsule removal schedule, 217 degree and 224 degree location are very close. Why not move symmetrically? The surveillance capsule with the highest lead value will be removed for the first time. After the first removal, higher lead factor capsule with be removed earlier. Also, the capsule of EOL removal is also planned with another highest lead factor for predicting a longer period of time. The last sentence is the definition of lead factor from ASTM. Question 8, RCP cooling. With no CCW and seal injection available, how long operator have to trip the pump before bearing damage or seal damage, pump vibration happen? This is kind of proprietary information. This is just a summary of tests.

MEMBER STETKAR: Is this proprietary? Because you have to be really careful --

MR. KIM: No, not this one.

MEMBER STETKAR: Be careful. This is on a public record, both the slides and what you say.

MR. KIM: Whole test is proprietary. I just summarized, though.

PARTICIPANT: It's not proprietary?

MEMBER STETKAR: It does, but he said -- he started to say this is kind of proprietary. I wanted to make sure that he wasn't going to say something on the record that is.

MR. KIM: Actually, this is not proprietary. The test was run as part of a 50-hour performance test. Thirty minutes after loss of CCW, bearing pad temperature was measured, and the bearing pad temperature did not reach to a level of deformation. After the test, bearings were inspected and found to be in good condition, no damage to the pad, with only normal wear marks. Vibration levels were acceptable throughout the loss of CCW test.

This is the basis of 30-minute continued operation of loss of CCW for our design. Question 9 and 10 kind of similar question for fluid instability and some wear. San Onofre's steam generator were built to same specifications, but two units had different experience relative to excessive wear.

How APR1400 confirming it won't happen? In case of APR1400 steam generator, to prevent upper

horizontal tubes from fretting wear, two kinds of design improvements are applied, an aggregate flow distribution plate is added to reduce the high flow velocity in the central cavity of tube bundle, and the vertical tube supports are added to restrict the displacement of upper horizontal tube.

Also, the ATHOS computer program has been used for the design of all the OPR1000, as well as APR1400 steam generator in Korea domestic over 20 years. Question 10, what gives confidence that fluid elastic instability seen at San Onofre is not seen at APR1400? The excessive tube wear at the SONGS RSG was very unusual phenomenon because it was induced by the in-plane fluid elastic instability, instead of out of plane. APR1400 steam generator will not have such in-plane fluid elastic instability, based on two aspects, one design feature and operating experience.

Also, the thermal hydraulic analysis of steam generator secondary side is input to the FEI evaluation. Also, as mentioned, ATHOS computer program has been used for this analysis for input. This description of design and operating description. I want to move into next slide. In addition to the above design features and operating experience, the

recent FEI experiment, just for information, provide further justification on the soundness of our APR1400 steam generator against in-plane FEI phenomenon.

SONGS RSG uses the triangular array, but the APR1400 uses square array. For the square array, it is concluded that no instability is observed in the in-flow direction. Question 11, is there a manual valve at the suction of containment spray pump, otherwise one has to close Valve 347 at the IRWST suction to replace SCS pump. Yes, CS pump suction from the IRWST should be closed to perform the shutdown cooling function using shutdown containment spray pump. The Valve 347 should be closed because there is no manual valve in the CS pump suction side. Question 12, any valve do not fail as-is. Response, all valves in SCS are fail-as-is. Question 13, need drawing that shows every line connection TI IRWST and the location of spargers.

I know why you ask this question because we have a lot of information in various places, but we cannot find in one figure showing every connection and every detail, so this is the related information contained for IRWST connection, so various figures will be referenced. Also, this shows the associated

figure list for IRWST connection and Plan B.

Question 14, on reactor coolant gas vent system, certain valve configurations could prevent pressurizer venting. Do valves involved in venting have control room position indication? The solenoid operated reactor coolant gas vent valves are provided in the reactor coolant gas vent system. Open/closed positions are indicated in the MCR and RSR.

A manual pressurizer steam isolation valve is provided in the RCGVS and does not provide the position indication in the MCR and RSR. The valve is locked open and is controlled by the administrative procedure, by surveillance requirement, things like that. Question 15, need AAC generator for 16 hours to operate RCGVS, but cannot operate beyond 16 hours. Does the Level 2 PRAs? In APR1400 Level 2 PRA, the RCGVS is not modeled as a severe accident mitigation feature which needs to be operated during the severe accident. The RCS depressurization by operating the reactor gas vent flow paths during a severe accident is not considered in the APR1400 Level 2 PRA model.

Hence, even if the RCGVS is unavailable beyond the 16 hours, in case of SBO accident, it does not impact on the APR1400 Level 2 PRAs. Question 16,

intersystem LOCA aux pressurizer spray line not included. The scope of IS LOCA evaluation is the low-pressure system connected to the RCS. The auxiliary spray line is a branch off the charging line downstream of the regenerative heat exchanger and designed to pressure greater than or equal to the RCS design pressure.

Auxiliary spray line is not included in the scope of IS LOCA evaluation. Question 17, each MSSV rated capacity appear to be 5.3 percent full power. Each POSRV can relieve 3.5 percent full power. For MSSV, 5.3 percent is a reasonable approximation. However, for POSRV, there is no such requirement for thermal power, so the POSRV capacity is set to prevent RCS over-pressurization during transient, without considering the thermal power, just the worst case of loss of load.

MEMBER STETKAR: This is one where I actually got ahead of you in the presentation. The reason I asked about the POSRV energy removal capacity was to essentially confirm success criteria in the PRA for feed and bleed cooling. Because the PRA says you need to open two of them. I wanted to see whether that is accurate, conservative, or optimistic.

Despite the fact that there's no design criterion for relief, it does have some opening size and can relieve some amount of energy. That's the reason I asked it. Despite the fact that -- this answer is not what I was looking for. I just wanted to find out whether, indeed, 32 percent was about right, if I opened those at full radiant system pressure, after a reactor trip.

MR. KIM: We sized them based on the worst case with many combinations of scenarios in the case of loss of load.

MEMBER STETKAR: You sized them and they have a size. Since I'm not a thermal hydraulics valve type person, I was trying to figure out whether I had guessed the right energy relief capacity from them, given the fact that they are sized and however they were sized.

(Simultaneous speaking.)

MEMBER STETKAR: I'm not challenging why they were sized what they're sized -- why they were sized for what they are. I just wanted to make sure that I had that information available, so that when I go look at the PRA, the success criterion makes sense back there.

MR. HUR: In Chapter 10, there are total ten slides for 11 questions. For Question 1, there were concerns about the valve for the function and details of the control system. For the detailed schematic drawings, those were provided by the vendor, so that's why we cannot provide the detailed drawings, but we can explain the function and the concept of the isolation.

Each main stream isolation valve actuator is designed to provide a fail-open mode upon loss of valve external motive power, example hydraulic fluid or electrical power. The main stream isolation valves are designed to close automatically to isolate the steam generator from the secondary side upon the receipt of MSIS related signal generated by any one of the following conditions. The MSIV actuator control system is designed to provide valve operation on two independent control channels. The details are provided by the MSIV vendor. In Question No. 2, there was a concern about the steam relief capacity of main steam automatic damp valve rate. That was addressed in Table 10.3.22-1. There is 1.1 million pounds per hour capacity, and the controllable capacity of 63,000 pounds per hour.

That's much less than the total relief capacity. There was concern about the intent of that. Actually the capacity of the 1.1 million pounds per hour is required for removing maximum decay heat after a reactor trip, and the capacity of 63,000 pounds per hour is the minimum controlling capacity to remove RCP heat during hot standby conditions.

MEMBER STETKAR: This is another one where I'm trying to stay ahead of you a little bit. I asked this question because I hung up on the notion of the controllable capacity was 63,000. This says, I think, that the minimum capacity that I need for removing reactor coolant pump heat is 63,000 pounds per hour, and the maximum relief capacity is 1 million pounds per hour. Can I control those valves all the way from fully closed to fully open, reliving 1 million pounds per hour? As an operator, can I manually control those valves over that full range?

MR. KIM: Actually, we need confirmation.

MEMBER STETKAR: That's the notion that I was hanging up on is --

PARTICIPANT: You're looking for the control from --

MEMBER STETKAR: Yes, as I read it, it

says here's the maximum capacity, and it has a controllable -- I've forgotten the words, but a controllable capacity of 63,000 pounds per hour. If I want to do a rapid cooldown for some reason, I might want to be able to control it at 500,000 pounds per hour or something like that.

MR. KIM: Between 63,000 --

MEMBER STETKAR: I'm trying to find out whether it can be controlled by some sort of active control, all the way from fully closed to fully opened.

MR. SISK: You're looking for the full range.

MEMBER STETKAR: The full control range on the valve, yes.

MR. HUR: Question 3, there is concern about emergency blowdown system and what is the emergency blowdown function and what is the criteria for opening the emergency blowdown line and criteria for resetting the steam generator blowdown isolation signals and the criteria for terminating the emergency blowdown?

The emergency blowdown system is actuated manually by an operator to reduce the water level by

opening the isolation valves in both blowdown paths. The blowdown control valves are automatically closed when the singular blowdown flash tank water level reaches the high level setpoint during normal operation. The isolation valves are maintained in the closed position. There are safety-related narrow and wide range water levels.

The wide range water level is used to initiate a reactor trip, and the auxiliary feedwater system at the low level setpoint, and the narrow range water level is used to initiate a reactor trip and the main steam isolation signal at the high water level. The low water level alarm comes from the wide range water level instrumentation, and the high water level alarm comes from the narrow range water level instrumentation. If a similar tube rupture occurs, high level alarm, reactor trip, and the main stream isolation will be generated by narrow range water level instrumentation. Question 4, there was a question about the pipe size from the aux feedwater storage tank to the aux feedwater pump suction. There was editorial errors.

Recently, the new RAI has been issued, so the data will be corrected through the RAI response.

Question 5, there was a question about the modulating valves powered by the Train A and B eight-hour battery. Turbine-driven aux feedwater train have two methods to control the steam generator water level. One is using the aux feedwater modulating valve that is powered by the A and B. The other one is controlling the level using the aux feedwater isolation valves.

Those are powered by the Trains C and D, with 16-hour batteries. The aux feedwater pump turbines are supplied by the power from Trains C and D. In case of station blackout, the modulation valves, which are fail open types, are opened, and the aux feedwater isolation valves are operated to control the steam generator level. Therefore, in case of the station blackout, the turbine driven auxiliary train can supply the water to steam generator by controlling the aux feedwater isolation valves. Question 6, have you done an analysis of missiles from turbine driven aux feedwater itself? The turbine driven aux water pump has an emergency trip system, mechanical and electrical trip system, to prevent the missile due to the turbine overspeed.

In Korea, the vendor of the turbine and

motor -- the safe pump will provide the missile analysis report to demonstrate the postulated missiles for rotating parts of equipment would not penetrate through its casing or housing at 120 percent overspeed condition. The aux feedwater pump is located in physically separated room. The common discharge line of the aux feedwater pump is connected inside the containment building, not in the aux feedwater pump room.

The common suction line of the aux feedwater pump is branched at the aux feedwater storage tank room. Therefore, there is no adverse effect of the aux feedwater system due to the missile of aux feedwater pump. Question No. 7, there was concern about the setpoint to close the aux feedwater isolation valve. The AFAS is set or reset according to the steam generator water level. When the steam generator water level reaches to the reset point, 40 percent to wide ranging, aux feedwater attribution signal is reset, and the aux feedwater isolation valves are automatically closed. Question 8, in the DCD Figure 10.4.9-1, there was a correction to the raw water makeup supply connection to the aux feedwater storage tank. There was concern about the raw water

used.

The aux feedwater system has two 100 percent capacity auxiliary feedwater storage tanks. The makeup water was supplied by the demineralized water storage tank. To increase the reliability, there is connections, as a backup system, to the auxiliary feedwater tank from the condensate storage tank and the raw water storage tank. There was a question about the capability -- volume of the raw water tank.

There is IBR TeR in the APR1400 that is addressing the Fukushima accident, and that has some volumes for the beyond design basis event. Question 9, there is a concern about the main steam isolation signal. In APR1400, the isolation signal isolates all the valves to the steam generator, so there is not a clear design, the ACRS thought that is not a clear design, so asked us to know what analysis was done to justify that decision. Main stream isolation signal is generated by high steam generator water level and low steam generator pressure and high containment pressure. Selective isolation of steam generator or selective valve isolation requires very complicated control logic design. APR1400 ESFAS

design prefers simplification of signal generation and ESF actuation logic.

Therefore, we used this design. On Question 10, the maximum flood height was determined to be 104 feet above grade level. There is a non-safety-related switchgear room at the elevation below grade in the turbine building, so there was concern about the flooding or watertight doors. In the switchgear room, the general access door is installed on the flood level, 104 feet, based on the KURD document.

There is no need to consider the water protection doors. For the battery rooms, those are not required to be protected from the flood because it's non-safety related. Question 11, there was Table 10.4.8-3 listing the codes and standards for the steam generator blowdown system. There was a question why it doesn't have the other systems. The answer is that the steam generator blowdown system conforms to the Reg Guide 1.143, Revision 2. It has the required codes and standards. We added the table for the associated systems, such as the liquid waste management system, gaseous management system, and solid waste management system to show the conformance

to the Reg Guide 1.143. For the other systems, the applicable code is listed in the DCD Tier 2 Table 3.2-1.

MR. JEONG: Good afternoon. Let me introduce myself. My name is Hyeok Jeong. I'm working for KEPCO-ENC and working at Vienna KHNP office now. I'd like to address the responses to ACRS Chapter 11 questions not responded during the previous meeting. There are 3 questions. Question No. 1, where is the space in the certified design compound building for laundry if I wanted to put in a laundry?

As you can see, the picture of 1.2-824, spaces for laundry are available in the compound building, elevation 63 feet. On this floor, there are detergent waste tank room, contaminated clothing storage room, and non-contaminated clothing storage room. The area of each contaminated clothing storage room and non-contaminated clothing storage room is about 792 square feet. These storage rooms can be used to install washing and drying machines if necessary. In Korean nuclear power plants, laundry are generally treated onsite. These rooms are used for this purpose. Two detergent waste tanks, 6,000 gallons each, are available to collect detergent

liquid waste for treatment and release. The capacity of each tank exceeds the requirement of ANS 55.6, Table 7.

This table is for daily maximum specified by daily maximum generation of laundry waste of 2,000 gallons. Second question was if I have a high radiation on a gaseous discharge and Valve No. 008 does not close, how do I stop the gaseous discharge? When do I open Valve 1015? When, during normal or abnormal operations would that valve be opened? I attached a picture on the next slide. It is taken from the GRS flow diagram, Picture No. 11.3-1.

Please see this picture to understand easily. The response is too long, so it is helpful to understand easily. Since the GRS is based on continuous operation, the isolation is not normally used. Gaseous effluents from the GRS is mixed with the GRS cubicle ventilation flow, and then filtered by normal exhaust ACU to the environment. In the event of high radiation with the Valve No. 008 not closed tight, the two valves -- you can find the valves both sides of the 008, No. 1013 and 14, located at both sides of the valve, to close for maintenance of Valve No. 008. Valve 1015 is opened for vent flow until the

Valve No. 008 is fixed. It is noted that the normal GRS cubicle exhaust is routed to the compound building ventilation system, and it's treated by the normal ventilation ACU, or diverted to the emergency exhaust in the condition of high radiation.

Radiation monitors located at GRS and HVAC system continue to detect the flow that contains radionuclides. In addition, the vendor for GRS package -- as you can see in the picture, left side -- is required to provide another isolation valve in the effluent discharge line. This isolation valve can be closed remotely when the isolation valve, Valve No. 008, fails to close.

Therefore, it is considered that the gaseous effluent to environment is monitored and controlled at all times during normal operations. Last question was do you have any operating experience to confirm the fact that you generate less than the amounts of spent resin that you are assuming in your design? We are assuming ten years. As you can see in the table, I got some plant operating experience data for eight units, for ten years. The spent resin long-term storage tank is sized for storage of up to ten years of spent resin. The table below shows the

operating experience of spent resin generation in Korean nuclear power plants for recent ten years. It also provides the volume ratio of filled spent resin to APR1400 spent resin long-term storage tank design capacity.

The spent resin is stored up to about 50 percent of spent resin long-term storage tank design capacity, considering the resin sluice water volume. Since the filled volume ratio in the table are much less than .5, it is confirmed that the spent resin long-term storage tank has sufficient capacity of spent resin storage for ten years.

MR. SISK: If there are additional questions, and taking Mr. Stetkar's comment, we recognize this is quick, but we did want to get something on record and look forward to future dialogues as we go forward, recognizing there were some comments and feedback already today that is helpful. But I think the message we want to leave is we're interested in the engagement. We're interested in the comments and the dialogue. We appreciate these, and we will continue to work, as we go forward, to complete the review of the DCD. Thank you.

CHAIR BALLINGER: Thank you. Questions

around the table? In the meantime, are we going to get -- is it open?

MR. BROWN: The bridge is open.

CHAIR BALLINGER: Any questions from the audience, such as it is? Hearing none, if somebody's out there, would you please let us know that you're there? Our vaunted audio/visual system is a little bit primitive. Unless you tell us you're there, we can't tell you're there.

PARTICIPANT: Just ask them for comments.

CHAIR BALLINGER: If you're there, are there any comments from anybody from the members of the public? We follow the same five-second rule. Hearing none, can we close the --

MEMBER BLEY: Automatic.

CHAIR BALLINGER: It's automatic?

MEMBER BLEY: It's automatic.

CHAIR BALLINGER: It's automatic. I guess we next go around the table to see if the members have any final comments. We'll start with Madam Joy.

MEMBER REMPE: My continual politically incorrect subcommittee chairman.

CHAIR BALLINGER: Madam is a term of endearment.

MEMBER STETKAR: Not today.

MEMBER REMPE: We're going to have to send you back to training. I don't have any questions about Chapter 8, but I guess, again, I participated in other DC reviews, but I think it would be helpful to understand what the process is here with getting additional feedback and how we plan to move forward, and then what is your plan for a letter? We usually have interim letters, and then we get them -- have, at the next subcommittee meeting, a follow up on we looked at your responses and we have additional questions. I'm a little confused on what the process is here.

CHAIR BALLINGER: I will clear up your confusion.

MEMBER REMPE: Please do, sir.

CHAIR BALLINGER: The plan is, currently, to write a letter in February, which covers Chapters 2, 5, 10, 11, and 8. That's what we will have done up to that point. That means that we have to accumulate whatever information we have on those chapters by that time, certainly by January or so. That would be the plan. The plan would be to write a letter on these chapters for February. If we look at the --

MEMBER REMPE: Will we have any additional subcommittee meetings before then, or we will just have a full committee meeting --

CHAIR BALLINGER: The full committee meeting in February.

(Simultaneous speaking.)

CHAIR BALLINGER: On the February full committee meeting, we have Chapter 4, but we won't have enough time to include Chapter 4.

MR. BROWN: We do have a December 14th meeting.

(Simultaneous speaking.)

MEMBER REMPE: -- be in the letter that is in February, or we are not sure yet?

MR. BROWN: It's not up to me.

MEMBER REMPE: In thinking about how John has emphasized jeepers, we just got these responses, I want to go back and look at the basis for these questions, should we plan that we will have a follow up -- there are some questions that have been identified for the staff -- or we'll just meet in February and we'll have the brief presentation on all of these chapters, and if there are questions that we had identified that didn't get answered, we'll bring

them up and put them in the letter? What's the plan here?

CHAIR BALLINGER: That's probably a plan.

MR. BROWN: I know that Maitri and Jeff and Ron and I, along with Matt, get together periodically. We're going to work through this process. But Maitri and I have built in follow-up days to address the questions. We may want to revisit, but we do have days on the schedule to address member questions. It may be too many questions, but it's up to --

MEMBER REMPE: But will there be any of those by the meeting in the February, or we'll just --

MR. BROWN: No.

MEMBER REMPE: -- identify outstanding questions in February and let the chips fall as they may?

MR. BROWN: That's what I think, but it's not up to me.

(Simultaneous speaking.)

CHAIR BALLINGER: We'll go with what we have.

MEMBER REMPE: Okay, just curious, so thanks.

MR. CIOCCO: If I could add something, Jeff Ciocco with the staff. We are planning, in the December 14th, to come back and give some responses to a few specific questions on Chapter 5. I'll just explain. We understand from the chair that any response to any outstanding question is voluntary on the staff's part. Of course, the fate of those questions lie in what you write in your interim letters. We are assessing your questions. Are they safety related? Are they compliance related?

Then we are generally going to do one of three things. We plan to come back and respond to a question in Phase 3, or we'll plan to respond to a question in Phase 5. We may go back and write an RAI based on a question that you have which came out of one of these subcommittees. We're going to write an RAI. You'll see it in the Phase 4 safety evaluation. Or we may not respond at all to one of your questions because we feel that we have good reasonable assurance to back our regulatory finding. Then we'll just kind of let the chips fall in that case.

MEMBER REMPE: Thank you.

CHAIR BALLINGER: Charlie.

MEMBER BROWN: No additional questions.

CHAIR BALLINGER: Walt.

MEMBER KIRCHNER: No additional questions at this point.

CHAIR BALLINGER: Jose.

MEMBER MARCH-LEUBA: No comment.

CHAIR BALLINGER: Mr. Stetkar.

MEMBER STETKAR: Nothing more, thank you. Thanks to KEPCO, and thanks to the staff. We covered a lot of ground.

CHAIR BALLINGER: Dennis.

MEMBER BLEY: You and Chris will have to work with the staff to decide what they're going to talk about at the full committee meeting. I would kind of hope that this open -- the contentious open item from Chapter 8 is part of what they talk about at that meeting, in case we want to write something about it in a letter, which we'll have to decide when we get to letter writing.

CHAIR BALLINGER: Matt.

CO-CHAIR SUNSERI: My thanks to the applicant and the staff, also. No additional questions.

CHAIR BALLINGER: Dana.

MEMBER POWERS: None.

CHAIR BALLINGER: Dick.

MEMBER SKILLMAN: Same as Matt and John, thank you to the staff and to the KHNP personnel. Thank you.

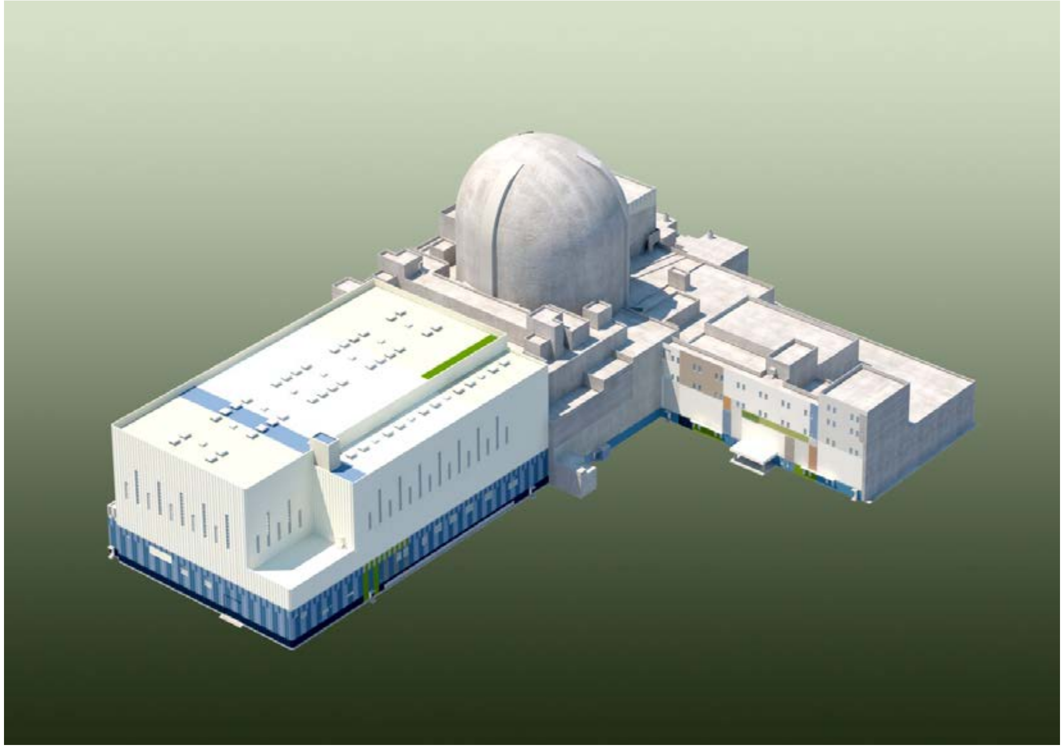
CHAIR BALLINGER: Harold?

MEMBER RAY: Nothing more.

CHAIR BALLINGER: Well, thank you very much. I think I would make a comment that the previous meeting that we had, the organization of the meeting was a little bit different than now, and I think this is a very significant improvement, this meeting, where we got a description of the systems which we asked for, and then stuck with the main things. I appreciate the effort that everybody's made to do that, also appreciate the effort that had been made to respond to these questions and things like that. Again, thank you very much. Unless there are any other comments, we are adjourned.

(Whereupon, the above-entitled meeting went off the record at 5:12 p.m.)

APR1400 DCA
Chapter 8: Electric Power System



KEPCO/KHNP

November 29, 2016

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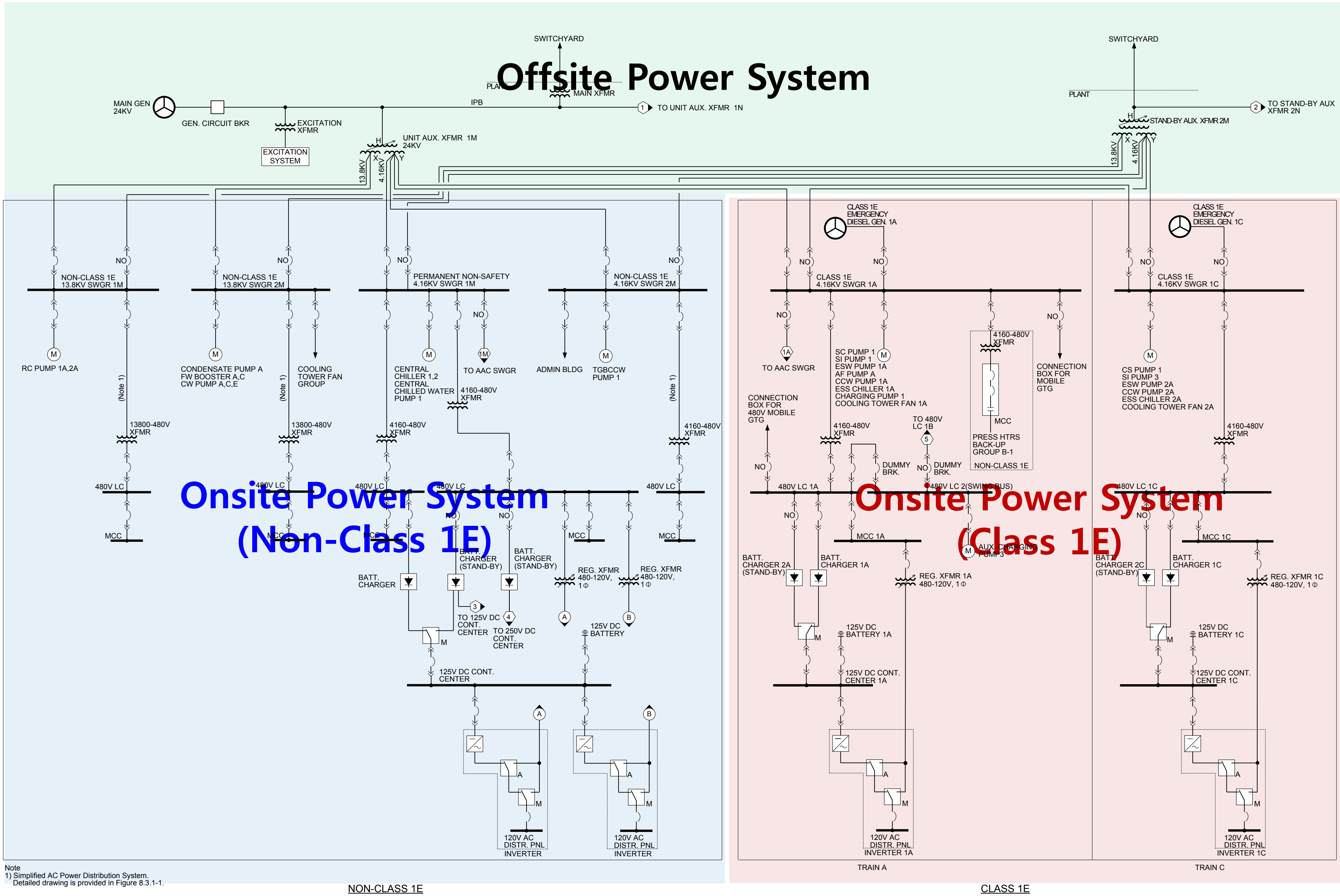
Overview of Chapter 8

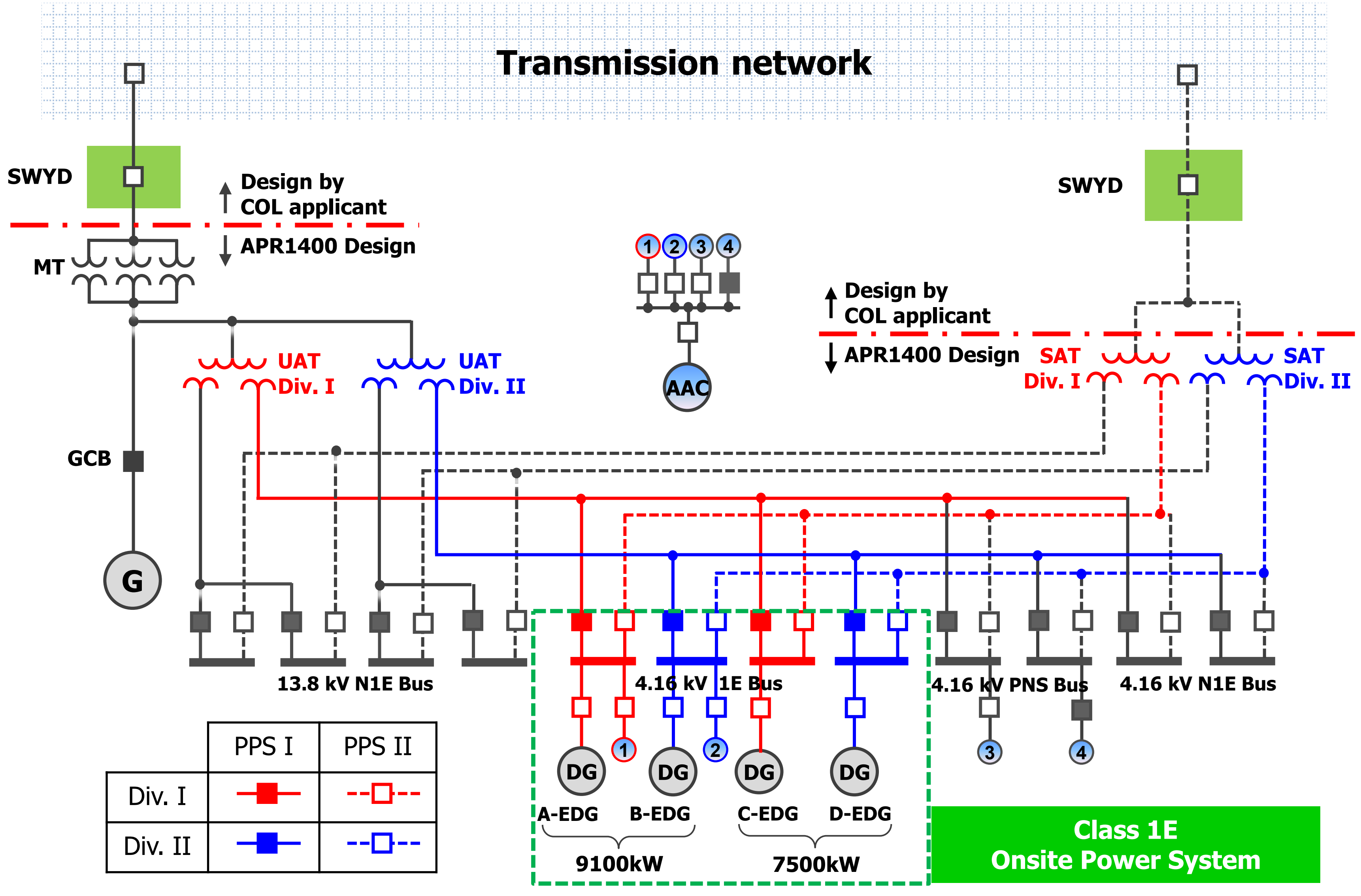
Section	Title	Major Contents	Presenter
8.1	Introduction	• Introduction to APR1400 electric power system (offsite power system and onsite power system) • Design bases	Kyung Woong KANG
8.2	Offsite Power System	• Design features of the offsite power system including transmission network, switchyard, offsite power system components and circuits, etc. • Conformance with 10CFR50 and NRC regulatory guides	Kyung Woong KANG
8.3	Onsite Power System	• Design features of the onsite Class 1E and non-Class 1E AC and DC power system including power distribution equipment, onsite power sources (D/G, batteries), etc. • Conformance with 10CFR50 and NRC regulatory guides	Kyung Woong KANG Seungdae KIM
8.4	Station Blackout (SBO)	• Descriptions on APR1400 strategies to cope with a Station Blackout (SBO) • Conformance with 10CFR50 and NRC regulatory guides	Seungdae KIM

NON-PROPRIETARY

8.1 Introduction



8.2 Offsite Power System



8.2 Offsite Power System

❖ Design Requirements – 10CFR50, Appendix A (GDC) 17

- Sufficient capacity and capability for all safety functions
- Two physically independent circuits
- Available in sufficient time following loss of all other ac power. One circuit shall be available within a few seconds following a loss-of-coolant accident (LOCA).

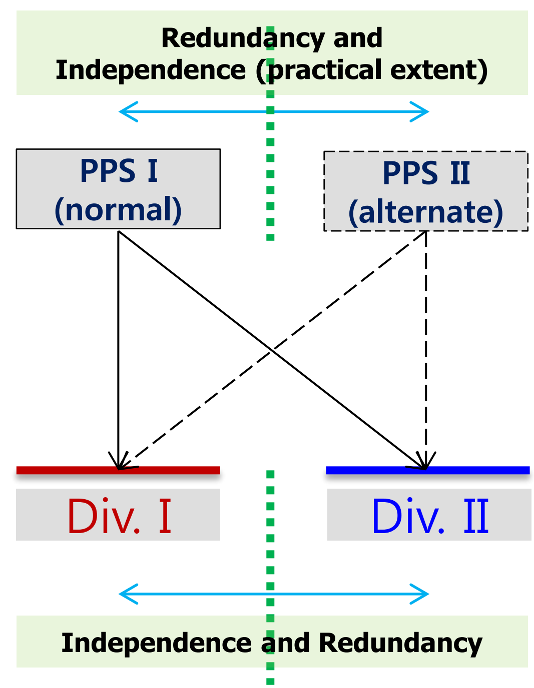
❖ Transmission Network and Switchyard

- Not in the scope of the APR1400 design.
- The transmission network should include **at least two physically independent circuits with sufficient capacity and capability** for the APR1400. The COL applicant is to identify and provide information on the transmission circuits (COL 8.2(1)).
- The plant switchyard design is site-specific and not within the scope of the APR1400 design. The COL applicant is to address the detailed design and required analyses including FMEA (COL 8.2(5),(6)).

8.2 Offsite Power System

❖ Offsite Power System Components and Circuits

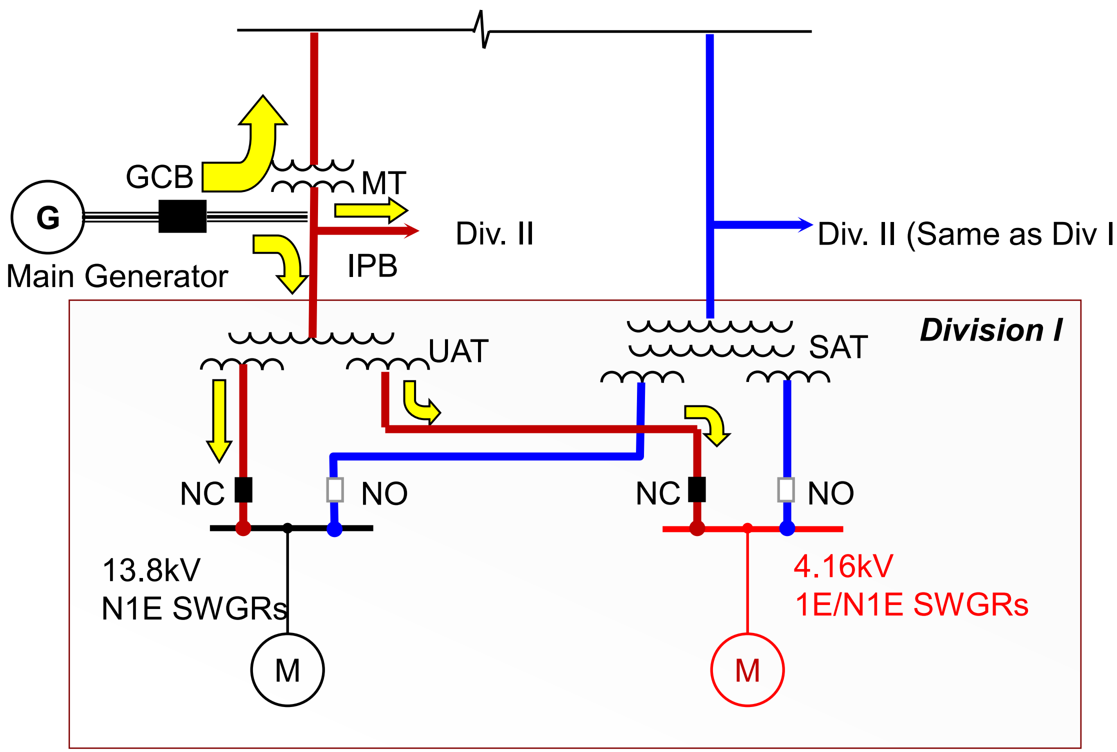
- Consists of main generator (MG), generator circuit breaker (GCB), isolated phase bus (IPB), main transformers (MT), two unit auxiliary transformers (UATs), two stand-by auxiliary transformers (SATs), and associated protection & control facilities.
- The offsite power system components and circuits are non-safety related (non-Class 1E) and boundaries between the offsite power system and onsite power system is the entry of incoming circuit breakers of the MV switchgears.
- Two offsite circuits are connected directly to each independent safety train (GDC 17; SECY-91-078).
- Two UATs (Div. I and II) and two SATs (Div. I and II), each sized to provide the required power for the worst case loading during normal, abnormal, and DBA conditions.



8.2 Offsite Power System

❖ Offsite Power System Components and Circuits (cont.)

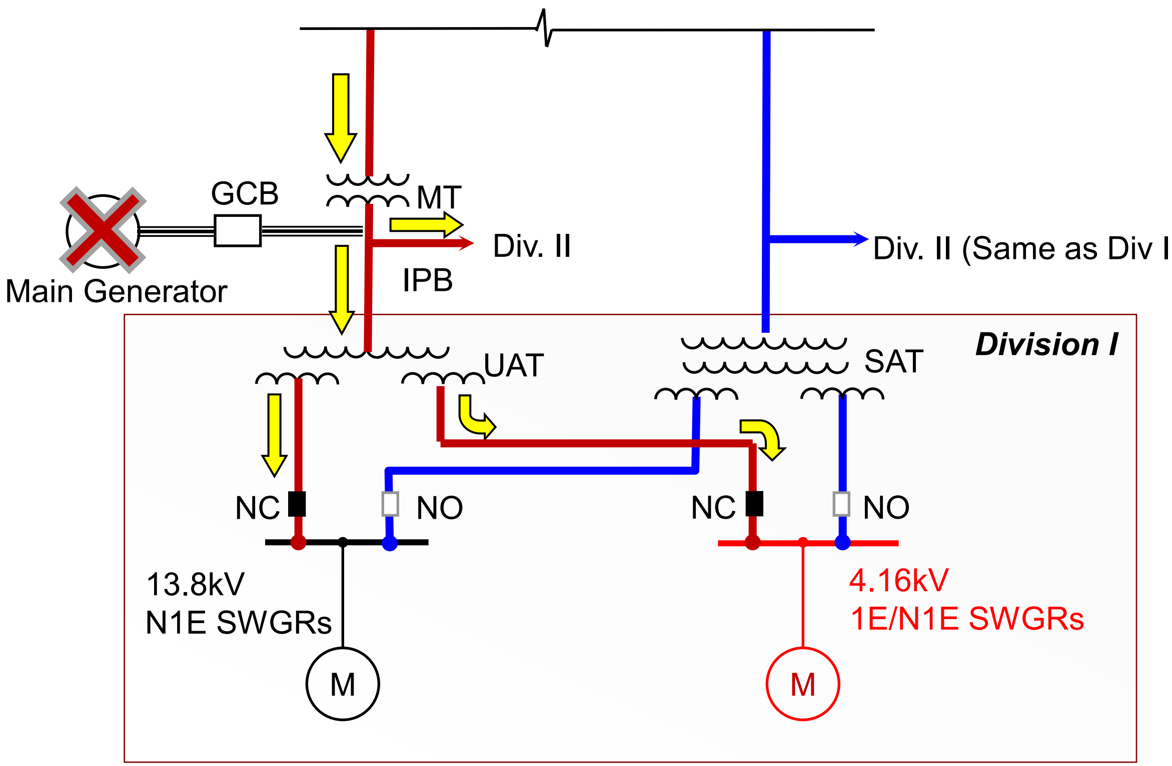
- During normal operation, the MG produces electric power and delivers the generated output to transmission system and also supplies the plant auxiliary loads.



8.2 Offsite Power System

❖ Offsite Power System Components and Circuits (cont.)

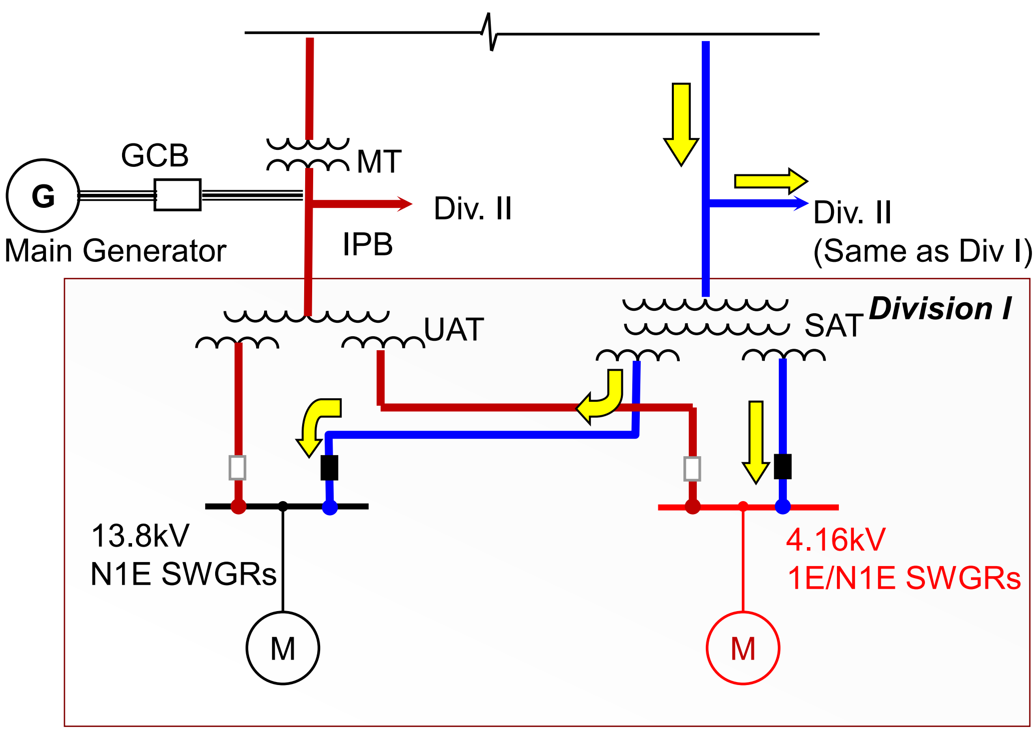
- In case the MG is failed or not in service, normal path of offsite power supply is secured by tripping/opening GCB (offsite power supply is available without interruption).



8.2 Offsite Power System

❖ Offsite Power System Components and Circuits (cont.)

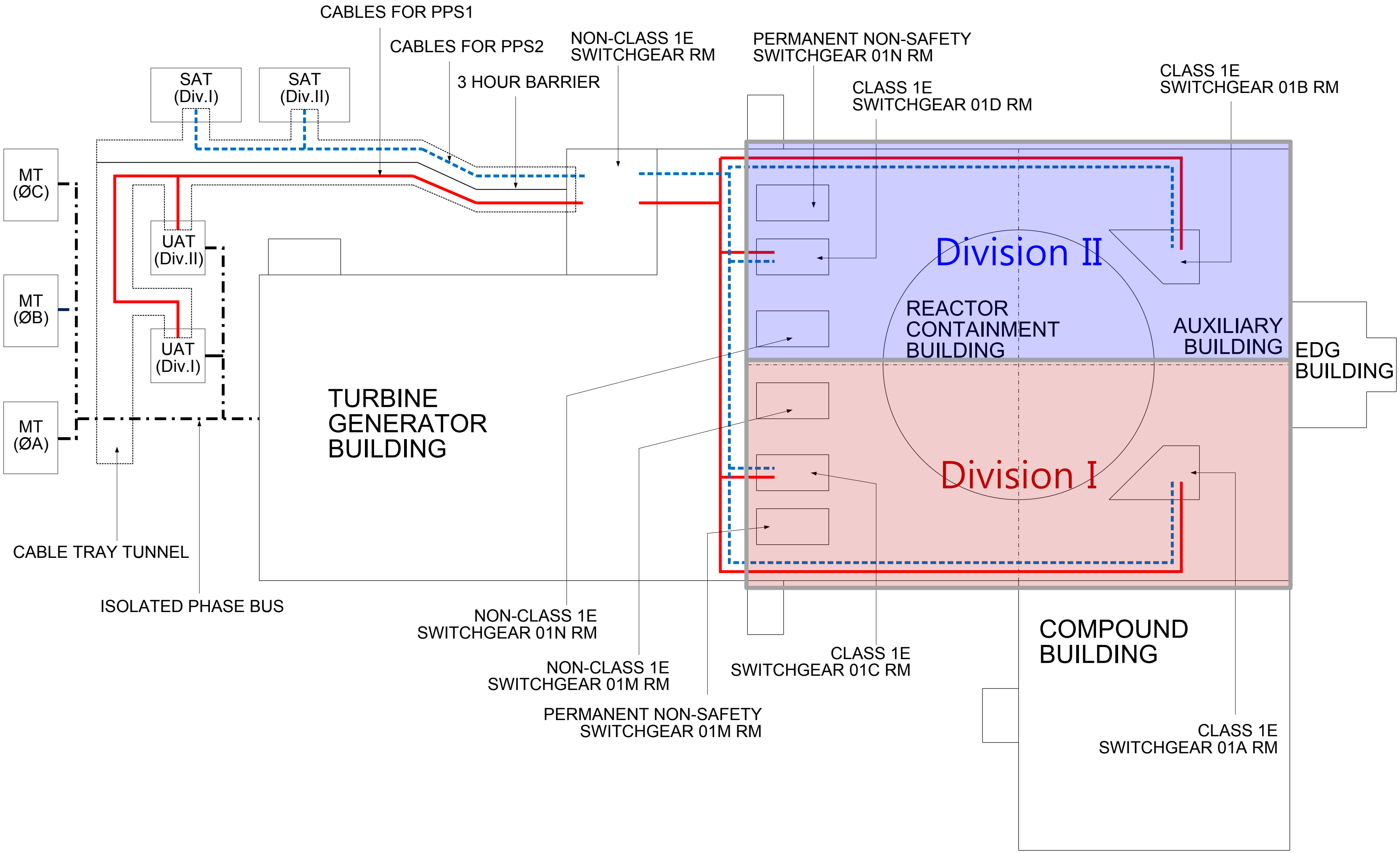
- In the event of a fault at normal offsite power circuit, offsite power supply to plant auxiliaries is switched to alternate path by **automatic bus transfer** (fast or residual voltage bus transfer); alternate path is available, normally, within 1 second.



- ✓ **Fast transfer**: automatic; within 100 ms; transfer permitted if the voltage and phase angle differences between the switchgear bus and alternate offsite power source not exceed the acceptable limits (per NEMA C50.41)
- ✓ **Residual voltage transfer**: automatic; back-up transfer to fast transfer.

8.2 Offsite Power System

❖ Separation between Normal and Alternate PPS's



8.2 Offsite Power System

❖ Open Phase Conditions (OPCs)

- Regulatory Requirements
  - ✓ BL 2012-01 "Design Vulnerability in Electrical System"
  - ✓ BTP 8-9 "Open Phase Conditions in Electric Power System"

- KHNP has performed a design vulnerability study including sufficient analyses needed to characterize and quantify the safety challenges of OPCs.

- To properly detect, alarm and mitigate against an OPC, a detection and protection system for OPC (so called OPD system) is being included on the primary side of power transformers (MT and SATs), in addition to the conventional protective relays in the APR1400, with the following design features at a minimum:
  - ✓ Detects an OPC over the full range of transformer loading;
  - ✓ Redundant detection subsystems with voting logic (e.g. 2oo2 or 2oo3);
  - ✓ Continuous monitoring and self-diagnostics (to MCR);
  - ✓ Meets separation requirements (IEEE Std. 384 as endorsed by RG 1.75).

8.2 Offsite Power System

❖ Open Phase Conditions (OPCs) (cont.)

- The COL applicant is to determine the specific type of OPD system to be used for the site (COL 8.2(7)) which meets the minimum requirements above and is applicable to the APR1400 design.

NB: OPC issue is currently being tracked as an open item (RAI 8521). Response to the RAI was submitted on November 14 , 2016.

8.3 Onsite Power System

❖ Design Requirements – 10CFR50, Appendix A (GDC) 17

- The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

❖ Onsite AC Power System – Class 1E (§ 8.3.1)

- Redundancy: two redundant load groups (Div. I and Div. II). Each load group consists of a divisional pair of trains: Train A plus C for Division I; Train B plus D for Div. II (GDC 17; RG 1.6).
- Single failure criterion (SFC):
  - ✓ The redundant equipment of the Class 1E onsite power system is located in separate rooms and different fire areas of seismic Category I building with adequate independence to assure performance of plant protection and safety functions assuming a single failure;
  - ✓ The Category I buildings are designed to withstand the effects of natural phenomena (GDC 2);
  - ✓ Designed to conform to SFC requirements per IEEE Std. 603 (RG 1.53).

8.3 Onsite Power System

❖ Onsite AC Power System – Class 1E (§ 8.3.1) (cont.)

- Independence (RGs 1.6 and 1.75):
  - ✓ Physical and electrical independence from the offsite power system and the non-Class 1E buses or loads (using isolation device, where required, per IEEE Std. 384)
  - ✓ Physical separation between equipment of redundant divisions including cables and raceways per IEEE Std. 384
  - ✓ No electrical connections or load share between Class 1E trains.
- Each Class 1E train (A, B, C, or D) has connections to both offsite power circuits (from UATs and SATs) and one connection to a Class 1E onsite power source (EDG).
- In addition, each Class 1E Train A and B has connection provisions to AAC source and mobile generator to address an SBO and BDBEE, respectively.

Bus	Train	Source	Phase	Remark
480V	A and B	Mobile DG (1,000 kW)	BDBEE Phase 2 (8 ~ 72 hr)	Mobile DG located in site area
4.16kV	A and B	AAC-GTG (9,700 kW)	SBO (0 ~ 16 hr)	
		Mobile DG (5,000kW)	BDBEE Phase 3 (72 hr ~)	Mobile DG mobilized from offsite

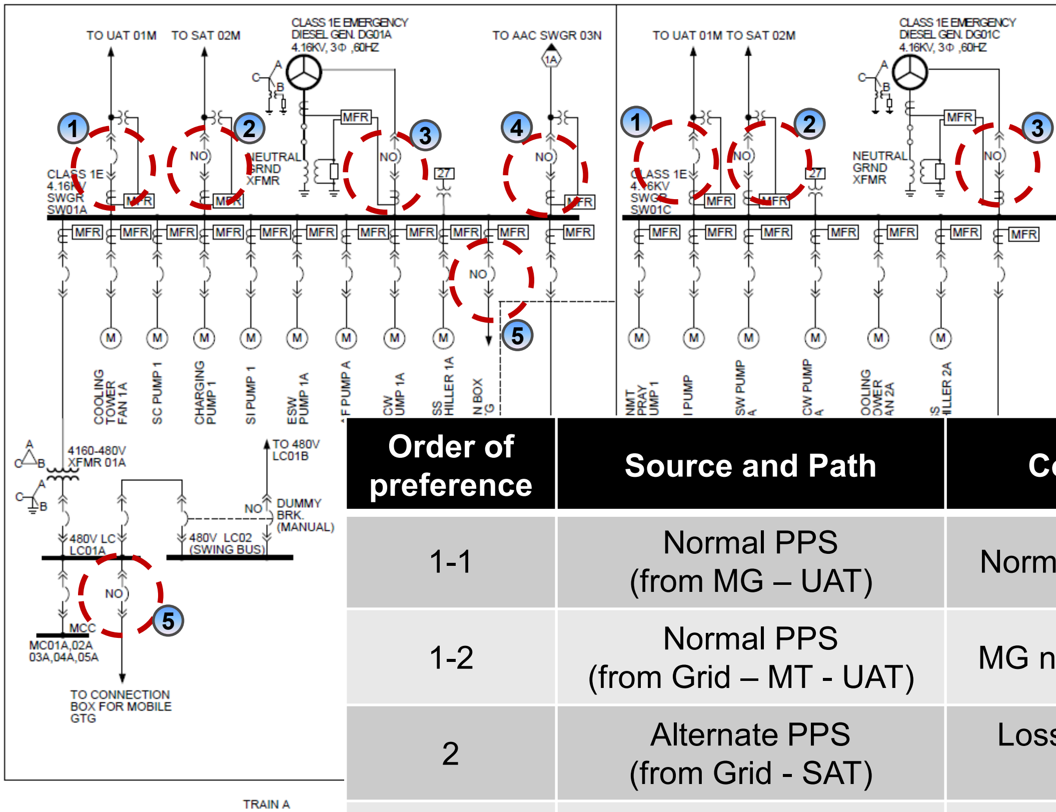
8.3 Onsite Power System

❖ Onsite AC Power System – Non-Class 1E (§ 8.3.1)

- Major components: 13.8 kV N-1E switchgears (2), 4.16 kV N-1E switchgears (2), 4.16 kV PNS switchgears (2), L/Cs, MCCs, and AAC-GTG.
- Consists of two divisions (Div. I and Div. II), which evenly share the plant non-safety loads.
  (NB: redundancy and independence requirements do not apply between non-Class 1E divisions)
- MV switchgears of each division have connections to both offsite power circuits (from UATs and SATs)
- When the offsite power from UATs is lost, the alternate offsite power from SATs is provided by an automatic bus transfer.
- In the event of a LOOP, the AAC GTG is manually aligned to two permanent non-safety (PNS) buses to supply essential non-safety loads (e.g. central chillers, T/G auxiliaries, non-C1E DC and IP loads; essential lighting.)

8.3 Onsite Power System

❖ Order of Preference - Onsite AC Power Supply for Safety Function

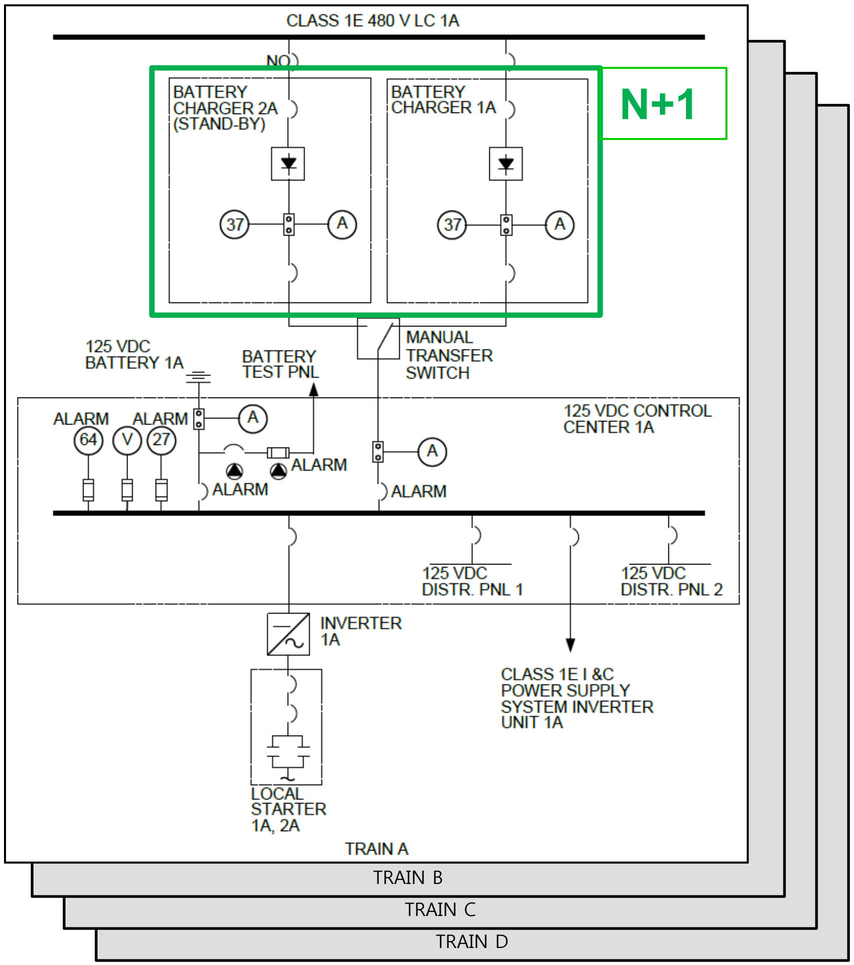


Order of preference	Source and Path	Condition	Remark
1-1	Normal PPS (from MG – UAT)	Normal operation	
1-2	Normal PPS (from Grid – MT - UAT)	MG not in service	
2	Alternate PPS (from Grid - SAT)	Loss of normal PPS	
3	EDG	LOOP	
4	AAC-GTG	SBO	Train A and B only
5	Mobile DG	BDBEE (Extended SBO)	Train A and B only

8.3 Onsite Power System

❖ Onsite DC Power System (§ 8.3.2) – Class 1E

- Class 1E 125 Vdc Power System



✓ Functions: supplies reliable 125 Vdc power to various plant safety equipment.

✓ Components: battery, battery charger (N+1), DC control center, and distribution Panels

✓ Major loads:
- ➢ Class 1E motor operated valves;
- ➢ Solenoid for pneumatic valves;
- ➢ NSSS and BOP Class 1E control and instrumentation systems;
- ➢ IP inverter.

✓ Redundancy: two redundant divisions (Div. I: Train A plus C, Div. II: Train B plus D)

✓ Independence:
- ➢ Located in separate location (quadrant division arrangement)
- ➢ No interconnection or load share between trains
- ➢ Physical separation meets IEEE Std. 384 (endorsed by RG 1.75)

8.3 Onsite Power System

❖ Onsite DC Power System (§ 8.3.2) – Class 1E

- Battery size and duty cycles

Train	Battery size	Duty cycle
A & B	2800 AH	8hr
C & D	8800 AH	16hr (40hr)

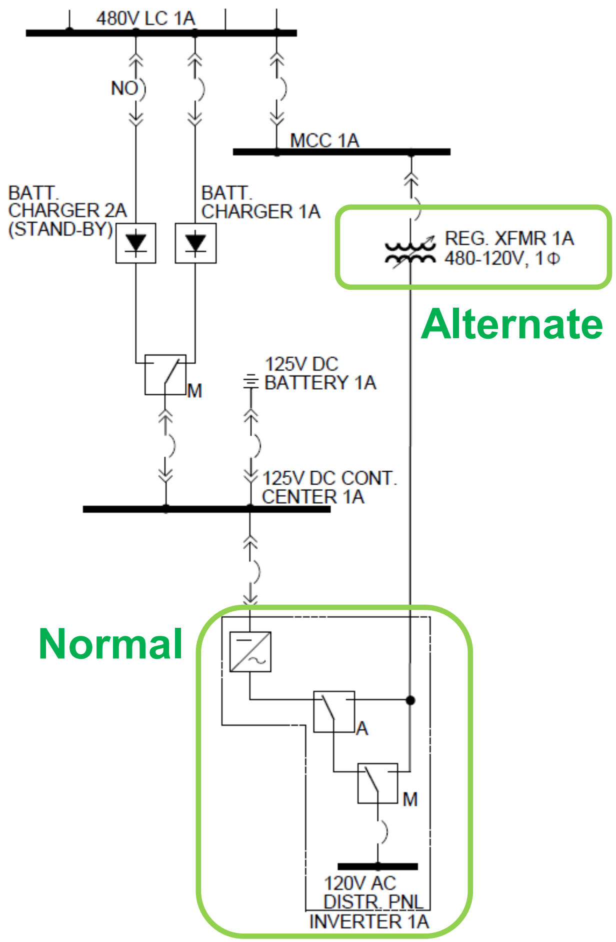
✓ 16 hour duty cycle (without load shedding) is considered for DC Trains C and D to support Trains C and D plant equipment (e.g., TDAFWP) during an SBO.

✓ With load shedding (initiated at 8hr from the onset of an SBO), the battery depletion time for DC Trains C and D is extended to 40 hours.

8.3 Onsite Power System

❖ Onsite DC Power System (§ 8.3.2) – Class 1E (cont.)

- Class 1E 120 Vac Instrumentation and Control Power (IP) System



✓ Functions: supplies reliable uninterruptible 120 Vac power to plant safety I&C equipment.

✓ Major loads:
  - ➢ Safety Consoles;
  - ➢ Plant Protection System (PPS);
  - ➢ ESF-CCS;

✓ Major components: Inverter, Regulating Transformer, Automatic/Manual Transfer Switch and Distribution Panel

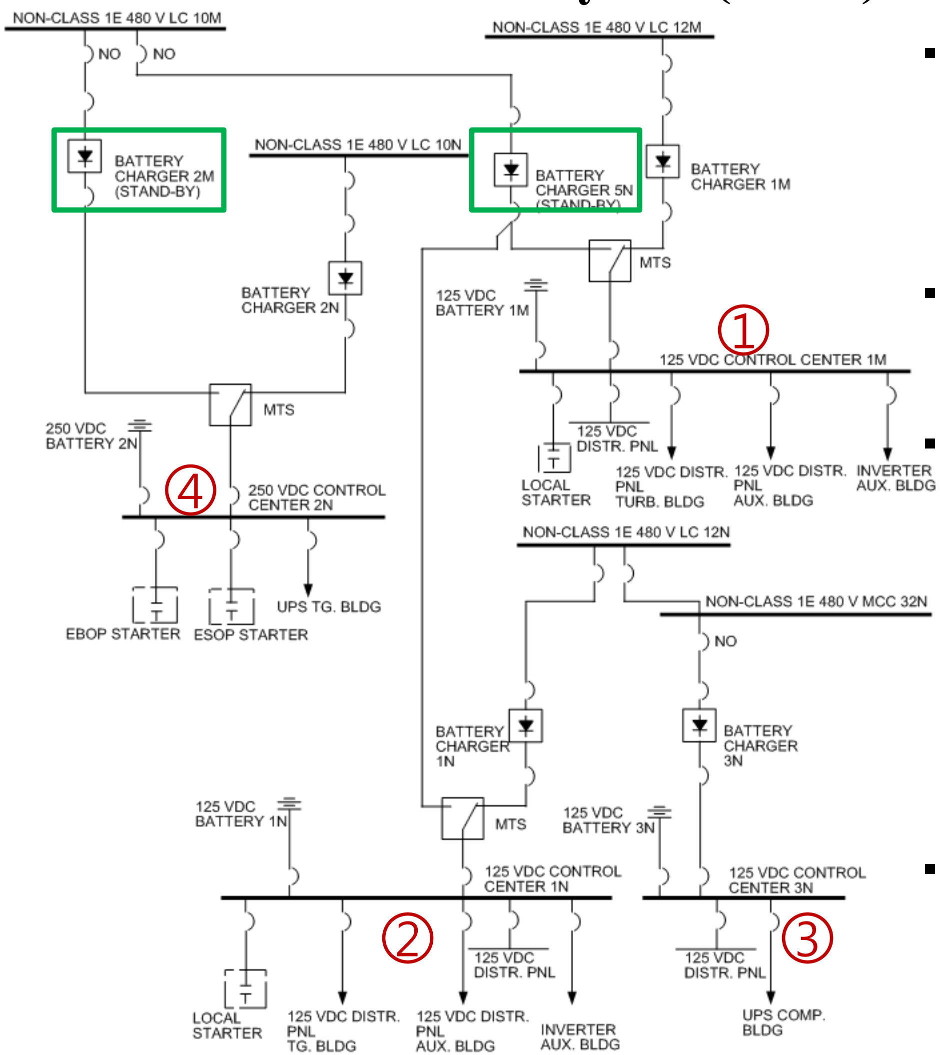
✓ Major components (e.g., inverters, regulating transformers) have sufficient capacity and capability to perform their intended function

✓ Normal feed: inverter (with battery back-up)

✓ Alternate feed: regulating transformer (no battery back-up)

8.3 Onsite Power System

❖ Onsite DC Power System (§ 8.3.2) – Non-Class 1E



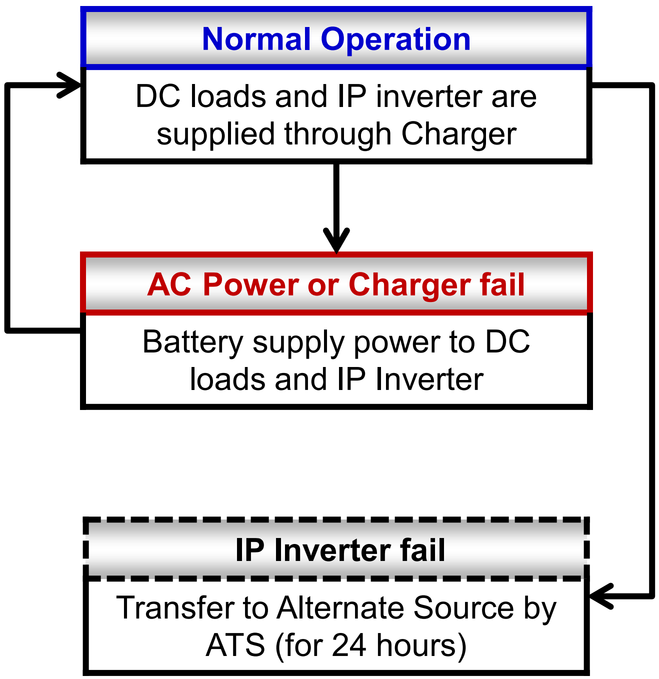
- Functions: supplies reliable 125 Vdc and 250 Vdc power to various plant non-safety equipment (e.g., NSSS and BOP system LCPs, solenoid for pneumatic valves, T/G emergency loads, emergency lighting, etc.)
- Each dc power subsystem consists of battery, battery charger (BC), DC control center, and distribution panels
- Size of batteries and battery chargers

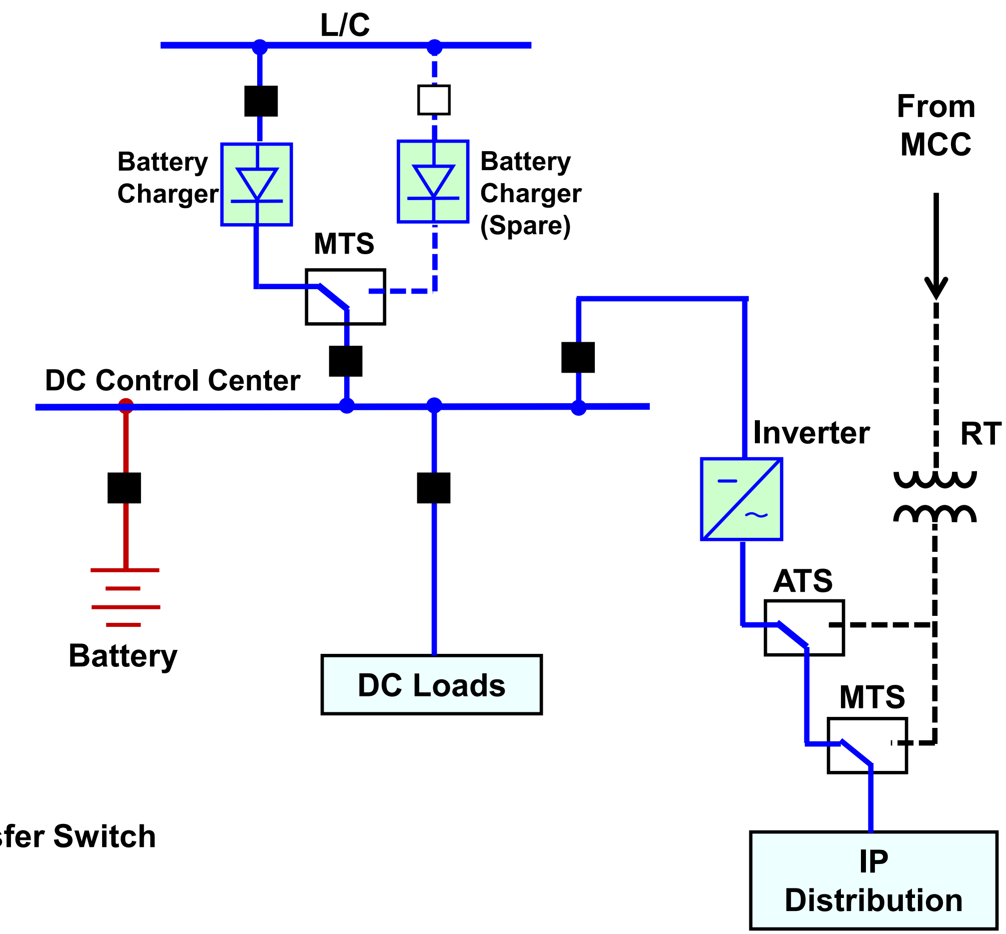
Item	Location	Volt.	BC output	Battery Capacity
1	Aux. Bldg. (Div. I)	125 V	1,800 A	4,000 AH
2	Aux. Bldg. (Div. II)	125 V	1,600 A	3,600 AH
3	Compound Bldg.	125 V	300 A	700 AH
4	Turbine Bldg.	250 V	600 A	3,200 AH
5	AAC Bldg.	125 V	200 A	500 AH

- Standby BCs are applied to 250 Vdc subsystem for T/G auxiliary loads and 125 Vdc subsystems for IP loads in the Aux. Bldg.

8.3 Onsite Power System

❖ Operation Characteristics of DC and IP System (§ 8.3.2)

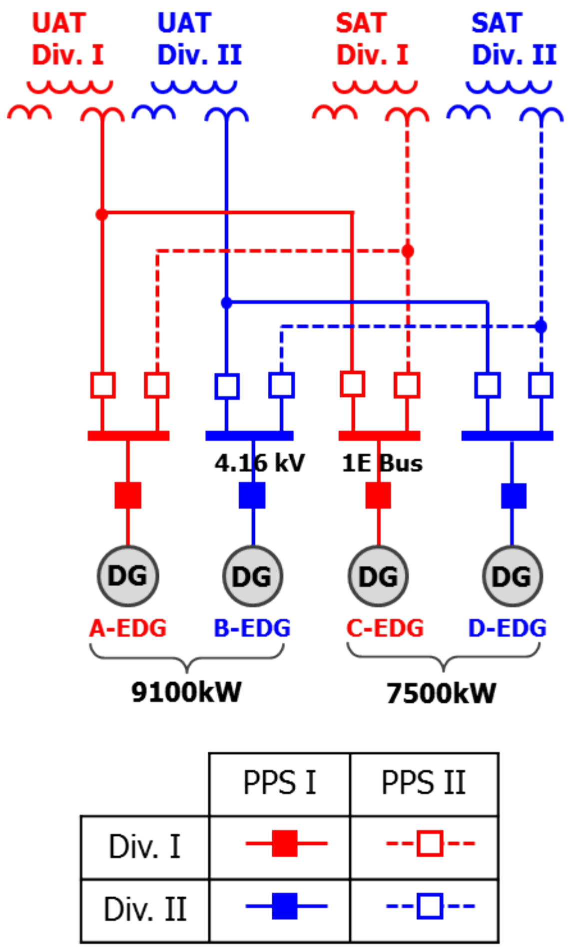




- ATS/MTS : Automatic / Manual Transfer Switch
- RT : Regulating Transformer

8.3 Onsite Power System

❖ Emergency Diesel Generators (§ 8.3.1)



- The EDG is designed in accordance with NRC RG 1.9 and IEEE 387.
- The Class 1E ac power system consists of two redundant load groups (Div. I: Train A and Train C; Div. II: Train B and Train D) and each load group has two EDGs.
- **<u>Four 4.16 kV Class 1E EDGs</u>** provide backup power to the corresponding Class 1E 4.16 kV buses **<u>in the event of a LOOP or a LOOP concurrent with a DBA</u>**.
- The EDG unit has the minimum target reliability factor of **<u>0.95</u>** based on RG 1.9 and RG 1.155.
- Procedures for monitoring and maintaining the EDG reliability will be established by COL applicant to verify that the target is achieved (COL 8.3(11)).
- EDG starting signals: ESF actuation signals (SIAS, AFAS, CSAS) and an under-voltage (27P/27S) signal.
- One of two divisions is sufficient to meet the emergency load requirements for a safe shutdown during a LOOP concurrent with a LOCA condition.

8.3 Onsite Power System

❖ Emergency Diesel Generators (§ 8.3.1)

- Each Class 1E EDG has the following continuous load rating with the margin of 10 percent and its margin meets the requirement of RG 1.9:

Train A and Train B: 9100 kW	Train C and Train D: 7500 kW

- The 4.16 kV Class 1E loads for the EDG (Train A and Train C) are listed in the table below and those for Train B and Train D are identical to Train A and C respectively (DCD Tier 2 , Table 8.3.1-2):

Train A	Train C
Safety Injection Pump 1	Safety Injection Pump 3
Cooling Tower Fan 1A	Cooling Tower Fan 2A
Motor Driven Aux. Feedwater Pump 1	-
Shutdown Cooling Pump 1	Containment Spray Pump 1
Component Cooling Water Pump 1A	Component Cooling Water Pump 2A
Essential Service Water Pump 1A	Essential Service Water Pump 2A
Essential Chiller 1A	Essential Chiller 2A

- For 480 V loads, the difference between Div. I and Div. II is minimal and mainly due to different design conditions for the HVAC system.

8.3 Onsite Power System

❖ Emergency Diesel Generators (§ 8.3.1)

- Each EDG with its own control and protection system has no physical and functional interfaces with other trains.
- A dedicated and functionally independent load sequencer and control scheme are provided for each EDG. In the event of an accident condition which requires EDG operation, a start of each EDG is initiated irrespective of the conditions of the other trains.
- Each EDG is designed to be started automatically and attain a rated voltage and frequency within 17 seconds after receipt of a start signal.
- Loading sequence times (5 to 30 seconds) represent the time immediately after the 17 seconds from the onset of a LOOP and the EDG output breaker is closed.
- The EDG load sequencers automatically sequence the required loads on the Class 1E 4.16 kV buses and the required safety-related loads are connected to the buses in the predetermined order and interval time.
- Each EDG train and its associated auxiliaries are installed in a separate room within physically separate seismic Category I structures.
- EDG support systems: EDG fuel oil system, EDG engine cooling system, EDG starting air system, EDG lubrication system, air intake and exhaust system and HVAC system.

8.3 Onsite Power System

❖ Emergency Diesel Generators (§ 8.3.1)

- All signals of the protective relay trip, except the trip signals listed in the table below, are bypassed during the operation of the EDG under emergency condition:

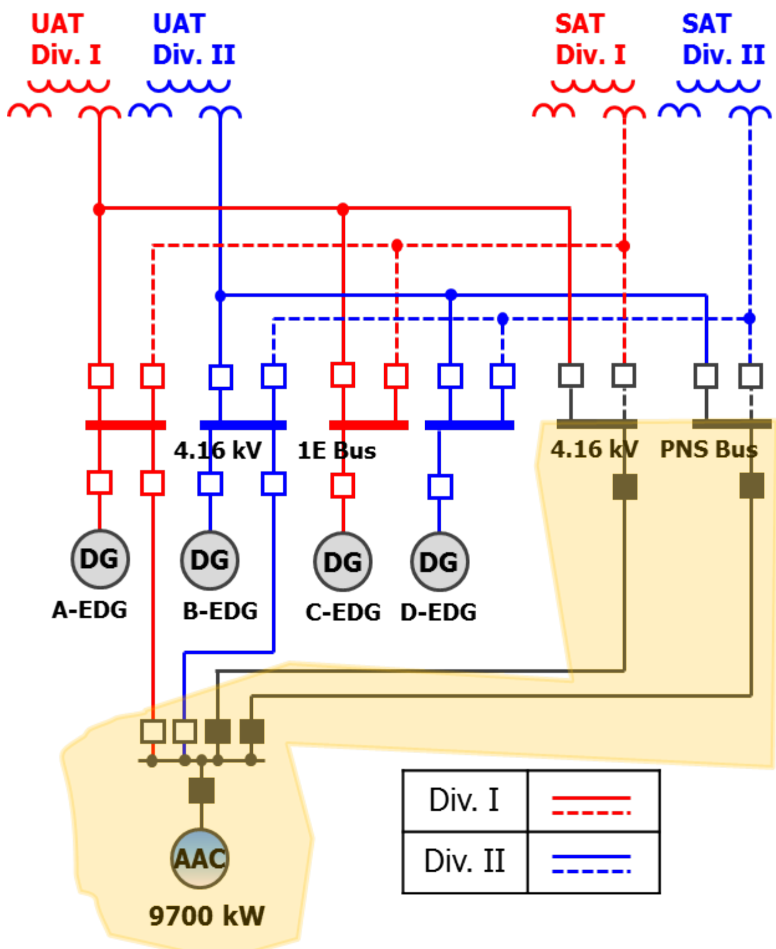
✓ Engine over-speed	✓ Generator differential current
✓ Manual emergency trip	✓ Diesel engine stop lever

- Alarms from the relays in the table below are provided in the MCR and RSR:

✓ Differential/over-speed/emergency stop	✓ Reverse Power
✓ Loss of field	✓ Overcurrent with voltage restraint
✓ Ground overvoltage	✓ Phase (negative phase sequence) unbalance
✓ Diesel generator fail to start	✓ Running unloaded
✓ Cranking	✓ Subsystem trouble

8.3 Onsite Power System

❖ Alternate AC Gas Turbine Generator (§ 8.3.1)



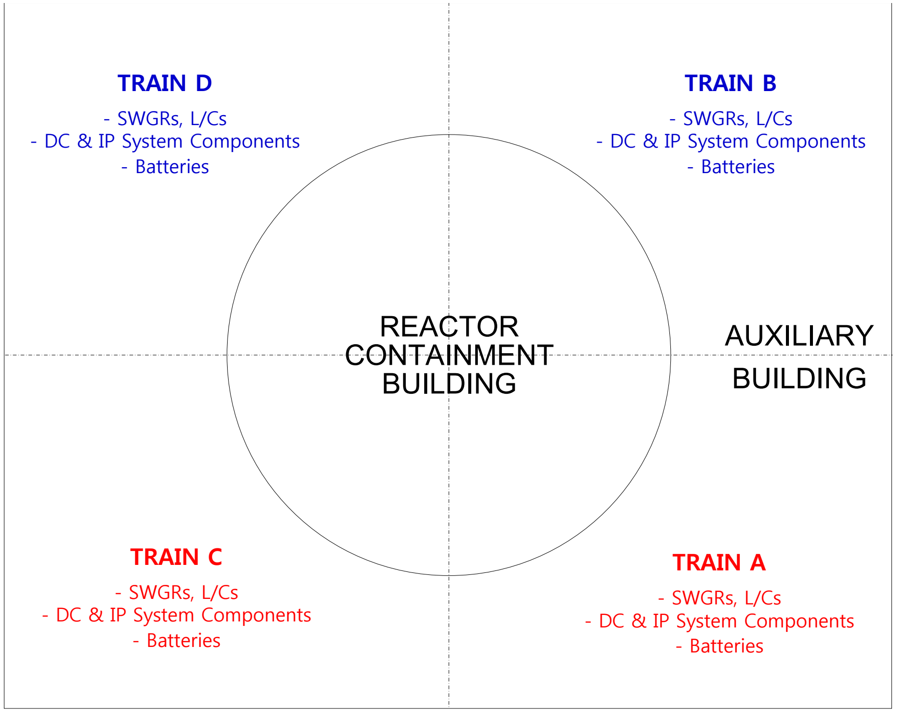
- Two permanent non-safety (PNS) buses are powered by the 4.16 kV Non-Class 1E AAC GTG during a LOOP.
- Automatically started by a starting signal from an under-voltage relay and manually connected to two PNS buses during a LOOP.
- AAC source rating (9700 kW) is adequate to meet the load requirements during a LOOP condition.

Major PNS Loads during a LOOP	
✓ Central Chillers 1/2/3/4	Total load capacity with a margin (10%): **Appx. 6857 kW**
✓ Central Chilled Water Pumps 1/2	
✓ T/G Auxiliaries	
✓ Non-1E DC and IP loads	
✓ Essential Lighting	

8.3 Onsite Power System

❖ Equipment Layout (Quadrant Divisions) (§ 8.3.1)

- Each Train of the Class 1E power system located in a seismic Category I structure, is separated so that a single failure does not cause multiple malfunctions or interactions between trains.
- No interconnection or inadvertent closure of interconnecting devices between redundant divisions.
- The physical separation between the redundant equipment including cables and raceways is designed in accordance with IEEE 384 (RG 1.75)
- Cables of each train run in separate raceways are physically separated from cables of the other trains and so do raceways.



8.4 Station Blackout (SBO)

❖ Design Requirements – 10 CFR 50.63

- Sufficient capacity and capability to ensure that the core is cooled and appropriate containment integrity is maintained in the event of a station blackout for the specified duration.
- Acceptable capability to withstand station blackout provided an analysis is performed which demonstrates that the plant has this capability from onset of the station blackout until the alternate ac source(s) and required shutdown equipment are started and lined up to operate.
- If the AAC source is aligned to the shutdown bus within 10 minutes of the onset of station blackout, then no coping analysis is required.

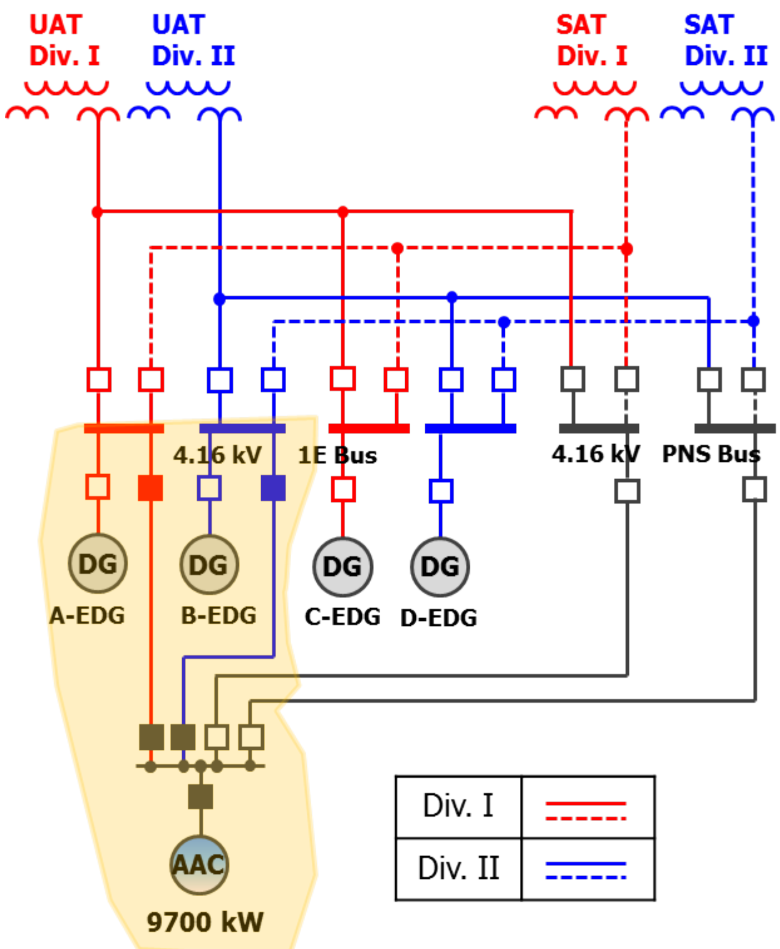
8.4 Station Blackout (SBO)

❖ Station Blackout (§ 8.4.1)

- The 4.16 kV non-Class 1E AAC GTG is designed in accordance with 10 CFR 50.63, RG 1.155 and NUMARC 87-00.
- During an SBO, the AAC GTG with sufficient capacity, capability, and reliability provides power for the set of required shutdown loads to bring the plant to safe shutdown (i.e., hot shutdown condition).
- When two (Train A and Train B) of the four EDGs are unavailable during a LOOP in the APR1400, the AAC GTG shall be manually aligned.

8.4 Station Blackout (SBO)

❖ Station Blackout (§ 8.4.1)



- Manually connected to the designated 4.16 kV Class 1E switchgear (**Train A or Train B**) by the operator **within 10 minutes** from the beginning of an SBO event.
- Connection from the AAC GTG to the shutdown bus via two normally open circuit breakers
- SBO coping duration is **16 hours** as determined conservatively based on RG 1.155.

EAC configuration group	C
EDG reliability	0.95
Offsite Power Design Characteristic Group	P3

NB) COL applicant is to validate the SBO coping duration by the method specified in RG 1.155 (COL 8.4(3)) .

8.4 Station Blackout (SBO)

❖ Station Blackout (§ 8.4.1)

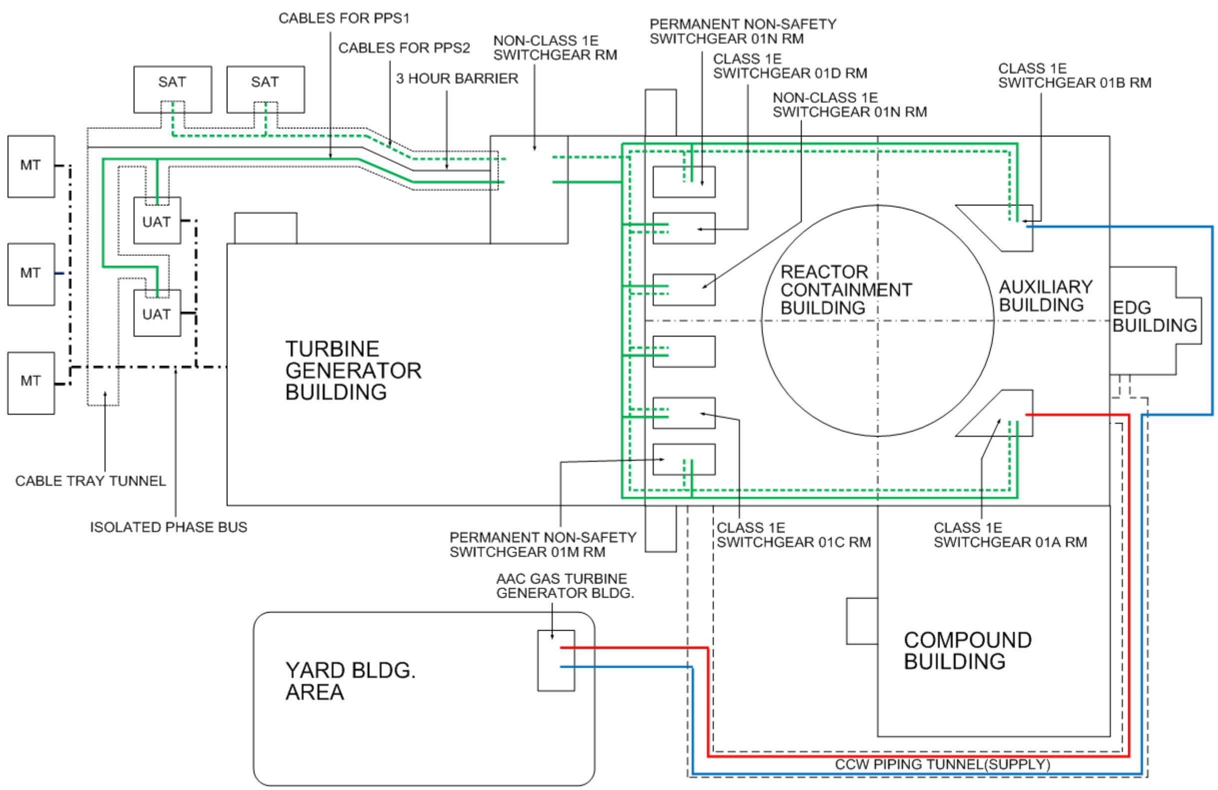
- The AAC GTG is started automatically and designed to attain rated voltage and frequency within 2 minutes after receipt of a starting signal.
- The loads required for plant safe shutdown are manually connected by the operator in the main control room and remote shutdown room.
- To minimize the potential for common-cause failures with the onsite Class 1E EDGs, the AAC GTG is provided with a gas turbine engine with a diverse starting and cooling system according to the requirement of Criterion 2 for RG 1.155 position C.3.3.5.
- Periodic testing and inspection of the AAC GTG will be implemented according to the requirement of Criterion 5 for RG 1.155 position C.3.3.5 to demonstrate equipment operability and reliability.
- COL applicant develops the detailed procedures for manually aligning the AAC GTG to the safety buses (Train A or Train B) during an SBO (COL 8.4(2)).

NON-PROPRIETARY

8.4 Station Blackout (SBO)

❖ Station Blackout (§ 8.4.1)

- The AAC GTG including the related auxiliary equipment, is installed in a separate building.
- Cables from the AAC GTG to the shutdown buses are separate from the cables from the PPS sources.



Chapter 8 Open Items Summary

❖ RAI 8426, Question 08.01-14

- Date of issue: December 17, 2015
- Description of issue
  - ✓ Provide explanation as to how the proposed design meet GDC 17 requirements, and guidance in SRP 8.3, SECY 91-078, RG 1.32, and industrial standards.
  - ✓ Discuss how the electrical system provides a direct connection with no intervening non-safety buses from the offsite power source to the onsite Class 1E system.
- Position:
  - ✓ The APR1400 offsite power system has direct connections to the safety buses (Class 1E buses) without any intervening non-safety buses.
  - ✓ The APR1400 offsite power system does include common transformer windings in the UATs and SATs being connected to both safety (Class 1E) buses and non-safety (non-Class 1E) buses similar to existing NPPs which did not modify the design.
  - ✓ Additional protection from a fault on a non-safety bus provided by two incoming circuit breakers in series.

Chapter 8 Open Items Summary

❖ RAI 8426, Question 08.01-14 (cont.)

- Path for resolution:
  - ✓ KHNP provided a detail discussion (via a white paper) on the design compliance of APR1400 with SECY 91-078 requirements.
  - ✓ NRC OGC reviewing KHNP's position.
  - ✓ KHNP response pending NRC feedback on the KHNP position.
- RAI 8426, Question 08.01-14 is being tracked as 4 open items in different sections (§ 8.1, § 8.2 & § 8.3) of the draft SER.

Chapter 8 Open Items Summary

❖ RAI 8521, Question 08.02-11

- Date of issue: March 28, 2016
- Description of issue: with regard to the open phase conditions (OPCs), the applicant is requested to provide the following:
  - ✓ the detail scheme design to detect and automatically respond to OPCs;
  - ✓ a summary of analysis for ground-faults and OPCs; required surveillance test; ITAAC, etc.
- Path for resolution:
  - ✓ KHNP has performed a design vulnerability study including sufficient analyses needed to characterize and quantify the safety challenges of OPCs (including high impedance ground faults).
  - ✓ KHNP established the minimum required design feature of open phase detection (OPD) system, and prepared a DCD mark-up which incorporated the design features of OPD system, necessary COL items, and ITAAC.
  - ✓ KHNP provided a formal response for NRC staff's review and concurrence.
- Status: awaiting NRC review and concurrence

Current Status

- Chapter 8 is on a success path for completion on schedule.
- A draft SER with Open Items was issued as of October 27, 2016
  - Contains two technical issues (five open items) and a path for closing each open item has been discussed with the NRC Staff and is being implemented.
- Changes in Chapter 8 as reviewed and marked-up in response to NRC's RAIs will be incorporated into the next revision of the DCD, Tier 2.

Summary

- Chapter 8 adequately describes the design features of the electric power system of APR1400 standard plant.

- The APR1400 electric power system design complies with US NRC regulatory requirements, properly meets its endorsed codes and standards, and therefore, provides reasonable assurance of
  - ① Reliable operation of the plant, and
  - ② Safety functions for the plant.

Attachments

❖ List of Submitted Documents for Chapter 8

Document No.	Title	Revision	Type	ADAMS Accession No.
APR1400-K-X-FS-14002 -NP	APR1400 Design Control Document Tier 2: Chapter 8 Electric Power	0	DCD	ML15006A047
APR1400-K-X-IT-14001 -P & NP	APR1400 Design Control Document Tier 1, Section 2.6	0	DCD	ML15006A039
APR1400-E-E-NR-14001 -P & NP	Onsite AC Power System Analysis Technical Report	1	TER*	ML16015A420

* Technical Report "Onsite AC Power System Analysis Technical Report" (Rev.1) was submitted as part of the response to RAI 148-8104, Question 08.03.01-13.

❖ RAI Summary

No. of Questions	No. of Responses	Not Responded	No. of Open Items
76	75	1*	5**

* RAI 333-8426, Question 08.01-14 (SECY 91-078 issue) has not been responded to.

** Four open items are related to RAI 333-8426, Question 08.01-14 and one open item is related to RAI 453-8525, Question 08.04-11 (OPC issue).

Attachment : List of COL Items for Ch. 8 (1/5)

COL Identifier	Description
COL 8.2(1)	The COL applicant is to identify the circuits from the transmission network to the onsite electrical distribution system that are supplied by two physically independent circuits.
COL 8.2(2)	The COL applicant is to provide information on the location of rights-of-way, transmission towers, voltage level, and length of each transmission line from the site to the first major substation that connects the line to the transmission network.
COL 8.2(3)	The COL applicant is to describe the switchyard voltage related to the transmission system provider/operator (TSP/TSO) and the formal agreement between the nuclear power plant and the TSP/TSO. The COL applicant is to describe the capability and the analysis tool of the TSP. The COL applicant is also to describe the protocols for the plant to remain cognizant of grid vulnerabilities.
COL 8.2(4)	The COL applicant is to describe and provide layout drawings of the circuits connecting the onsite distribution system to the preferred power supply.
COL 8.2(5)	The COL applicant is to describe the site-specific design for the switchyard equipment, including breaker arrangement, electrical schematics of breaker control system, protective devices and their settings, and auxiliary power supplies (ac and dc) for control and protection.
COL 8.2(6)	The COL applicant is to provide an FMEA of the switchyard components to assess the possibility of simultaneous failure of both circuits as a result of single events. In addition, the COL applicant is to provide the results of grid stability analyses to demonstrate that the offsite power system does not degrade the normal and alternate preferred power sources to a level where the preferred power sources do not have the capacity or capability to support the onsite Class 1E electrical distribution system in performing its intended safety function.

Attachment : List of COL Items for Ch. 8 (2/5)

COL Identifier	Description
COL 8.2(7)	The COL applicant is to design the offsite power system to detect, alarm, and automatically clear a single-phase open circuit condition.
COL 8.2(8)	The COL applicant is to describe how testing is performed on the offsite power system components and identify the potential effects that must be considered during testing.
COL 8.2(9)	The COL applicant is to provide the required number of immediate access circuits from the transmission network.

Attachment : List of COL Items for Ch. 8 (3/5)

COL Identifier	Description
COL 8.3(1)	The COL applicant is to provide and to design a mobile GTG and its support equipment.
COL 8.3(2)	The COL applicant is to describe and provide detailed ground grid and lightning protection.
COL 8.3(3)	The COL applicant is to provide testing, inspection, and monitoring programs for detecting insulation degradation of underground and inaccessible power cables within the scope of 10 CFR 50.65.
COL 8.3(4)	The COL applicant is to provide protective device coordination.
COL 8.3(5)	The COL applicant is to provide the analysis and underlying assumptions used to demonstrate adequacy for insulation coordination of surge and lightning protection.
COL 8.3(6)	The COL applicant is to develop the maintenance program to optimize the life and performance of the batteries.
COL 8.3(7)	The COL applicant is to provide a short-circuit analysis of the onsite dc power system with actual data.
COL 8.3(8)	The COL applicant is to describe any special features of the design that would permit online replacement of an individual cell, group of cells, or entire battery.
COL 8.3(9)	The COL applicant is to provide the analysis for the station and switchyard grounding system with underlying assumptions, based on the site-specific parameters including soil resistivity and site layout.
COL 8.3(10)	The COL applicant is to provide the detailed design of the cathodic protection (GP) system as applicable to the site conditions.

Attachment : List of COL Items for Ch. 8 (4/5)

COL Identifier	Description
COL 8.3(11)	The COL applicant is to establish procedures to monitor and maintain EDG reliability during plant operations to verify the selected reliability level target is being achieved as intended in RG 1.155.
COL 8.3(12)	The COL applicant is to provide the analysis and underlying assumptions used to demonstrate adequacy for power quality limits (harmonic distortion).
COL 8.3(13)	The COL applicant is to establish Administrative Program(s), including application of dedicated cable and raceway management database tool as necessary, which is (are) developed on the basis of the cable and raceway numbering system to efficiently manage cable routing and cable termination and verify that the cable design fulfills the acceptance criteria (i.e., separation, filling criteria, and ampacity).
COL 8.3(14)	The COL applicant is to provide a bus transfer study of the onsite power system. Based on the bus transfer study, the COL applicant is also to provide final relay selection and settings for the bus transfer.
COL 8.3(15)	The COL applicant is to conduct periodic inspection and testing of the protection devices for the EPA conductors. All circuit breakers for the EPA conductors shall be inspected and tested in 60 months, low voltage circuit breaker overcurrent protection devices for the EPA conductors shall be inspected and tested once per 18 months for 10 % of each type of circuit breakers, and overcurrent relay for medium voltage circuit breakers for the EPA conductors shall be inspected and tested once per 18 months.

Attachment : List of COL Items for Ch. 8 (5/5)

COL Identifier	Description
COL 8.4(1)	The COL applicant is to identify local power sources and transmission paths that could be made available to resupply power to the plant following the loss of a grid or the SBO.
COL 8.4(2)	The COL applicant is to develop detailed procedures for manually aligning the alternate AC power supply when two (Trains A and B) of the four diesel generators are unavailable during a loss of offsite power event.
COL 8.4(3)	The COL applicant is to validate the SBO coping duration according to the method specified in RG 1.155.

Attachment: Acronyms (1/3)

- AAC: Alternate Alternating Current
- AB: Auxiliary Building
- AC : Alternating Current
- AFAS: Auxiliary Feedwater Actuation System
- ATS: Automatic Transfer Switch
- BC: Battery Charger
- BDBEE : Beyond Design Basis External Event
- BOP : Balance of Plant
- CFR: Code of Federal Regulations
- COL : Combined License
- COLA : Combined License Applicant
- CSAS: Containment Spray Actuation System
- D/G : Diesel Generator
- DBA: Design Basis Accident
- DC: Direct Current
- DCD: Design Control Document

Attachment : Acronyms (2/3)

- EDG: Emergency Diesel Generator
- ESF-CCS: Engineered Safety Features – Component Control System
- FMEA: Failure Modes and Effects Analysis
- GCB: Generator Circuit Breaker
- GTG: Gas Turbine Generator
- HVAC: Heating, Ventilation, Air Conditioning
- IEEE: Institute of Electrical and Electronics Engineers
- IP: Instrumentation and control Power
- IPB: Isolated Phase Bus
- KHNP: Korea Hydro & Nuclear Power Company
- L/C: Load Center
- LOCA: Loss-of-Coolant Accident
- LOOP: Loss-of-Offsite Power
- MCC: Motor Control Center
- MCR: Main Control Room
- MG: Main Generator
- MT: Main Transformer
- MTS: Manual Transfer Switch

Attachment : Acronyms (3/3)

- MV: Medium-Voltage
- NEMA: National Electrical Manufacturers Association
- NPP: Nuclear Power Plant
- NRC: U.S. Nuclear Regulatory Commission
- NSSS: Nuclear Steam Supply System
- OGC: Office of General Counsel
- OPC: Open Phase Condition
- OPD: Open Phase Detection
- PNS: Permanent Non-Safety
- PPS: Preferred Power Supply
- RAI: Request for Additional Information
- SAT: Standby Auxiliary Transformer
- SBO: Station Blackout
- SFC: Single Failure Criterion
- SIAS: Safety Injection Actuation System
- SWYD: Switchyard
- UAT: Unit Auxiliary Transformer

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Presentation to the ACRS Subcommittee

Korea Hydro Nuclear Power Co., Ltd (KHNP)
APR1400 Design Certification Application Review

Safety Evaluation with Open Items: Chapter 8

ELECTRIC POWER

NOVEMBER 29, 2016

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Technical Topics

Section 8.1 – Introduction

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Technical Topics

- The APR1400 electric power systems are the source of power for station auxiliaries during normal operation, and for reactor protection system (RPS) and engineered safety features (ESF) during abnormal and accident conditions.

- Staff reviewed the electric power systems to determine whether the systems are designed to have adequate:
  - Capacity
  - Capability
  - Redundancy
  - Independence
  - Testability

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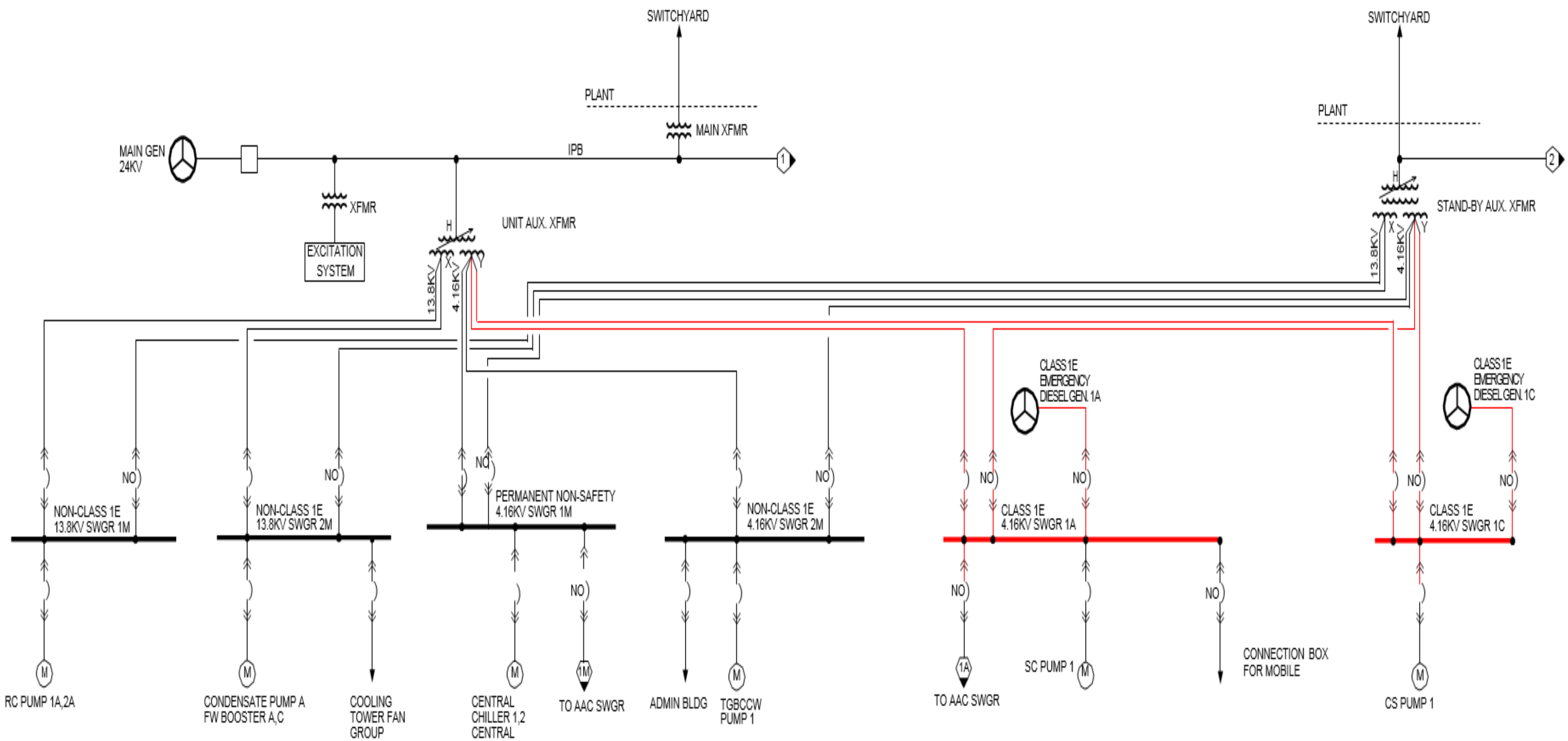
Open Item

- **Conformance to SECY-91-078**: To satisfy GDC 17, SRP 8.2, SRP 8.3, and Commission approved SECY-91-078 "EPRI's Requirements Document and Additional Evolutionary LWR Certification Issues," the following are required:
  - At least one offsite circuit to each redundant Class 1E (safety) division should be supplied directly from one of the offsite power sources with no intervening non-Class 1E (non safety-related) buses in such a manner that the offsite source can power the safety buses if any non-safety bus should fail.
  - An alternate power source to non-safety loads, unless it can be demonstrated that the design will ensure that transients for loss of non-safety power events that are less severe than those associated with the turbine-trip-only.

- The current APR1400 electric power distribution design provides power to the main switchgear through the unit auxiliary transformers (UATs) and standby auxiliary transformers (SATs), where both UATs and SATs have 13.8 kV (non-safety) secondary windings and 4.16 kV (non-safety and safety) secondary windings. Both UAT and SAT have two secondary windings serving both safety and non-safety systems.



SWITCHYARD
PLANT
MAIN XFMR
MAIN GEN
24KV
IPB
1
XFMR
EXCITATION SYSTEM
UNIT AUX. XFMR
H
X
Y
13.8KV
4.16KV
SWITCHYARD
PLANT
2
H
STAND-BY AUX. XFMR
X
Y
13.8KV
4.16KV
CLASS 1E EMERGENCY DIESEL GEN. 1A
CLASS 1E EMERGENCY DIESEL GEN. 1C
NO
NON-CLASS 1E 13.8KV SWGR 1M
NON-CLASS 1E 13.8KV SWGR 2M
PERMANENT NON-SAFETY 4.16KV SWGR 1M
NON-CLASS 1E 4.16KV SWGR 2M
CLASS 1E 4.16KV SWGR 1A
CLASS 1E 4.16KV SWGR 1C
M
RC PUMP 1A,2A
CONDENSATE PUMP A
FW BOOSTER A,C
COOLING TOWER FAN GROUP
CENTRAL CHILLER 1,2 CENTRAL
1M
TO AAC SWGR
ADMIN BLDG
TGBCCW PUMP 1
1A
TO AAC SWGR
SC PUMP 1
CONNECTION BOX FOR MOBILE
CS PUMP 1

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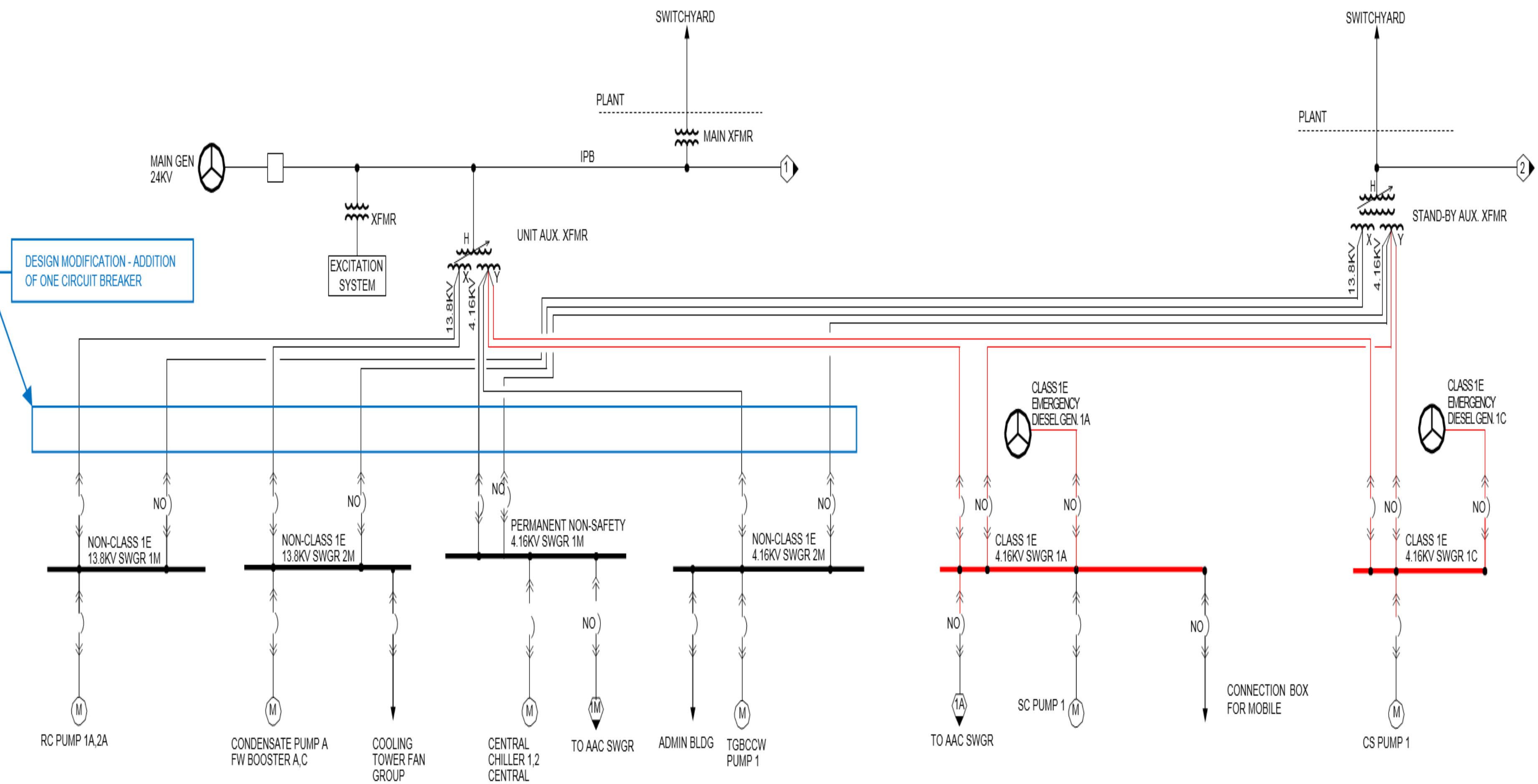
Open Item, continued

- In the first RAI, staff requested that the applicant provide an electric power distribution configuration, such that the failure of the non-safety system does not adversely impact the safety related system from performing its intended function.

- The applicant's response to the first RAI explained that:
  - The power distribution systems are designed in accordance with IEEE Std. 765.
  - Specific failure or fault at a non-Class 1E medium voltage (MV) bus could propagate to the Class 1E buses which are fed from the same SAT or UAT.
  - In order to isolate a potential fault caused by the non-Class 1E system, the power distribution system design change would include two circuit breakers connected in series, as incoming breakers for all non-Class 1E switchgears.

Technical Topics
Section 8.1 – Introduction



Open Item, continued

- The staff issued a follow-up RAI because the proposed design changes did not address SECY-91-078 and associated SRM in addition to the GDC 17 requirement, for the following reasons:
    - The electric power distribution system does not provide a direct connection from the offsite to the onsite Class 1E system with no intervening non-safety buses because a common transformer winding is shared between the two systems.
    - There is potential for the safety systems to be impacted because of failure in the non-safety systems, and the analysis had not been done to support the proposed design changes .
    - IEEE 765 has not been endorsed by the NRC in applicable RGs (RG 1.32, RG 1.75).
- The staff also requested the applicant explain how the proposed design meets GDC 17 and SECY-91-078, and to provide analysis to demonstrate that the design margins will result in transients from a loss of non-safety power event less severe than those associated with turbine trip only event in current existing plant designs.
- Staff is waiting for the applicant to submit revised response to the above RAI, which is an Open Item for both Sections 8.2 and 8.3.1.

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Technical Topics

- The Offsite Power System is the preferred source of power during normal, abnormal, and accident conditions.

- The Offsite Power System comprises of the following major equipment/system:
  - Transmission network, overhead or underground transmission lines, and transmission line towers,
  - Switchyard components and control systems, including switchyard battery systems,
  - Main generator, Generator Circuit Breaker, and Isophase bus duct,
  - Main transformer, unit auxiliary transformers, station auxiliary transformers,
  - Associated electrical components with the above.

Technical Topics
Section 8.2 – Offsite Power System

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Technical Topics

- Staff reviewed the offsite power system to determine whether the system:
  - provides the required minimum of two separate circuits from the transmission network to the onsite distribution system;
  - has adequate capacity and capability to supply power to all safety loads;
  - has both physical and electrical separation between the two (or more) circuits to minimize the chance of simultaneous failure; and
  - includes an interface of the preferred power source with an AAC power source for safe shutdown in the event of an SBO.

- Audit on the methodology and assumptions for the isolated phase bus and generator circuit breaker (GCB).
  - The staff reviewed the summary results and determined that the GCB has the capability of interrupting the maximum asymmetrical and symmetrical fault current and that the design conforms to the methodology provided in SRP 8.2 and IEEE Std. C37.013-1997.

Technical Topics
Section 8.2 – Offsite Power System

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Open Items

- **Conformance with SECY 91-078 -** Requested that the applicant explain how the proposed design meets GDC 17 requirement, and guidance in SECY-91-078. For 8.2, this pertains to how offsite power is supplied to the onsite AC power systems. This issue is discussed in Technical Topics under 8.1.
    - Staff is awaiting formal submittal of the information, after which the staff will complete its evaluation.

- **Open Phase Conditions**– Requested that the applicant explain how its electrical system design would detect, alarm, and respond to a open phase conditions, with/without a high impedance ground
    - Per 10 CFR 52.47(a)(3), the applicant must include principal design criteria for the facility.
    - Staff has determined that, in order to meet the requirements of GDC 17, the applicant should describe how its electrical system design would detect, alarm, and respond to open phase conditions, with/without a high impedance ground.
    - Staff has received the follow-up RAI on November 16, 2016 and are reviewing the response.

Technical Topics
Section 8.3.1 – Onsite AC Power Systems

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Technical Topics

- Onsite AC Power System comprises of the following major equipment/system:
  - Four (4) independent trains of Class 1E AC Power System with Trains A&C for Division I and Trains B&D for Division II
  - Two (2) UATs, connected to generator isophase bus tap and (2) SATs, connected to Grid supplies power to 13.8 kV non-Safety Switchgear, Class 1E 4.16 kV Switchgear, and non-Class 1E Switchgear
  - Four (4) Class 1E Emergency Diesel Generator (back up power for LOOP) connected to Class 1E switchgear of each train
  - One (1) non-Class 1E Gas Turbine Generator as AAC Source (for SBO) connected to permanent non-safety 4.16 kV switchgear

- Staff reviewed the AC system design for the following:
  - redundancy
  - functional independence
  - physical separation of safety and non-safety systems,
  - electrical isolation and single failure criteria
  - testability of the safety equipment and systems

Technical Topics
Section 8.3.1 – Onsite AC Power Systems

- Audit of the Design Calculations.
  - Staff audited electrical power system calculations and distribution system studies. The studies are based on data obtained from a reference plant in Korea.
  - The applicant used ETAP modeling and analysis tool.
  - The staff reviewed the data, acceptance criteria, analysis, and summary results of the studies and accepted the methodology for determining equipment ratings
  - Site-specific calculations/studies will be the COL applicant’s responsibility

- Open Items
  - **Conformance with SECY 91-078** – Requested that the applicant provide explanation how the proposed design meets GDC 17 requirement, and guidance in SRP 8.3, and SECY-91-078. This open item pertains to the onsite power system’s capability, such that the a fault in the non-Class 1E system does not preclude the Class 1E system from performing its intended function. This is discussed in Technical Topics under 8.1.
  - The staff is awaiting formal submittal of the information, after which the staff will complete its evaluation.

Technical Topics
Section 8.3.2 – Onsite DC Power Systems

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Technical Topics

- Onsite DC Power System comprises of the following major equipment/systems:
  - Four (4) independent trains of Class 1E 125 Vdc DC Power Systems; Trains A&C for Division I and Trains B&D for Division II
  - Four (4) independent Class 1E 120 Vac Instrumentation and Control Power Systems; Trains A&C for Division I and Trains B&D for Division II
  - Four (4) non-Class 1E 125 Vdc DC Power Systems
  - One (1) Non-Class 1E 120 Vac Instrumentation and Control Power Systems
- The staff reviewed the configuration of the DC power distribution system for:
  - system redundancy
  - physical separation of safety and non-safety systems
  - electrical isolation
  - single failure criteria
  - testing capability
- The staff concluded that the onsite DC power system adequate capacity and capability.

Section 8.3.2 – Onsite DC Power Systems

Special Features

- Trains A&B Class 1E 125 Vdc batteries have an 8-hour duty cycle (2800 AH).
- Trains C&D Class 1E 125 Vdc batteries have a 16-hour duty cycle (8800 AH)

- Reason for difference in capacity and duty cycle:
  - Trains A&B batteries have a capacity of 2800 AH, which can provide back-up power for 2 hours without load shedding and an additional 6 hours with load shedding.
  - Trains C&D batteries have a capacity of 8800 AH, which can provide back-up power for 16 hours without load shedding. Trains C&D provides power to equipment required during beyond-design-basis-external-event (BDBEE) as per the mitigation strategies guidance. The BDBEE loads are not supplied from Trains A&B.

- The Class 1E batteries are sized in accordance with IEEE-485, and will be qualified according to IEEE-535.

- No Open Items in Section 8.3.2.

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Technical Topics

- The staff reviewed information pertaining to SBO in the DCD to determine whether the design is capable of withstanding (coping with) and recovering from an SBO of a specified duration (i.e., coping duration).

- The design's SBO coping duration is 16 hours. The staff reviewed the methodology for determining the coping duration and concluded that the duration is acceptable.

- For SBO coping capability, the applicant selected an alternate AC (AAC) approach that includes a gas turbine generator (GTG).

- The staff reviewed the AAC power source for compliance with the following criteria:
  - Not normally connected to the offsite power or onsite emergency AC (EAC) power systems,
  - Minimum potential for common mode failure with the onsite EAC power or offsite power sources
  - Available within 1 hour after the onset of an SBO, and
  - Sufficient capacity, capability, and reliability to operate the SBO shutdown loads

- The staff concluded that the AAC power source meets the above criteria.

Technical Topics

Section 8.4 – Station Blackout

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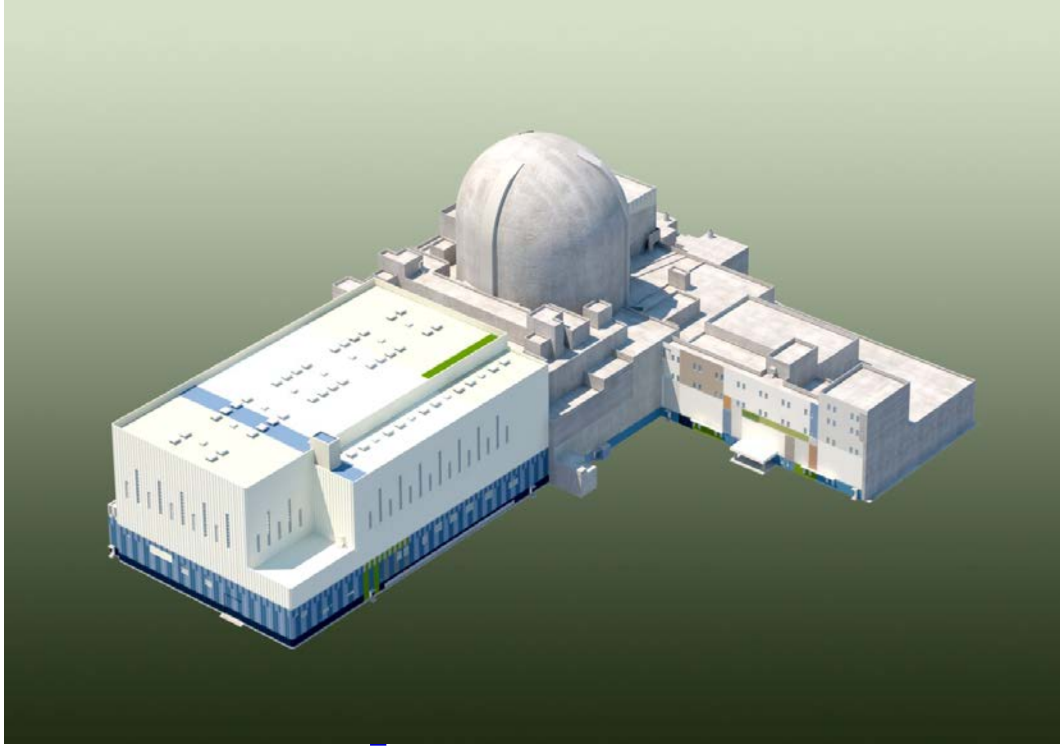
- The staff determined that no coping analysis is required since the AAC GTG power source 1) meets the required criteria and 2) can be demonstrated by test to be available to provide power within 10 minutes of the onset of the SBO.
- The staff concluded that the design has an acceptable SBO coping capability.
- The staff reviewed the design's capability to recover from an SBO and determined recovery is achieved by restoring offsite power or emergency AC power from Train A or Train B EDG.
- No Open Items.

NON-PROPRIETARY

APR1400 DCA
Response to the ACRS Subcommittee Questions on Chapter 2, 5, 10 and 11



KEPCO/KHNP

November 29, 2016

Response to Chap. 2 Questions (1/6)

- **Question 1:** Staff Draft SE (p 2-45): KHNP used the terms "exclusion area boundary" and "site boundary" interchangeably, although these terms are not necessarily the same for all facilities - if KHNP is aware of this and if there is any impact of this.
  - **Response** : The site boundary and exclusion area were used as the same meaning in APR1400.

- **Question 2:** Design basis flood and max ground water level – which bldgs. Outside nuclear island need to be protected water level limits of 1' and 2' below grade level, is part of TG bldg. below these levels? How would a COL applicant know (no COL info item in Ch. 2)?
  - **Response**: The SSCs Important to safety are those structures, systems, and components that provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public as defined in 10 CFR 50 Appendix B, and are protected from an external flood event as provided in DCD Tier 2 Subsection 3.4.1.1.

    The buildings containing important to safety SSCs are Reactor Containment Building, Auxiliary Building, Compound Building, Essential Service Water / Component Cooling Water Heat Exchanger Building, AAC Gas Turbine Generator Building, Emergency Diesel Generator Building and Diesel Fuel Oil Tank, and Turbine Building. The details of classification for SSCs are specified in DCD Tier 2, Table 3.2-1. The DCD Tier 2, Table 2.0-1 addresses water level for important to safety buildings.

Response to Chap. 2 Questions (2/6)

- **Question 3:** Section 2.4.4.2 on dam failures – "artificially large floods" – means what?
  - **Response** : As stated in DCD Tier 2 Subsection 2.4.4, artificially large floods means floods to safety-related facilities of nuclear power plant due to the failure of upstream and downstream water control structures such as dam, reservoir and levee etc..

- **Question 4:** Section 2.4.11, Low water – downstream dam, impoundment of cooling water dikes etc. not addressed, why?
  - **Response**: Downstream water control structures such as downstream dam, impoundment of cooling water dikes etc. are addressed in DCD Tier 2 Subsection 2.4.4.
    According to COL 2.4(1), the COL applicant is to provide site specific hydrologic information addressed in DCD Section 2.4. The plant requirements of minimum safety-related cooling water flow in low water consideration are described in Subsection 2.4.11.5 and any potential failures such as downstream dam, impoundment of cooling water dikes, etc. should meet the requirements.

Response to Chap. 2 Questions (3/6)

- **Question 5:** Section 2.4.12, Ground water – does not address water chemistry, why?
  - **Response** : Groundwater chemistry is site-specific information of groundwater to be provided by COL applicant as mentioned in COL 3.8(5) to examine and monitor the condition of normally inaccessible below-grade concrete for signs of degradation. The limits of ground chemistry (pH>5.5, chlorides<500 ppm, sulfate<1500 ppm) have been added in DCD Tier 2, Subsection 3.8.4.7 through response for RAI 227-8274 Question 03.08.04-9.

- **Question 6:** Question- On slide #15 the ACRS mentioned that in the DCD this chart is not labeled and asked KHNP to fix it in the DCD.
  - **Response**: The labels for each damping value will be added in DCD Figures 2.0-1 and 2.0-2 as shown in next slide.

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Response to Chap. 2 Questions (4/6)

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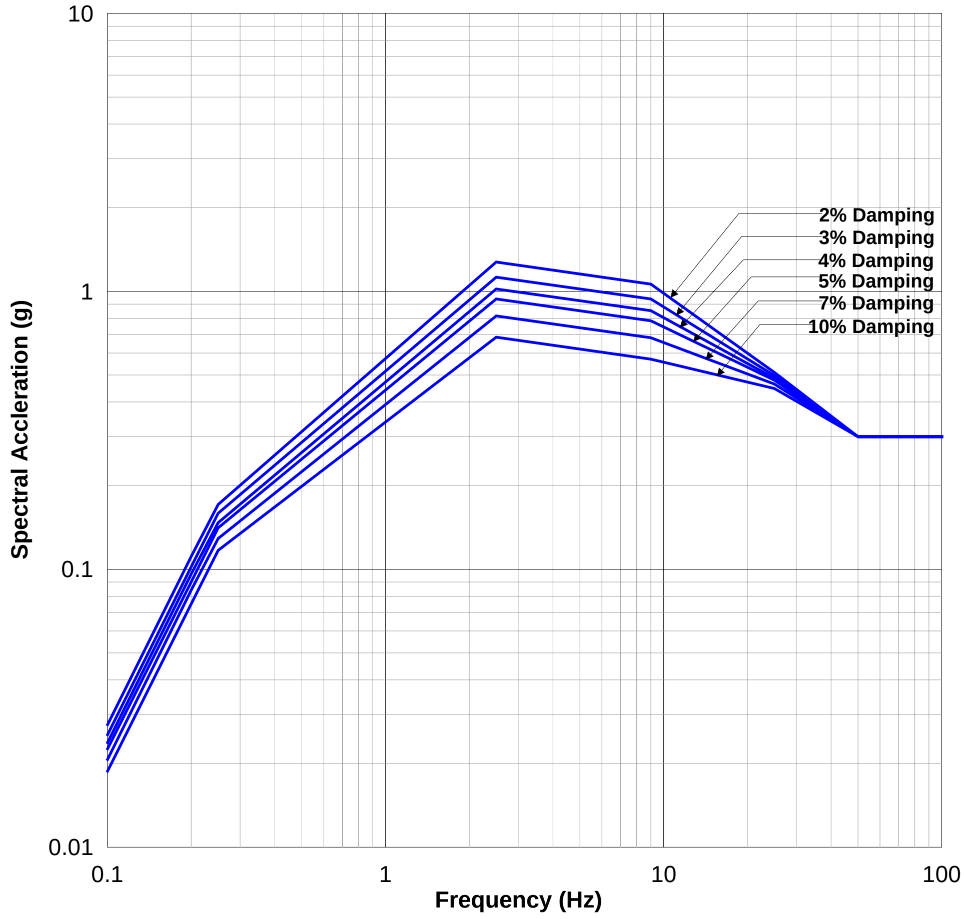

Figure 2.0-1 Horizontal Certified Seismic Design Response Spectra

Response to Chap. 2 Questions (5/6)

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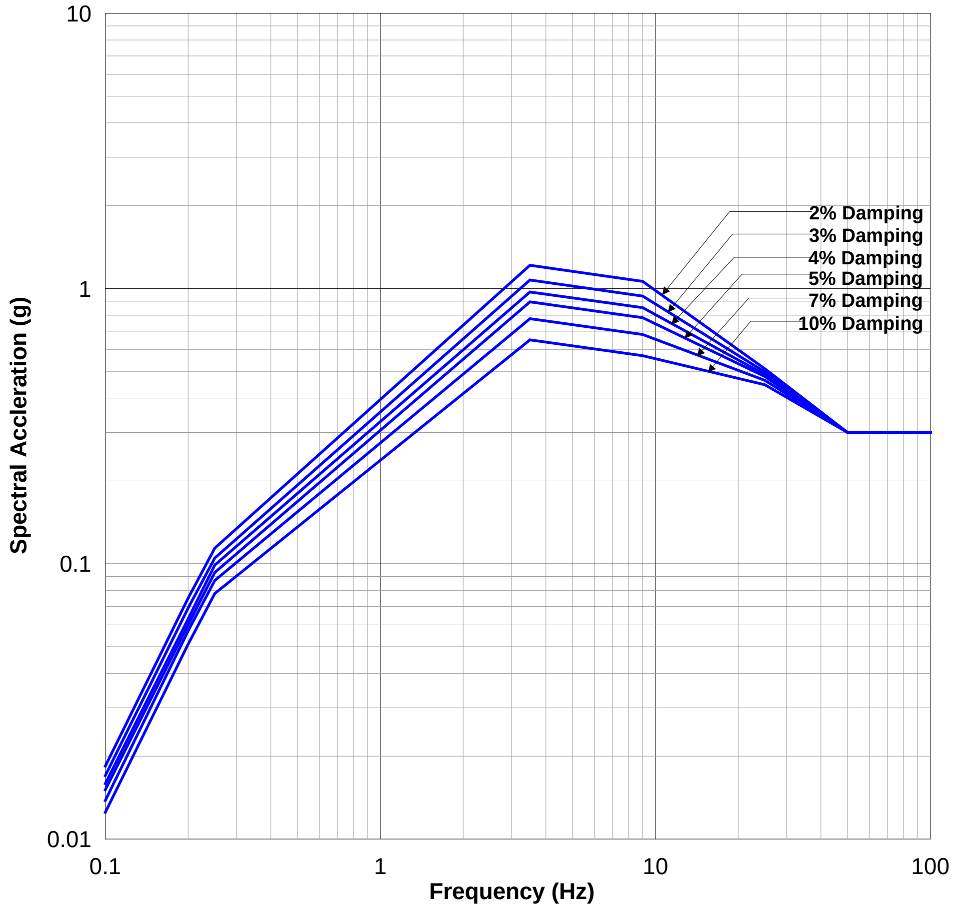


Figure 2.0-2 Vertical Certified Seismic Design Response Spectra

Response to Chap. 2 Questions (6/6)

- **Question 7:** Section 2.5, Seismic, clarify bldgs., tunnels etc. that are in and out of scope of DC related to seismic so that a COL applicant knows.
  - **Response** : For seismic analysis and structural design, the design certification scope is limited to the reactor containment building, the auxiliary building, and the emergency diesel generator building including the diesel fuel oil tank room of Figure 1.2-1 in the DCD. The other seismic Category I buildings, including the component cooling water heat exchanger building and the essential service water building, and the seismic Category II building, such as the turbine generator building, the compound building, and the AAC gas turbine building are designed by the COL applicant. The yard structures such as seismic Category I buried conduits, tunnels, and above-ground tanks are out of scope of design certification as described in DCD COL items COL 3.7(6) and COL 3.7(7). The detailed information was provided in the response to RAI 252-8299 Question 03.07.02-15.

- **Question 8:** On slide #20 7b….why 3.0 inch between buildings. How do we justify 3.0 inch between buildings when other applicants use 0.5 inch.
  - **Response** :

    Maximum allowable differential settlement between buildings is,

    - 76.2 mm (3.0 in.) between NI Common Basemat and EDG Building & DFOT Building
    - 12.7 mm (0.5 in.) between other adjacent buildings

    Between NI building and EDGB & DFOT, there are no connecting systems except electrical cable. The electrical cable installation has enough flexibility to allow 3.0 inch differential settlement.

Response to Chap. 5 Questions (1/15)

- **Question 1:** Confirm Section 3.9.1 addresses the number of transients that are included in 60 year design life consideration of RCPB (e.g., reverse flow conditions).

  - **Response**:

    The APR1400 design basis initiating events and frequencies(the number of transients) including reverse flow conditions used in the stress analysis of ASME Code Class 1 and Class CS components of the primary system are shown in DCD Table 3.9-1, "Transients Used in Stress Analysis."

Response to Chap. 5 Questions (2/15)

- **Question 2:** Sizing basis of RV head vent – natural circulation analysis – what consideration given to loss of loop seal?

  - **Response**:

    RCGV sizing is derived from natural circulation analysis that credits the RCS depressurization using RCGV function. Also the RCGV sizing is sufficient to meet the EPRI URD requirement. The EPRI URD requirement requires that the RCGV shall have sufficient capacity to vent one-half of the RCS volume in one hour, with the vented volume expressed in standard cubic feet of gas over the range of venting conditions considered, assuming a single failure.

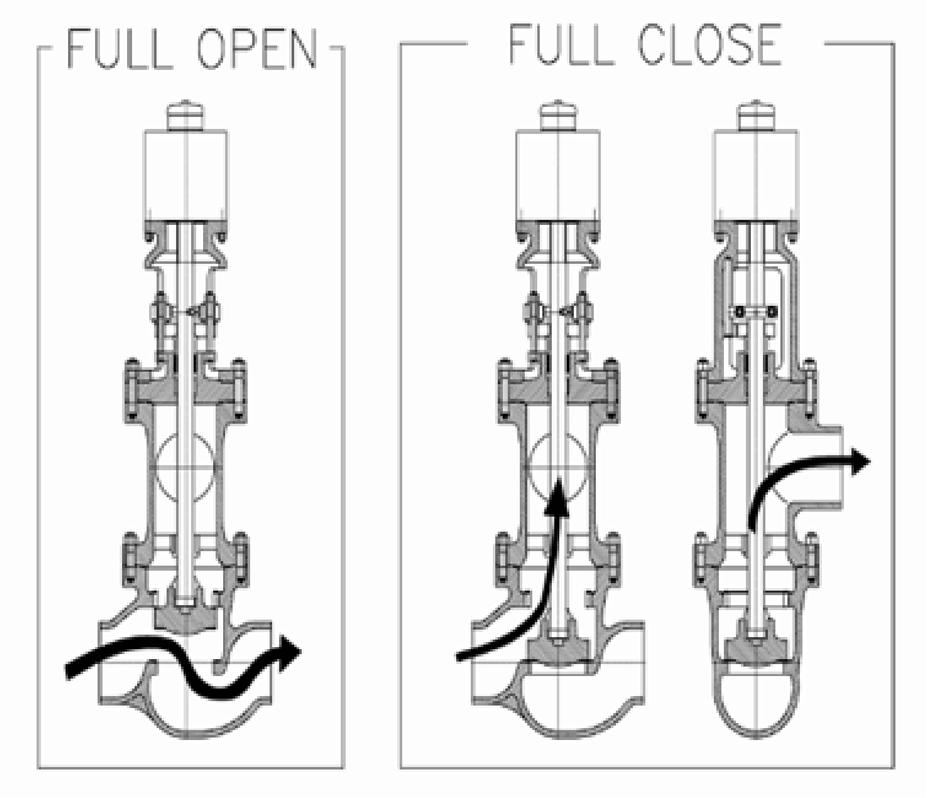
    Loss of loop seal is not considered because there is no loop seal in RCGVS.

Response to Chap. 5 Questions (3/15)

- **Question 3:** Configuration of 3-way valves what prevents internal blocking – confirm Chapters 3 and 19 describes valves.

  - **Response**:

    As shown in figure, there is no possibility of three-way valve being blocked because it is designed to change flow direction only. Therefore, flow is always open under all circumstances.



Response to Chap. 5 Questions (4/15)

- **Question 4:** Slide 9 – POSRV spring is made of Alloy 750, what heat treatment is done?

  - **Response**:

    The POSRV spring materials of SKN 3&4, reference plant of APR1400, are as follows, not Alloy 750.

    - Main Valve spring : X10CrNi18-8 austenitic Stainless Steel
    - Spring Loaded Pilot Valve spring : CrSi Alloy Steel

    Heat treatment is not specified – follow vendor recommendation.

Response to Chap. 5 Questions (5/15)

- **Question 5:** LTOP over-pressure release and staff RAI on energy input – what uncertainty considerations for relief valve setting?

- **Response**:

  One of the design basis events for the LTOP valve sizing is energy addition event, at which the heat transfer from the S/G secondary side to primary side was analyzed. The temperature difference was assumed to be 250°F conservatively, while actual temperature difference in the operating procedure is maximum 100°F. (See NRC RAI 487-8609). Big difference in the temperature causes a rapid and high pressurization.

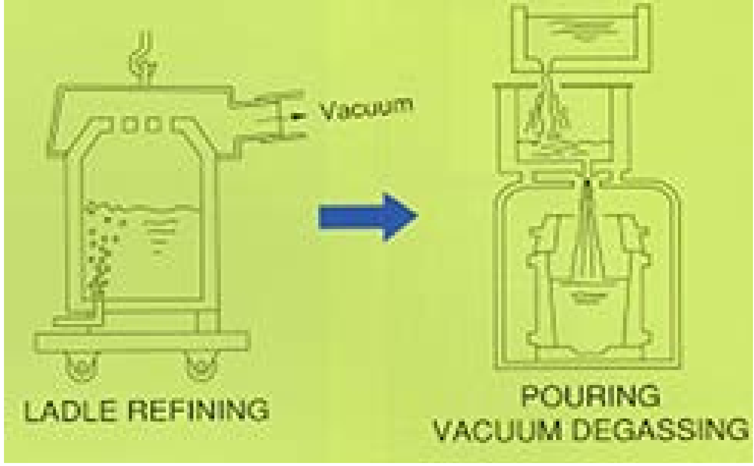
  The maximum temperature difference condition was assumed as follows;

  - The LTOP valves are connected to the RCS (i.e., the SCS suction isolation valves are open) when the RCS temperature is below the SCS entry temperature of 350°F.
  - While the RCS cooldown proceeds to the refueling temperature of 120°F, the S/G secondary side temperature was assumed to be maintained as it was (i.e., 350°F).
  - In this condition the maximum temperature difference would be 230°F and 250°F with margin of 20°F was used as an input to the energy addition analysis for the LTOP valve sizing.

Response to Chap. 5 Questions (6/15)

- **Question 6:** What ensures APR1400 RV rings do not suffer the Belgium plant forging issue? Chemical control may not be enough?
  - **Response**:

    Vacuum degassing methods are used for manufacturing of APR1400 RV ring forging for hydrogen removal. Such methods include ladle refining and ladle-to-ingot mold vacuum degassing. Ladle refining furnace is equipped with bottom plugs for argon gas bubbling together with the induction stirring system and vacuum cover. This system is to stir the molten steel and thus promoting the removal of hydrogen. In ladle-to-mold degassing process, the molten steel is poured from the pony ladle into the ingot mold placed in a vacuum chamber. The finished product will then be subjected to UT inspection as per ASME Code NB-2500 requirement to detect any internal flaws.



Response to Chap. 5 Questions (7/15)

- **Question 7:** Table 5.3-7 - Regarding surveillance capsule removal schedule 217 degree and 224 degree locations are very close - why not remove symmetrically around the vessel?
  - **Response**:

    The surveillance capsule with highest lead factor value will be removed for the first time. After the first removal, higher lead factor capsule will be removed earlier. The capsule of EOL removal is also planned with another highest lead factor for predicting a longer period of time.

    (lead factor : the ratio of the neutron flux density at the location of the specimens in a surveillance capsule to the neutron flux density at the reactor pressure vessel inside surface at the peak fluence location) (ASTM E185)

- **Question 8:** RCP Cooling – with no CCW and seal injection available, how long operators have to trip the pump before bearing damage/seal damage/pump vibration happen? What test is done at operating temp and press?
  - **Response**: A brief summary of the test is as follows;
    - The test was run as part of a 50 hour performance test.
    - 30 minutes after loss of CCW, bearing pad temperature was measured and the bearing pad temperature did not reach to a level of deformation.
    - After the test, bearings were inspected and found to be in good condition, no damage to the pads with only normal wear marks.
    - Vibration levels were acceptable throughout the loss of CCW test.
    - That is the basis of the 30 minute continued operation after Loss of CCW.

Response to Chap. 5 Questions (8/15)

- **Question 9:** San Onofre SGs were built to same specification but two units had different experience relative to excessive wear – how APR1400 is confirming it won't happen – is there sufficient operating experience with the codes (EPRI) being used? Resolved?
  - **Response**:

    In case of APR1400 SGs, to prevent upper horizontal tubes from fretting wear, two kinds of design improvement are applied. An eggcrate flow distribution plate (EFDP) is added to reduce the high flow velocity in the central cavity of tube bundle, and vertical tube supports are added to restrict the displacement of upper horizontal tubes. The ATHOS computer program has been used for the design of all the OPR1000 as well as APR1400 SGs over 20 years in Korea.

- **Question 10:** What gives confidence that fluid elastic instability seen at San Onofre is not seen at APR1400? Resolved?
  - **Response**:

    The excessive tube wear at the SONGS RSGs was very unusual phenomenon because it was induced by the in-plane fluid elastic instability (FEI) instead of out-of-plane. APR1400 SG will not have such in-plane FEI based on the two aspects, design feature & operating experience. The thermal-hydraulics analysis of SG secondary side is input to the FEI evaluation.

    As mentioned in the response to Question 9, EPRI's ATHOS computer program has been utilized to analyze the thermal-hydraulic conditions for all the OPR1000 as well as APR1400 SGs.

(Continued on next page)

Response to Chap. 5 Questions (9/15)

(Continued from previous page)

OPR1000 SGs have been operated in the Korean domestic nuclear power plants without experiencing such an abrupt in-plane FEI mechanism as that was observed in the U-bend region of SONGS RSGs.

The major design features of the tube and tube supports in the APR1400 and OPR1000 SGs U-bend region related to the FEI are identical to each other, such as the tube outer diameter, tube wall thickness, tube pitch and array, and assembled configuration of tubes and tube supports. About the geometry of tube bundle itself, the tube bundle is widened instead of lengthened to increase the heat transfer area from OPR1000 to APR1400 SG. Thus, the overall heights of OPR1000 and APR1400 SG tube bundles are similar, which make the secondary side thermal-hydraulic conditions to be similar.

The only difference between OPR1000 and APR1400 SG is the spacing of the tube supports. More lattice-bar grids (i.e., eggcrates) in the straight tubing section and vertical tube support bars in the U-bend region are installed in the APR1400 SG, thus the spacing of tube supports of APR1400 SG is substantially reduced compared to the OPR1000 SG, which results in the increase of tubing natural frequency.

Also, since the double 90^{o} bend tubing having the horizontally straight span in the U-bend region is applied for APR1400 and OPR1000 SGs, the horizontal strips (i.e., tie bars and lock bars) are inserted between the tubes to restrict vertical in-plane motion of the tubes (this is the key difference in APR1400/OPR1000 SG U-bend design with other 180^{o} U-bend design).

Response to Chap. 5 Questions (10/15)

(Continued from previous page)

In addition to the above design features and operating experience, the recent FEI experiments[1][2] provide the further justification on the soundness of the APR1400 SG against the in-plane FEI phenomenon.

SONGS RSGs uses the triangular array, but the APR1400 uses rotated square array.

For the square array, it is concluded that no instability is observed in the in-flow direction.

[1] Study on In-flow Fluidelastic Instability of Triangular Tube Arrays Subjected to Air Cross Flow, T. Nakamura et al., Journal of Pressure Vessel Technology, Vol.136, Oct. 2014.

[2] Investigation of In-flow Fluidelastic Instability of Square Tube Arrays Subjected to Air Cross Flow, T. Nakamura et al, Proceedings of the ASME 2015 Pressure Vessels and Piping Conference, Jul. 2015.

Response to Chap. 5 Questions (11/15)

- **Question 11:** Is there a manual valve at the suction of CS pump, otherwise one has to close valve 347 at the IRWST suction side to replace SCS pump with CS pump?
  - **Response**:

    The CS pump suction from the IRWST should be closed to perform Shutdown Cooling function using CS pump. The valve 347 should be closed because there is no manual valve in CS pump suction.

- **Question 12:** Are there any valves in SCS that do not fail as-is?
  - **Response**: All valves in SCS are Fail-As-Is.

- **Question 13:** Need drawing that shows every line connection to IRWST and location of spargers.
  - **Response**:

    The piping connected to the IRWST is shown in DCD Tier 2 Figure 6.8-3, and the POSRV and RCGVS spargers are shown in Figure 5.1.2-3 and Figure 5.4.12-1, respectively. The location of the POSRV and RCGVS spargers (plan view) and the typical header piping and spargers in the IRWST (section view) are shown in Figure 6.8-1 and Figure 6.8-7, respectively.

    Figure 5.1.2-3 and Figure 6.8-1 are revised and Figure 6.8-7 is added in the response to RAI 25-7844 Question 06.02.02-3 to provide the detailed information on the POSRV and RCGVS spargers.

(Continued on next page)

Response to Chap. 5 Questions (12/15)

(Continued from previous page)

Note)

Figure 6.8-3, In-containment Water Storage System Flow Diagram
Figure 5.1.2-3, Pressurizer and POSRV Flow Diagram
Figure 5.4.12-1, Reactor Coolant Gas Vent System Flow Diagram
Figure 6.8-1, IRWST and HVT Plan View
Figure 6.8-7, Typical Header Piping and Sparger in IRWST

- **Question 14:** RCGVS – Certain valve configurations could prevent pressurizer venting – do valves involved in venting have control room position indication?
  - **Response**:

    The solenoid-operated reactor coolant gas vent valves are provided in the RCGVS. Open/closed positions are indicated in the MCR and RSR.

    A manual pressurizer steam isolation valve is provided in the RCGVS and does not provide the position indication in the MCR and RSR. The valve is locked open and is controlled by the administrative procedure.

Response to Chap. 5 Questions (13/15)

- **Question 15:** Need AAC generator for 16 hours to operate RCGVS, but can't operate beyond 16 hours (something fails) – Does level 2 PRA ……
  - **Response**:

    In the APR1400 Level 2 PRA, the RCGVS is not modeled as a severe accident mitigation feature which needs to be operated during the severe accident. The APR1400 Level 2 PRA modeled that the primary system needs to be rapidly depressurized by operating the POSRVs with the flow change using 3way valves after the severe accident initiation. The RCS depressurization by operating the reactor gas vent flow paths during the severe accident is not considered in the APR1400 Level 2 PRA model. Hence, even if the RCGVS is unavailable beyond 16 hours in case of SBO accident, it does not impact on the APR1400 Level 2 PRA.

Response to Chap. 5 Questions (14/15)

- **Question 16:** Intersystem LOCA- Aux Prz spray line not included, why? Could be same as charging line?

  - **Response**:

    The scope of ISLOCA evaluation is the low-pressure systems (or subsystems) connected with the RCS. The auxiliary spray line is branched off the charging line downstream of the regenerative heat exchanger and designed to the pressure greater than or equal to the RCS design pressure. So, the auxiliary spray line is not included in the scope of ISLOCA evaluation.

Response to Chap. 5 Questions (15/15)

- **Question 17:** Each MSSV rated capacity appears to be of 5.3% full power, each POSRV can relieve 3.5% full power – Please confirm

  - **Response**:

    For MSSVs, 5.3% is a reasonable approximation.

    However, for POSRV, there is no such requirement for thermal power so that the POSRV capacity is set to prevent RCS overpressurization during transient without considering thermal power.

Response to Chap. 10 Questions (1/10)

- **Question 1:** ACRS cannot find any drawing that shows design principle how the MSIVs are closed hydraulically. How the MSIVs work? How many solenoids there are? Whether the solenoids are series or parallel? Whether MSIVs are designed to fail open or closed?
  - **Response**: Each MSIV actuator is designed to provide a fail-close mode upon loss of valve external motive power; i.e., air, hydraulic fluid, or electric power. All MSIVs are designed to close automatically to isolate the steam generator from the secondary side upon the receipt of the MSIS(Main Steam Isolation Signal) generated by any one of the following conditions:

    - Steam generator pressure low
    - Containment pressure high
    - Steam generator level high-high
    - Manual actuation from the MCR

    Each MSIV actuator control system is designed to provide valve operation on two independent control channels. The control channels are electrically and physically isolated from each other. The detail actuator control schematic is provided by the MSIV vendor.

Response to Chap. 10 Questions (2/10)

- **Question 2:** The steam relief capacity of each MSADV in Table 10.3.22-1 is $1.1x10^{6}$ lb/hr. The controllable capacity of each MSADV is 63,000 lb/hr, much less than the total relief capacity. What is the intent of that?
  - **Response**: MSADV is used for plant cooldown by manual operation after an accident or steam bypass control is not available. The capacity of 1,100,000 lb/hr is required for removing maximum decay heat after a reactor trip, and the capacity of 63,000 lb/hr is the minimum controlling capacity to remove RCP heat during hot standby condition.

Response to Chap. 10 Questions (3/10)

- **Question 3:** What is the emergency blowdown function? What is the criteria for opening the emergency blowdown line? What is the criteria for resetting the steam generator blowdown isolation signals? What is the criteria for terminating the emergency blowdown?
  - **Response**: When one or more SG tubes are ruptured (EOP : Emergency Operating Procedure), Emergency Blowdown System is actuated manually by an operator to reduce the SG water level by opening the isolation valves in both blowdown paths. The blowdown control valves are automatically closed when the SG blowdown flash tank water level reaches the high level setpoint. During normal operation (NOP : Normal Operating Procedure), the isolation valves are maintained in the closed position.

    There are safety-related narrow range and wide range SG water levels. The wide range water level is used to initiate a reactor trip and the auxiliary feedwater system at the low level setpoint, and the narrow range water level is used to initiate a reactor trip and the Main Steam Isolation Signal (MSIS) at the high water level.

    Thus, the low water level alarm comes from the wide range water level instrumentation, and the high water level alarm comes from the narrow range water level instrumentation. If a SGTR occurs, high level alarm, reactor trip and MSIS will be generated by narrow range water level instrumentation.

Response to Chap. 10 Questions (4/10)

- **Question 4:** Figure 10.4.9-1(1 of 3 and 2 of 3) in the DCD shows several different line sizes from the auxiliary feedwater storage tanks to the auxiliary feedwater pump suctions.
  - **Response**: There were editorial errors in the figure 10.4.9-1(1 of 3 and 2 of 3). The auxiliary feedwater pump suction line size branched from 12 inch common line of each auxiliary feedwater storage tank is 8 inch not 6 inch or 10 inch. The different line sizes on figure 10.4.9-1 (1 of 3 and 2 of 3) in the DCD will be revised from 6 inch and 10 inch to 8 inch.

Response to Chap. 10 Questions (5/10)

➢ **Question 5:** Turbine-driven AFW pump lines are supplied with battery-backed Class 1E power supplies for 16 hours. Trains C and D of the batteries are 16 hours. Turbine-driven AFW train C, modulating valve 36, which is supplied from electric power train B with 8 hour battery. Turbine-driven AFW train D, modulating valve 37, which is supplied from electric power train A with 8 hour battery. Why the power supplies for the modulating valves (V037, V036) of turbine-driven AFW trains are from trains A and B rather than trains D and C?

- **Response**: Turbine-driven AFW trains have two methods to control the steam generator level, one is the AFW modulating valve powered from trains A and B with 8-hour battery, the other is the AFW isolation valves powered from trains C and D with 16-hour battery. Also, the AFW pump turbines are supplied by the power from trains C and D. In the case of the station black out, the AFW modulation valves, which are fail open type valves, are opened and the AFW isolation valves are operated to control the steam generator level. Therefore, in the case of the station black out the turbine-driven AFW trains can supply the water to steam generator by controlling the AFW isolation valves.

Response to Chap. 10 Questions (6/10)

- **Question 6:** Have you done an analysis of missiles from the Turbine-driven AFW pump itself?

  Response: The turbine-driven AFW pump has the emergency trip systems, mechanical and electrical trip, to prevent the missile due to the turbine over-speed. The vendor of the turbine/motor-driven AFW pumps will provide the missile analysis report to demonstrate that the postulated missiles for rotating parts of equipment would not penetrate through its casing or housing at 120% over-speed condition.

  Also, each AFW pump is located in physically separated room. The common discharge line of AFW pump is connected inside containment not AFW pump room. The common suction line of AFW pump is branched at the AFW storage tank room.

  Therefore, there is no adverse effect of the AFW system due to the missile of AFW pumps.

Response to Chap. 10 Questions (7/10)

- **Question 7:** The isolation valves are closed automatically by an ESFAS signal at a steam generator level higher than normal operating level. That is for the auxiliary feedwater isolation. What is the setpoint to close the auxiliary feedwater isolation valve?
  - **Response**: AFAS (one of ESFAS signal) is set or reset according to the SG water level (cycling operation). When SG water level reaches to the reset point (40% WR), AFAS is reset and the AFW isolation valves are automatically closed.
- **Question 8:** DCD Figure 10.4.9-1 shows the auxiliary feedwater storage tanks with the raw water makeup supply from the raw water storage tank. When is the raw water used?
  - **Response**: The AFW system has two 100% capacity auxiliary feedwater storage tanks (AFWSTs). The AFWSTs are supplied with the makeup water from the demineralized water storage tank. Also, a non-safety-related backup water source is available from the condensate storage tanks. When the condensate storage tanks are unavailable, the raw water storage tank can supply the backup makeup to the AFW system. The total volume of raw water tank is 2,640,000 gal (2x1,320,000) for BDBEE and specified in IBR TeR for Fukushima accident, APR1400-E-P-NR-14005-P.

Response to Chap. 10 Questions (8/10)

- **Question 9:** The main steam isolation signal closes the main steam isolation valves for both steam generators. If the high level of only one steam generator, all main feedwater to both steam generators is isolated. That is an unusual design. If a steam generator level is high, the main feedwater to that steam generator is isolated and the other steam generator will retain main feedwater. This is obviously an active decision. And I would like to know what analyses were done to justify that decision.
  - **Response**: MSIS is generated by high SG water level, low SG pressure, and high containment pressure. MSIS is to isolate SG, and isolation of SG is closing all the isolation valves connected to secondary side of SG including MSIV and MFIV. MSIS and associated accidents are as follows;

    SGTR, High SG water level, MSLB, FWLB : low SG pressure

    LOCA, MSLB, FWLB : high containment pressure

    Selective isolation of SG or selective valve isolation requires very complicated control logic design.

    APR1400 ESFAS design prefers simplification of signal generation and ESF actuation logic, and the accident analysis acceptance criteria are met for those accidents. Main feedwater is not safety related and retaining main feedwater is not necessary during accident condition. Main feedwater pumps are tripped with MSIS.

Response to Chap. 10 Questions (9/10)

- **Question 10:** The nominal grade level of the turbine building is 100 feet. The maximum flood height was determined to be 104 feet above the grade level. There is a non-safety-related switchgear room at the elevation below grade, subsequently below grade. Are the doors to that switchgear room watertight? There are non-safety-related battery rooms at grade level. Are the watertight doors for the battery rooms?
  - **Response**: For the flood protection of switchgear room, the general access door is installed on the flood level (El. 104 feet) in accordance with KURD Chapter 6, Section 2.3.2.3 to enhance the survivability of non-safety related electrical equipment. Therefore the watertight door is not applied. The battery room (non-safety related), however, is not required to be protected from flood.

Response to Chap. 10 Questions (10/10)

- **Question 11:** Table 10.4.8-3 is included the codes and standards. Why is there not a table in each section for a system that captures all the codes and standards for that system? Examples the main steam system, the condensate system.
  - **Response**: Since the steam generator blowdown system conforms to RG 1.143 Rev.2, which lists the required codes and standards, Table 10.4.8-3 of DCD Tier 2 summarized its conformance evaluation listing the applicable codes and standards for each components. Analogously, the liquid waste management system, gaseous waste management system, and solid waste management system conform to RG 1.143 and their conformance of codes and standards are listed in Tables 11.2-7, 11.3-2, and 11.4-5, respectively. The other systems in Chapter 10 of DCD Tier 2 are listed in DCD Tier 2, Table 3.2-1.

Response to Chap. 11 Questions (1/4)

- **Question 1:** Where is the space in the certified design compound building for a laundry if I wanted to put in a laundry?
  - **Response**: Spaces for a laundry are available in the Compound Building, elevation 63'-0". On this floor, there are detergent waste tank room, contaminated clothing storage room, and non-contaminated clothing storage room.

    The area of each contaminated clothing storage room and non-contaminated clothing storage room is about 792 ft^2 (22' X 36'). These storage rooms can be used to install washing and drying machines if necessary. In Korean NPPs, which typically treat laundry waste on-site, these rooms are used for this purpose.

    Two detergent waste tanks, 6,000 gallon each, are available to collect detergent liquid waste for treatment and release. The capacity of each tank exceeds the requirement of ANSI/ANS 55.6, Table 7 for daily maximum generation of laundry waste of 2,000 gallons.

Response to Chap. 11 Questions (2/4)

- **Question 2:** If I have a high radiation on a gaseous discharge and valve 008 does not close, how do I stop the gaseous discharge? When do I open valve 1015? When during normal or abnormal operations would that valve be open?
  - **Response**: Since the GRS is based on continuous operation, the isolation is not normally used. Gaseous effluents from the GRS is mixed with the GRS cubicle ventilation flow and then filtered by normal exhaust ACU to the environment. In the event of high radiation with the valve 008 not closed tight, the two valves (valves 1013 and 1014) located at both sides of the valve 008 are to be closed for maintenance of valve 008. Valve 1015 is opened for vent flow until the valve 008 is fixed. It is noted that the normal GRS cubicle exhaust is routed to the CPB ventilation system and is treated by the normal ventilation ACU; or diverted to the emergency exhaust ACU in the condition of high radiation. Radiation monitors located at GRS and HVAC system continue to detect the flow that contains radionuclides. In addition, the vendor for GRS package is required to provide another isolation valve in the effluent discharge line. This isolation valve can be closed remotely when the isolation valve V008 fails to close. Therefore, it is considered that the gaseous effluent to environment is monitored and controlled at all times during normal operation. ***(Continued on next page)***

Response to Chap. 11 Questions (3/4)

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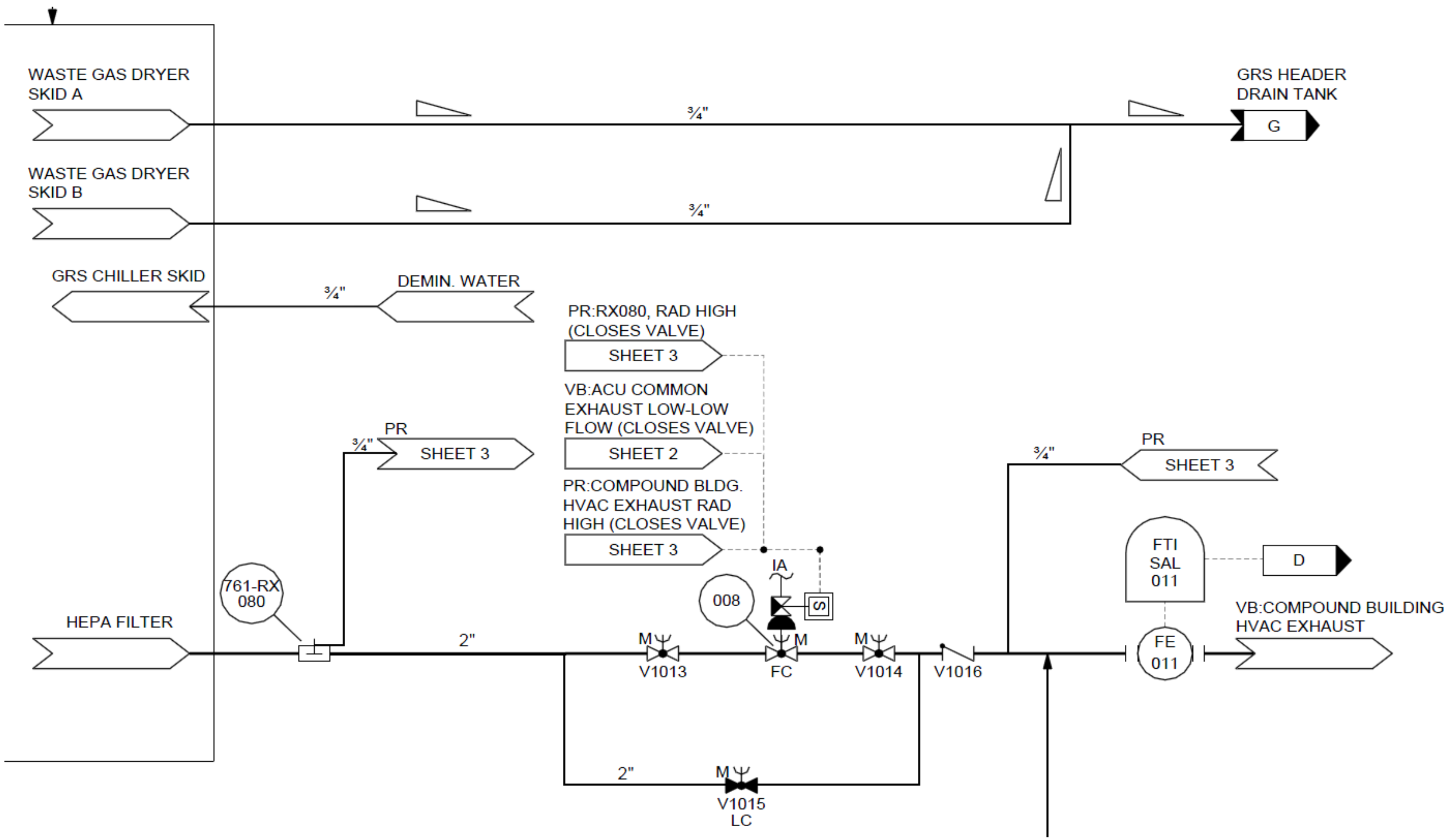

Figure - Flow diagram for gaseous radwaste system discharge

NON-PROPRIETARY

Response to Chap. 11 Questions (4/4)

- **Question 3:** Do you have any operating experience to confirm the fact that you generate less than the amounts of spent resin that you are assuming in your design?
  - **Response**: The Spent Resin Long-term Storage Tank (SRLST) is sized for storage of up to ten years of spent resin. The table below shows that the operating experience of spent resin generation in Korean NPPs for recent 10 years. It also provides the volume ratio of filled spent resin to APR1400 SRLST design capacity. The spent resin is stored up to about 50% of SRLST design capacity considering the resin sluice water volume. Since the filled volume ratio in the table are much less than 0.5, it is confirmed that the SRLST has sufficient capacity of spent resin storage for 10 years.

(Unit: L)

Plant	‘06	‘07	‘08	‘09	‘10	‘11	‘12	‘13	‘14	‘15	Total	Ratio
Hanul 3		1,800	1,800	1,800		2,700	2,000		2,000		12,100	**0.13**
Hanul 4	2,700	2,700		3,600	1,800	2,700				3,000	16,500	**0.18**
Hanul 5	4,200		1,050	2,100	2,100	2,100	1,050	2,100	2,100		16,800	**0.19**
Hanul 6	1,050	2,100	2,100		2,100	2,100	3,150		2,100	2,100	16,800	**0.19**
Hanbit 3	3,000	3,000	3,000		3,000	1,000	2,000	1,000	2,000	2,000	20,000	**0.22**
Hanbit 4		3,000	4,000	2,000	1,000	1,000	2,000	3,000		2,000	18,000	**0.2**
Hanbit 5	1,000		2,000	1,000	1,000		1,000	2,000		2,000	10,000	**0.11**
Hanbit 6	2,000	1,000	1,000		1,000	1,000	1,000		2,000	1,000	10,000	**0.11**