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12 proceeding of the United States Nuclear Regulatory
13 Commission Advisory Committee on Reactor Safeguards,
14 as reported herein, is a record of the discussions
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16
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18 corrected, and edited, and it may contain
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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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636TH MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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THURSDAY

SEPTEMBER 8, 2016

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ROCKVILLE, MARYLAND

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The Advisory Committee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:31 a.m., Dennis Bley, Chairman, presiding.

COMMITTEE MEMBERS:

DENNIS C. BLEY, Chairman

MICHAEL L. CORRADINI, Vice Chairman

PETER RICCARDELLA, Member-at-Large

RONALD G. BALLINGER, Member

CHARLES H. BROWN, JR., Member

MARGARET CHU, Member

WALTER L. KIRCHNER, Member

JOSE A. MARCH-LEUBA, Member

DANA A. POWERS, Member

HAROLD B. RAY, Member

JOY L. REMPE, Member

GORDON R. SKILLMAN, Member

JOHN W. STETKAR, Member

MATTHEW W. SUNSERI, Member

DESIGNATED FEDERAL OFFICIAL:

PETER WEN

KENT HOWARD

ALSO PRESENT:

ROSSNYEV ALVARADO, NRR

BENJAMIN BEASLEY, DLR

RANDY BREYMAIER, DTE

MANNY COMAR, NRO

YOIRA DIAZ-SANABRIA, DLR

STEVE FRANZONE, FP&L

LYNN GOODMAN, DTE

ZACH HARPER, Westinghouse

ALLEN HISER, DLR

PAUL JACOBS, FP&L

LOIS JAMES, NRR

JOHN LUBINSKI, NRR

WILLIAM MAHER, FP&L

ROBERT MALIVA, WSP Parsons Brinckerhoff

JIM MARONE, Bechtel

DAVID MCNABB, MHC

JEFFERY MITCHELL, NRR

BRUCE MUSICO, NSIR

RICHARD ORTHEN, FP&L

MALCOLM PATTERSON, NRO

LARRY PETERSON, DTE

KEITH POLSON, DTE

MARY RICHMOND, Bechtel

KENNETH SCHRADER, PG&E

BALWANT SINGAL, NRR

RICHARD STATTEL, NRR

RAO TAMMARA, NRO

JOHN TIBAI, DTE

ANDREA D. VEIL, Executive Director, ACRS

MICHAEL WATERS, NRR

*Present via telephone

A G E N D A

Opening Remarks.....5

Turkey Point Combined License Application.....6

Review of Safety Evaluation Associated with

Diablo Canyon Power Plant Units 1 and 2 Digital

Replacement of Process Protection System.....86

Fermi 2 License Renewal Application.....145

Adjourn.....171

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

2 8:31 a.m.

3 CHAIRMAN BLEY: The meeting will now come

4 to order. This is the first day of the 636th meeting

5 of the Advisory Committee on Reactor Safeguards.

6 During today's meeting, the Committee will

7 consider the following: Turkey Point Combined License

8 Application, Review of Safety Evaluation Associated

9 with the Diablo Canyon Power Plants Unit 1 and 2 digital

10 replacement process protection system, Fermi 2 License

11 Renewal, and preparation of ACRS reports.

12 The meeting is being conducted in

13 accordance with the provisions of the Federal Advisory

14 Committee Act, and Mr. Peter Wen is the Designated

15 Federal Official for the initial portion of this

16 meeting. We have received no written comments or

17 requests to make oral statements for members of the

18 public regarding today's sessions.

19 There will be a phone bridge line. To

20 preclude interruption of the meeting, the phone will

21 be placed in the listen-in mode during the

22 presentations and Committee discussion. A transcript

23 of portions of the meeting is being kept, it is

24 requested that speakers use one of the microphones,

25 identify themselves and speak with sufficient clarity

1 and volume so that they can be readily heard.
2 I want to make you aware that this meeting
3 is also being webcast, with the ability to view our
4 presentation slides on the web. Also, the quality of
5 audio is much better on the website than on the phone
6 line. Those of you who are on the bridge line who may
7 want to do that can connect through the NRC's public
8 meeting website and click on the link. It should work.
9 If it doesn't, please call our office.
10 At this time, I'll turn the meeting over
11 to Member Harold Ray for the first item of business.
12 Harold.
13 MEMBER RAY: Thank you, Mr. Chairman.
14 We'll start today with the review of the combined
15 license application from FPL for the Turkey Points
16 Units 6 and 7. They're Westinghouse AP1000 certified
17 designs, and the COLA is based, of course, as others
18 that we've looked at, on the Design Center Review
19 process that we're familiar with, at which we only
20 looked during the Subcommittee meeting on August 18th
21 and 19th at those things which were site-specific and
22 particular to the Turkey Point site.
23 I believe it's well known that there are
24 existing units there already, Westinghouse PWR units.
25 So this would be in addition to that site of nuclear

1 units. There are also fossil plants at the site. The
2 two day meeting, fortunately and I much appreciate
3 this, that we had at subcommittee level in August was
4 attended by all members except Matt, who was not
5 available, at least for most of the meeting.
6 So the agenda today is going to focus
7 pretty specifically on questions and unresolved
8 matters that were left on the table at that time. There
9 will be an overview of course, but the effort will be
10 devoted largely to responding to members' questions and
11 other issues that weren't fully resolved at that time.
12 I appreciate that the applicant has I
13 believe done a thorough job in looking for those kinds
14 of things. There are others, of course, and members
15 will raise them at this time as well. But we will be
16 going through item by item things that were discussed
17 at the subcommittee level and not perhaps fully
18 resolved.
19 We have two hours for this time, which is
20 not a lot given many things that are on the table here.
21 But I believe it will be adequate for us to get through
22 them all. But to get on with matters, I'll turn it over
23 Mr. Comar of the staff for any comments that he has.
24 MR. COMAR: Good morning. I'm Manny
25 Comar, the lead project manager for Turkey Point Units

6 and 7 combined license application. I want to thank the chairman and members of the committee to give us this opportunity to present the key topics of the site-specific review of the Turkey Point combined license application.

The staff intends only to brief site-specific topics based on the feedback that we received from the subcommittee meeting, and I have Jennifer Dixon-Herrity, my branch chief here, supporting this review also, and in accordance with the agenda I would like to ask the applicant to start their presentation. Thank you.

MEMBER RAY: Thank you Manny, and the applicant has the floor.

MR. MAHER: While all of my people get set up in the front, I'll start off. Good morning, Mr. Chairman and the committee. Thank you very much for having us here. My name is Bill Maher. I'm senior director of New Nuclear at Florida Power and Light. Today we plan to highlight certain aspects of the Turkey Point COL application based on interest from the subcommittee.

I want to repeat what I said at the subcommittee opening, in that we appreciate the significant efforts that has gone into the process by

1 both the NRC staff and the ACRS. Our team is ready to
2 present the Turkey Point COL information, so that you
3 will be able to find reasonable assurance that Turkey
4 Point can be built and operated without undue risk to
5 the health and safety of the public, and in an
6 environmentally responsible manner.
7 Again, we appreciate the significant
8 effort that the NRC staff and the ACRS has put into
9 reviewing the Turkey Point COLA. The staff's review
10 has been extensive and thorough, and accomplished with
11 the highest degree of professionalism. We are ready
12 to discuss the Turkey Point COLA at this point, and I'll
13 turn it over to Steve after a few transcript corrections
14 from the subcommittee.
15 In the transcript for the Subcommittee, it
16 was identified that I was with Florida Power. I'm with
17 Florida Power and Light. Florida Power is a previous
18 incarnation of Duke Energy Florida. So I just wanted
19 to be correct on this, for those of us who remember that.
20 Also in the transcripts, the COD dates are
21 listed as 28 and 29. It's 27 and 28, so just be correct
22 on that. Also at the end of the subcommittee, there
23 was some discussion on FLEX strategies, and what we
24 would do as part of Phase 2. I said I would get back
25 to the Committee as far as what those FLEX strategies

1 were.

2 What is in the application is within Phase

3 1 and Phase 2 FLEX strategies. Since the AP1000 is a

4 72 hour coping plant, there are no actions to be taken,

5 and any of the actions to be taken start at Phase 3.

6 If you wanted to have any more discussion on details

7 with respect to that, than it would either be

8 proprietary or SUNSI, depending on what types of

9 details you want to get into. So I'll just be correct

10 on that. That's all I had, unless there's questions.

11 Okay, Steve.

12 MR. FRANZONE: Good morning Chairman and

13 members of the Advisory Committee on Reactor

14 Safeguards. My name is Steve Franzone. I'm the

15 Florida Power and Light licensing manager for the New

16 Nuclear Projects. In that role, I'm responsible for

17 the licensing of Turkey Points Units 6 and 7. This

18 slide provides a listing of the sections we'll focus

19 on this morning. We have a later slide that gets a

20 little bit more on level of detail on each section.

21 Next slide, okay. I'd like to give the

22 Committee a brief overview of Turkey Point's 6 and 7

23 site. This is a map of South Florida area, and it shows

24 a Turkey Point location relative to Miami. The site

25 is located in southeastern Miami-Dade County,

1 approximately 25 miles south of the city. On the east
2 side of the plant are Biscayne Bay and Biscayne National
3 Park.
4 To the west of the plant are the two closest
5 cities, which are Homestead and Florida City, and just
6 past those cities you'll find Everglades National Park.
7 The closest primary public roads are the U.S. Highway
8 1 and the Homestead extension of the Florida Turnpike.
9 Okay, next slide. The site is
10 approximately a 218 acre island within the industrial
11 wastewater facility. It's also known as the cooling
12 canals. The finished grade of the nuclear island will
13 be approximately 25.5 feet due to storm surge and wave
14 runup.
15 On the figure, you can see the Homestead
16 Air Reserve Base is northwest of the site, just outside
17 the five mile radius. You can see where the little air
18 runway is. So the primary cooling water source is
19 reclaimed water received from Miami-Dade County. The
20 reclaimed water is first sent to an onsite treatment
21 facility, which is shown as the small blue rectangle
22 northwest of the site.
23 Okay, thanks. On this slide, the south
24 side of the site is at the bottom of the slide, okay.
25 After onsite processing, the reclaimed water is sent

1 to the makeup water reservoir. This reservoir
2 contains approximately a three-day supply of cooling
3 water for the plants. Just north of the reservoir, the
4 two AP1000 units located side by side.
5 The little orange boxes with a dot in the
6 middle are the underground injection control wells that
7 are part of the deep well injection system used to
8 effluent and blowdown disposal. We will have 12 deep
9 wells with one monitoring well for each pair of deep
10 wells. That's why you see the little dot in the middle.
11 Okay, and then just a little north, further
12 north of the units you'll see the Clear Sky Substation
13 along with parking and other facilities.
14 Next slide, please. Several issues have
15 caused our application to change. Basically, we
16 followed the standard AP1000 responses, except in the
17 area of the CES, where we had to do some site-specific
18 sensitivity studies, which were all found acceptable.
19 I was going to go to the next slide, unless there's
20 questions here.
21 Okay. Here are the specific areas we'll
22 focus on during the remainder of the presentation.
23 Section 2.1, you'll see population density. 2.4, sea
24 level rise. 11.2, we have some deep well injection
25 modeling and release monitoring information we're

1 going to present.

2 Emergency planning, we're going to focus

3 really on the tech support center instrumentation

4 power, and then last on Chapter 19 we're going to talk

5 about the aviation accident core damage frequency. At

6 this point, our next speaker is Rick Orthen, the

7 licensing engineer for the project.

8 MR. ORTHEN: Good morning committee

9 members, chairman. My name's Richard Orthen with

10 Florida Power and Light licensing. Today, I'm going

11 to be talking about the Section 2.1, geography and

12 demography, specifically population considerations.

13 There are three population considerations which exist

14 under 10 C.F.R. 100.21 requirements.

15 Those are the exclusion area, EA controls,

16 low population zone, LPZ designation, the distance to

17 the nearest densely populated center and population

18 density. Turkey Points meets EA, LPZ and densely

19 populated center distance, 10 C.F.R. 100.21

20 requirements. Regulatory guidance --

21 MEMBER RAY: Excuse me. Before you go

22 further, there is one thing in looking at the

23 subcommittee meeting that I don't believe we ask about,

24 and it doesn't contradict what's said there. But in

25 talking about site characteristics with respect to

1 AP1000 site parameters, it was stated that the
2 population distribution exclusion area, exclusion
3 area, wasn't -- for the AP1000 wasn't satisfied by this
4 site. I don't remember us discussing that.
5 MR. ORTHEN: Mary?
6 MEMBER RAY: It's Slide 20 of the
7 subcommittee slide presentation.
8 MS. RICHMOND: Hi, Mary Richmond with
9 Bechtel. I believe that was in reference to the half
10 mile exclusion area boundary distance. We discussed
11 it. It was in a slide from the ACRS subcommittee
12 meeting. In all the free sectors, it was not met.
13 However, the Chi over Q values and the doses were met.
14 MEMBER RAY: Okay. Well, I just wanted to
15 distinguish it from what Richard was talking about
16 here, in that it's an AP1000 DCD site parameter that
17 we're talking about in that case. Here, we're talking
18 about the compliance with the regulatory requirements.
19 MR. ORTHEN: You're correct.
20 Specifically, the site characteristic Chi over Q at the
21 EAB meet the DCD parameter values. So that's --
22 MEMBER RAY: Which probably means the wind
23 blows a lot at the site.
24 MR. ORTHEN: Well, it's the relative
25 diffusion parameters, sir. Dispersion parameter are

1 below --

2 MEMBER RAY: Yes, I understand.

3 MR. ORTHEN: Does that answer your

4 question? Okay, continuing on. Regulatory guide

5 4.7, Revision 2 guidance was used to determine if Turkey

6 Point is an area of low density. Turkey Point meets

7 the area of low density guidance between 1 and 5 miles.

8 Turkey Points exceeds 500 persons per square mile

9 between 5 and 20 miles. Twenty miles is the outer range

10 of the regulatory guidance.

11 These population density exceedances

12 between 5 and 20 miles are not considered well in excess

13 of the 500 person per square mile criterion in the

14 regulatory guide. Regarding 10 C.F.R. Section

15 100.21(g) and 100.21(h), that physical site

16 characteristics not pose a significant impediment to

17 the development of emergency plans, FPL demonstrated

18 acceptable measures for public radiological safety

19 when assessing accidents at the Turkey Point site.

20 Next slide, please. In accordance with

21 regulatory guide 4.7 site safety considerations and

22 Section 100.21(h) requirements, the principle factors

23 influencing FPL's selection of the Turkey Point site

24 over other alternative sites with lower nearby

25 population densities include several unique, safety,

1 economic, reliability and environmental attribute
2 advantages that would not be realized if the plant were
3 located elsewhere.
4 Those factors include the ability to
5 balance generation and load in South Florida with
6 Miami, unique cooling water supply source, reclaimed
7 water, land availability, the fact that there's
8 existing nuclear power plant infrastructure in place
9 at the Turkey Point site, and there's also existing
10 emergency planning infrastructure in place.
11 Then from Section 5.11.2.5 of the draft
12 environmental impact statement, the 50 mile population
13 dose risk impact from Units 6 or 7 severe accidents,
14 2.7 times 10 to the minus 1 person REM per reactor year,
15 was established as supporting a small impact
16 determination in the draft EIS.
17 10 C.F.R. 100 analysis concluded that no
18 alternative site was environmentally preferable.
19 MEMBER RAY: Thank you. I think that
20 succinctly states what we discussed at greater length
21 in subcommittee, so thank you.
22 MR. FRANZONE: Now we'll switch. All
23 right, next slide. Okay. So now we're going to talk
24 about sea level rise. We can go up to the next slide.
25 Okay. General Design Criteria 2 provides the design

1 basis for protection against natural phenomena. The
2 Reg Guide 1.59 provides -- discusses acceptable methods
3 for the applicants to meet this GDC 2.
4 In addition, Reg Guide 1.206 states that
5 combined license applicants referencing a certified
6 design include the antecedent water level, which is the
7 10 percent exceedance high tide, including initial rise
8 for coastal locations.
9 Also, the determination of petroleum storm
10 surge or seiche, a detailed description of methods and
11 models used and the results of the computation of the
12 probable maximum surge hydrograph. Okay, so this just
13 basically reviews the requirements that we used.
14 Okay, next slide. So in addition to the
15 ten percent exceedance high level spring tide and
16 initial rise, FPL considered the long term trend
17 observed in the tide gauge measurements to account for
18 expected sea level rise for a period consistent with
19 the plant design objective of 60 years for AP1000s.
20 The station nearest to Units 6 and 7, where
21 long term sea level, long term permanent sea level rise
22 is available and is the Miami Beach station 8723170
23 station located. If we could go back to the first
24 slide, talks about the whole. It shows the -- I just
25 want to show them basically where that's at relative

1 to the site. One more, one more. Okay, right here.
2 All right. Yes. So basically we're
3 talking right in this area right here, where the little
4 cursor is.
5 VICE CHAIR CORRADINI: That's the closest
6 observation point?
7 MR. FRANZONE: Right. That's Miami or
8 the Miami Beach Florida station, okay. However, that
9 station is no longer active. The long term sea level
10 rise train at Miami Beach, Florida estimated, based on
11 data from 1931 to 1981, which is when it became
12 deactive, is .78 foot per century. Accordingly, a
13 nominal long term sea level adjustment of one foot is
14 applied to the ten percent high tide level resulting
15 in an antecedent water level of 3.6 feet NAVD 88.
16 It's the 2.6 for the ten percent high level
17 tide plus the foot per sea level rise.
18 MEMBER RAY: Would you, because it appears
19 in many places, the NAVD 88. Just say what it is.
20 MR. ORTHEN: North American -- this is Ray
21 Orthen.
22 MR. FRANZONE: Vertical Datum, yes.
23 MEMBER RAY: It's repeated time after time
24 without being defined, so it took me a while to dig out
25 what the heck it was.

1 MR. FRANZONE: Okay, yes. Okay. North
2 American Vertum Datum '88, 1988. And this represents,
3 this initial 3.6 level rise is used as the base
4 condition. It's the initial water level in the SLOSH
5 model simulations.
6 In addition or in response to request for
7 additional information from the NRC staff, FPL also
8 investigated the Key West station located farther away
9 with more recent data using a linear trend model to
10 historical monthly mean sea levels from January 1941
11 to November 2010 at Key West Florida Tide Station.
12 That's Station 8724580.
13 The linear trend leads to a projected
14 increase of .69 feet in 100 years. It also should be
15 noted at Key West is approximately 110 miles southwest
16 of the site. Here, you see this table on here basically
17 is taken right from the RAI response, and it shows one
18 of the questions in the RAI was it's non-linear, doing
19 a second order trend analysis versus the linear
20 extrapolation, if there's some difference there.
21 On the left side, the linear
22 extrapolation, you can see Key West .69. That's up to
23 2010. If you look at the same data for Key West 3181,
24 it's .56. Of course in Miami Beach we did, and then
25 we did a hybrid Miami Beach data and Key West data and

1 that came out to about .77. The non-linear was all
2 over. It had negative numbers, positive numbers. So
3 we basically concluded that wasn't acceptable to use.
4 MEMBER RAY: But the key point was that it
5 was all based on historical data?
6 MR. FRANZONE: Correct.
7 MEMBER RAY: Okay. There are different
8 ways from extrapolating from it, but it's historical
9 data you used and that's -- and then you increased it
10 from .78 to 1?
11 MR. FRANZONE: Correct.
12 MEMBER RICCARDELLA: And of course the
13 real question is whether historical data has any
14 meaning in terms of extrapolating forward, given the
15 climate change considerations. That's the question
16 that's been raised, I think, that we're going to have
17 to address.
18 MEMBER RAY: Well, but the application is
19 based on historical data and uses the regulatory
20 guidance.
21 MEMBER RICCARDELLA: I understand that.
22 MEMBER STETKAR: Let me put something on
23 the record, because it's something that the -- has been
24 distributed to the Committee, and I know I've taken it
25 into consideration. There's a report in 2015 by the

1 Southeast Florida Regional Climate Change Control
2 Compact on projected sea level rises out through the
3 year 2100.
4 It projects sea level rises much in excess
5 of those projected by Turkey Point. I just want to put
6 that on the record. I'm not necessarily giving it any
7 more or less credibility than the projections we see
8 in front of us. I think linear projections on
9 historical data dating back to 1941 are silly at best,
10 but apparently they followed the rules.
11 What we've discovered recently on external
12 events, environmental-related events, seismic events,
13 high winds, external flooding, is that reliance on
14 regulatory bases that were derived back when people
15 didn't think about these things very carefully.
16 Often, it went to optimistic assessments.
17 The change of regulatory guidance
18 regarding high winds, relative to that for external
19 flooding. We have a little flood going on over here
20 that we need to take care of.
21 MEMBER RAY: John.
22 MEMBER STETKAR: My question going
23 forward how do we have assurance that Turkey Point will
24 keep track of this, because everybody says well, it's
25 a slowly developing phenomena. We've raised questions

1 as a Committee about this in the past regarding
2 currently operating sites, which are not required to
3 periodically reexamine external hazards. They're
4 basically grandfathered into the license on the day
5 that they were -- that the plant was built.
6 So people don't have to look in a
7 regulatory sense at changes in environment. They
8 don't have to look at changes in local industrial
9 facilities and things like that. So what assurance do
10 we have that Turkey Point will monitor the rate of
11 change going forward?
12 Are you going to periodically reexamine
13 every five or ten years whether or not your linear
14 projections remain accurate over the 60 years of the
15 plant life, once it's eventually constructed, which
16 could be several years from now? Do you have a license
17 commitment to do that?
18 MEMBER RAY: Well, at least some of us have
19 considered that we might comment in that direction.
20 MEMBER STETKAR: I'm asking -- no, I'm
21 asking that.
22 MEMBER RAY: I understand, and I would ask
23 them to respond to it. But while they're thinking
24 about the response, let me say two other things. One,
25 this is just guidance that says use historical data.

1 So it's not something that isn't subject to some other
2 alternative.
3 In particular, the staff and the advance
4 safety evaluation did raise the point that you're
5 discussing John, which is that projections depart from
6 extrapolations from historical data, and they were very
7 specific in the advance safety evaluation on that
8 point. So it has -- it is a question that's been
9 raised, which the applicant responded to at that time
10 as the ASE describes it.
11 But you've asked again about the
12 monitoring going forward, so we should get an answer.
13 MR. FRANZONE: Yes. We don't have any
14 license condition or commitment to do that that I know
15 of right now. Here you see our actual grade of 25 or
16 26 feet, the plant design is 26 feet. It shows you the
17 additional margin that we actually have in the
18 analysis.
19 The green is what we can call -- we'll call
20 margin, and there's three groups of margin. The one
21 is in the calculation of the ten percent exceedance.
22 We actually added and it ends up being a 1.2 feet, based
23 on if you looked at just historical data, which we are
24 allowed to do by regulation.
25 MEMBER STETKAR: I understand. By the

way, I'm not arguing that you didn't follow the rules. You followed the rules and that's not --

MR. FRANZONE: We did more than follow the rules, I think, because we added the margin that we're showing here. By the rules, we could have just left it at the 2.6 NAVD, you know, NAV88 value.

What we did was we went back to the reg guide and used a list of more conservative value at the Reg Guide, which is we got us up to the 2.6 plus the one foot for sea level rise. We're not even calling the margin. As you see, that's left out of the margin equation.

The next margin, what we consider as margin in the SLOSH model itself, the 20 percent basically for soft model uncertainty, when you look at Turkey Point site and we compare it to actual events, the SLOSH model basically was very close for Andrew and for another hurricane, I think '45 hurricane that we used.

And then the final margin, if you will, is the plant grade margin of 1.2 feet. When you calculated, add everything up, then we added a little bit extra past that, the 1.2 feet. So we consider that all margin. So if you look at surrounding government agencies, what they're looking at for their -- a sea level rise is well below, I mean like ten feet below

1 this value of 26 feet they're using in the base.
2 MEMBER STETKAR: And I'm not arguing there
3 is substantial uncertainty in various predictions of
4 sea level rise over the next, you know, five or six or
5 eight or ten decades.
6 There, depending on what reference you
7 look at, you can get a widely divergent set of
8 estimates, and that's just part of the uncertainty we
9 have in terms of environmental effects and climate
10 change. That all could change depending on, you know,
11 various factors.
12 MR. FRANZONE: Right, and I agree
13 completely.
14 MEMBER STETKAR: And I'm not arguing about
15 the fact that there's uncertainty. I'm not arguing
16 about the analyses that you have done. I'm asking
17 about the fact that as you build and operate this plant
18 over the next -- I don't know when your construction
19 date is, but 60 years after you actually start
20 operation, how do we have assurance that we have some
21 early warning that if you need to extend the height of
22 that retaining wall by some amount, we have enough
23 forewarning to do that, to plan to do that in a measured
24 way?
25 MR. FRANZONE: Right. But the point of my

1 comment wasn't to comment on what they've done or
2 assume, but it basically is as the government agencies
3 and the local governments follow this issue over the
4 next 60, 80, 100 years whatever it's going to be, we're
5 intimately involved with the local government. If
6 they start taking measures that's -- to indicate that
7 there is some reason we're going to have to impact the
8 plant, then we would follow that.
9 But at this point, they're not taking those
10 measures, right. There's a lot of discussion, but none
11 of the government, local governments has taken any
12 great measures as far as combating sea level rise.
13 MR. MAHER: This is Bill Maher, Florida
14 Power and Light. You bring up a good issue and a good
15 point probably from a safety standpoint. I will say
16 that Florida Power and Light operates its nuclear
17 plants. We strive to operate them in a very manner in
18 accordance with the regulations.
19 As you bring up, there are a multitude of
20 projections for what sea level can rise, and depending
21 on whichever, whether it's Southeast Regional Climate
22 Change, NOAA, EPA, Army Corps of Engineers, you can come
23 up with a different number for any year into the future.
24 But you bring up a point I think that is
25 probably not just constrained to the Turkey Point site

1 and our COLA. You're bringing up a point from, and I
2 don't know if it's necessarily correct, a policy issue
3 if you will, for what should be a recommendation for
4 monitoring whatever current sea level rise is and then
5 taking appropriate mitigative measures to make sure
6 that the plant maintains a safe environment for
7 operation.
8 You heard a speaker, I think here at the
9 subcommittee talk about governmental agencies planning
10 on abandoning cities if sea level rise were to go up.
11 I don't know if that's necessarily true. But we -- like
12 Steve said, we monitor, you know. We're in
13 coordination with local government entities and
14 agencies and even above these margins that Steve had
15 talked about, there are -- that's before we even start
16 talking about mitigative measures inside the fence if
17 you will.
18 There are measures that we could take to
19 protect systems and components inside the facility
20 itself. So over and above that, if there were to be
21 some guidance that comes out from the NRC for us to
22 consider or a requirement to maintain safe operation.
23 VICE CHAIR CORRADINI: So can I just get
24 the green and the blue clear in my mind. So if you
25 followed the prescribed regulatory calculational

1 procedure, what would be the predicted?
2 MR. FRANZONE: We could have taken out the
3 1.2 easily, the first 1.2 margin with the --
4 VICE CHAIR CORRADINI: And the 2.9 and the
5 1.2?
6 MR. FRANZONE: And the plant grade of 1.2.
7 The 20 percent margin I think the regulation and to be
8 honest if you could -- actually the guidance says you
9 should include it. So I would probably leave the 20
10 percent in the 2.9.
11 VICE CHAIR CORRADINI: Okay. So a
12 characterization would be to account for uncertainty,
13 you have an additional 1.2 of 1.2? That's the way I
14 would interpret what I hear, which is the 20 percent
15 margin for SLOSH is part of the regulatory requirement
16 to consider?
17 MR. FRANZONE: They recommend it, right.
18 So yes. I don't know if uncertainty is the right word.
19 I think it's extra conservatism. I don't know. I mean
20 we're nuclear and we all do --
21 VICE CHAIR CORRADINI: I know. I look
22 upon it as something that since you're uncertain, you
23 have this in your back pocket.
24 MR. FRANZONE: But it's an uncertainty.
25 MEMBER RAY: Mike, I'm not sure if you

1 meant to use the word "requirement." But again, this
2 is, as I understand it, marching in the calculation
3 methodology. It's not a regulatory requirement.
4 VICE CHAIR CORRADINI: I understand. I
5 just want to make sure I understood how they all fit
6 together. Thank you.
7 MR. MAHER: This is Bill Maher, Florida
8 Power and Light. Just to add to it, we considered sea
9 level rise as under the umbrella of antecedent sea
10 level. So it's not, you know, what is -- what we
11 considered as an antecedent, that we would then add to
12 all these calculations. We considered sea level rise
13 as part of that. So while it's not considered margin
14 here on the graph, you could come to a conclusion that
15 that could be additional margins.
16 MEMBER RICCARDELLA: This may not be
17 relevant, but just out of curiosity, what is the -- you
18 were talking 26 feet roughly elevation. What's the
19 elevation of the current units, of the currently
20 operating units?
21 MR. FRANZONE: Right. Their plant design
22 grade, I think it's 19, although they're protected up
23 to, and I'm not, don't remember if it's 22 or 24 feet.
24 They have grade protection and they intake actually
25 maybe 24. The plant itself is protected up to 22,

about. I won't say exactly. It's been a while since I've looked at them.

MEMBER RAY: Steve, you referred to Hurricane Andrew and I'm not sure what it will look like on the record, but let's just make it clear. The high level on Hurricane Andrew is well below any of these numbers; correct?

MR. FRANZONE: Correct.

MEMBER RAY: It's 15 feet high and --

MR. FRANZONE: It was, correct. And that, the actual was about ten miles, 10 to 12 miles north of the plant.

MEMBER RAY: Ten miles North.

MR. FRANZONE: Yes --

MEMBER RAY: In the area it was 50, 15 feet?

MR. FRANZONE: At the plant it was five or six feet itself, and then when you go -- since the eye went over the plant, the highest surge would have been north of that, and it was about 10-12 miles north of that.

MEMBER RAY: Okay. I just want to be clear. Thanks.

MEMBER BROWN: Can I ask a question?

MR. FRANZONE: Yes.

1 MEMBER BROWN: Does the general grade
2 cover or the build up cover the deep well injection
3 pumps as well as the other cooling pond down at the south
4 side of the -- and/or the wastewater facility?
5 MR. FRANZONE: If you go to the extent of
6 the, I'll call it the island, it starts at 19, but
7 there's a wall that goes up to 22.
8 MEMBER BROWN: Is that green line around
9 the --
10 MR. JACOBS: If you notice on the slide,
11 the 21-1/2 foot NAVD 88 is the top of the retaining wall.
12 So around the entire island it will be 21-1/2 feet.
13 MEMBER BROWN: And that includes the deep
14 well and the cooling water at the south end?
15 MR. FRANZONE: Yes.
16 MEMBER BROWN: So that green line on your
17 previous earlier slide is the retaining wall, or is that
18 just -- I don't know the color but --
19 MR. FRANZONE: I believe you're right.
20 We'll check it and then we can get back to you.
21 MEMBER BROWN: I'm just trying to
22 calibrate myself for where, what plant grade is what.
23 MR. FRANZONE: Well, the plant grade is
24 26. The site is 25-1/2 at the plant, where it meets
25 the plant, and then it's 21-1/2 foot around the entire

1 perimeter of the island, and then the individual grade
2 inside that retaining wall varies, from 19 feet at the
3 wall up to the 25-1/2 foot at the --
4 MEMBER BROWN: Okay. Effectively then
5 for the cooling water, the deep well injection pumps
6 and the other stuff that's off the main island part is
7 about four feet lower than this -- or so lower than the
8 25 or 26 feet you're talking about. Okay.
9 MR. FRANZONE: But the actual elevation of
10 the injection well, injection points haven't been
11 established yet. But the grade elevation there
12 probably is right around the wall of the makeup
13 reservoir, is about 22-23 feet.
14 MEMBER BROWN: Okay. A little less than
15 the other numbers. All right, thank you.
16 MR. FRANZONE: Right.
17 MEMBER RAY: Before you go ahead, Richard,
18 would you get back to full screen on this. Oh, that's
19 what you're trying to do. I have this personal,
20 technical point of view. I don't consider the
21 uncertainty in the calculation to be margin. I mean
22 that's accounting for the fact that that might be the
23 right answer. That's just me.
24 I also can't imagine that if those, some
25 of those alternative projections on sea level start

1 turning out to be true, that you and others won't be
2 tracking that and do something. I was hoping you would
3 say something along those lines, but somebody better
4 be tracking it because they're a whole lot different
5 than this, and they aren't very likely from what I've
6 seen. But if they happen to be true, it's pretty
7 important. Go ahead.
8 MR. FRANZONE: You're right. We work
9 with the Emergency Operations Center of Miami-Dade
10 County every year. We talk with them all the time. I
11 think it would be obvious if something drastically
12 changes in this area, that would be a major concern for
13 the county, and likewise it would be for us.
14 MR. MAHER: This is Bill Maher, Florida
15 Power and Light. Just to give some idea, Miami-Dade
16 County's building codes are floor elevations about ten
17 feet above. So I would believe and also the Everglades
18 National Park, if you look at their recommendations for
19 structure build, it's somewhere around 10-12 feet also
20 as far as floor elevation for their structures.
21 So I think as government agencies, if they
22 see sea level rise being somewhat different that would
23 impact their residents, then they would probably have
24 fiduciary value to change their building codes, to
25 start raising that and then maybe looking for other

1 alternatives to mitigate possible existing structures
2 that could be impacted by that.
3 So that's all part of the interchange that
4 we have with the government agencies. So --
5 MEMBER RAY: Well but let me interrupt and
6 say we're talking here about the antecedent water
7 level, and what that should be established to be. I
8 don't think that relates very well to the building code
9 in the city as far as the floor level of structures,
10 because we're adding then to that antecedent water
11 level various events that are pretty unlikely events
12 and might not be in a civil code domain.
13 So I'd prefer we just stick, if we can, with
14 the antecedent water level and then the things that
15 we're required to consider on top of that, one of which
16 is displayed here.
17 MR. FRANZONE: I agree. Any other
18 questions on this slide? I'm going to go back to the
19 --
20 MEMBER BALLINGER: To amplify a little bit
21 on what Dennis is saying, there's a -- if the wild
22 projection of sea level rise occurs, they'll be a lot
23 more concerns than the plant because that part of South
24 Florida will be all under water.
25 MR. FRANZONE: Right.

MEMBER RAY: But again as I say, we're talking about antecedent water level prior to imposing on top of that unlikely events. How other parts of the society react to that is quite different. The issue of monitoring whether the one foot is being undermined by accelerating rise is an issue that we'll discuss further as a committee.

MR. FRANZONE: Okay. So this is where we left off. But you will notice though that when you looked at the -- when we looked at the latter, the later data, almost 30 years' worth of later data, the linear rate didn't seem to increase that much. But I don't have anything else, unless somebody has another question on the sea level rise. Okay. Then I'll turn it over to Paul Jacobs and another interesting subject.

MR. JACOBS: Okay, thank you very much. Good morning. I'm Paul Jacobs. I'm the engineering supervisor of New Nuclear Projects for Florida Power and Light, and I'm going to briefly discuss the liquid waste management system.

Slide 18. Okay, this is historical of course, but during the early phases of the planning for Turkey Point 6 and 7, we performed a comprehensive study to determine the optimum method of supplying cooling water to the units and providing for a disposal method.

1 The screening process we used to determine
2 the best alternative considered statutory or level
3 restriction prohibiting discharge, capacity of water
4 body treatment system to treat or accommodate
5 discharge, and the technical feasibility of
6 construction and operation of discharge alternative.
7 The study evaluated nine potential
8 alternatives as indicated on the slide. The study
9 concluded that the deep well injection to the boulder
10 zone was the only alternative determined to be
11 technically feasible, could be permitted and was
12 environmentally preferable.
13 Slide 19, please. I just wanted to review
14 briefly the liquid, how we collect and discharge the
15 liquid waste. Liquid waste from the various plant
16 sources are collected in the blowdown sump. The
17 sources include cooling tower blowdown, waste water
18 retention basin blowdown, treatment from the sanitary
19 waste system and reclaimed water treatment facility
20 blowdown.
21 These processed liquid radioactive waste
22 is discharged to the blowdown sump discharge line for
23 dilution prior to release. The minimum dilution
24 factor is calculated to control the concentration to
25 no more than 10 C.F.R. Part 20, Appendix B, effluent

concentration limits, by specifying flow rates at the blowdown sump discharge. It required minimum dilution as calculated and applied product to release.

Typical dilution flow rate to achieve the compliance specified in DCD Table 11.2-8 is 6,000 GPM per unit for a rad waste tank release of 1925 gallons per day or 1.5 GPM.

Next slide, please, 20. We've prepared this drawing to provide a simplified representation, conceptual representation of the control system that will be installed to terminate the release of radioactive waste water if the dilution criteria is not met. I'd like to just review what the red and blue dictates or represents on this figure.

There are two sections of piping associated with both the rad waste and the dilution flow lines. The first one is the one that's shown in red, and that's the liquid rad waste system discharge pipe line that connects to the blowdown sump discharge pipe downstream of the blowdown sump, and that's that point that Rick is pointing to.

The red line, the main flow line is a guard pipe enclosed with a secondary containment. So the process line is inside and then we have a secondary line outside to protect against any leakage. We also have

leakage monitoring of the pipe at an underground pit, where the pipe ties in to the blowdown sump discharge, and that will be implemented as part of the radiation protection program.

The second part or the second system, piping system is that which is shown in blue, and that's from the blowdown sump that discharges the deep injection well. That piping system will be single call, partially buried and constructed -- it will have steel construction.

The piping, the manifolds, the valves that controls any of the appurtenances will be designed to minimize inadvertent releases, and leakage monitoring will consist of periodic visual inspection for the accessible portions as part of the routine operation and maintenance activities or remote surveillance as part of the ground water and monitoring program.

We prepared this figure because during the subcommittee meeting, a question was raised, which is on Slide 21. But I would like to leave Slide 20 so I could describe how we're doing this. But the question was basically what controls are available to detect and terminate the release of liquid rad waste discharge if it does not meet the calculated dilution criteria.

Our response is that there is an effluent

1 discharge flow that's -- you see it, FIR 232. It
2 monitors the discharge flow from the liquid rad waste
3 system to the environment, and maintains a record of
4 the total discharge flow for radiological assessments
5 of offsite releases.
6 The channel is used as input into the WLS,
7 which is the liquid rad waste system discharge dilution
8 ratio. The plant control system, PLS, performs the
9 flow ratio and provides the input to valve 223, which
10 is the full valve -- which is right before it connects
11 to the dilution flow line.
12 A low 1 dilution ratio causes an alarm and
13 a low 2 dilution ration causes the automatic closure
14 of valve 223. So if the dilution flow versus the rad
15 waste flow don't match as to the design calculations,
16 we terminate the flow by closing valve 223.
17 In addition, there's a high radiation
18 monitor, RE 229, that on high radiation will close valve
19 223 and stop the rad waste, the monitored tank rad waste
20 pumps, it will shut them down. So we terminate the flow
21 in two different ways. By flow, evaluating the flow
22 ratios, and as well as the high radiation, the potential
23 for high radiation.
24 MEMBER STETKAR: Paul, before you take the
25 picture off, listening to your discussion and looking

at the figure here, there's nothing that I see in this figure or your description that is different than if you were discharging into a surface stream or anything else, is there?

MR. JACOBS: No, there was not.

MEMBER STETKAR: It seems to be the fairly standard --

MR. JACOBS: It's standard.

MEMBER STETKAR: --liquid effluent discharge monitoring and isolation.

MR. JACOBS: Right. The question was raised and --

MEMBER STETKAR: No. I just wanted to make sure that I understood that. Thank you.

MR. JACOBS: Right, okay, and I might add that the red portion is part of the standard plant. So everybody will have the same thing. But the combination of the red plus the blue equals everybody else, just the point at which --

MEMBER STETKAR: I just wanted to make sure, because it looked pretty much what I was thinking. Thank you.

MR. JACOBS: Okay, thanks. Slide 23. Again, this is just a repetitive from last meeting, but just to go over the boulder zone again, the Lower

1 Florida Aquifer referred to the boulder zone is located
2 approximately 3,000 feet below ground level, and would
3 be used for circulating water system blowdown.
4 The use of the blowdown for injection of
5 sewage, industrial and domestic waste is permitted by
6 the Florida Department of Environmental Protection.
7 As noted here, the boulder zone has been used -- for
8 use of disposal of liquid waste since 1943, and there
9 are approximately 100, currently I think 190 Class 1
10 injection wells that are permitted. So it's a
11 well-tested, it's a well-known, well-tested system.
12 Slide 24 please. Another question that
13 was raised during the subcommittee meeting had to do
14 with the parameters and assumptions that we used in the
15 confinement modeling. We had a very detailed
16 discussion of the flow of the material, both laterally
17 and horizontally, and when we got to the confinement
18 modeling, this question was raised, and let me just read
19 this.
20 "The confinement model is based on the
21 assumption that the hydraulic parameters for the
22 confining strata throughout the model domain was
23 similar to the values obtained from Turkey Point
24 exploration well EW-1, and other injection wells in
25 South Miami-Dade County, which is the Florida Key

1 Aqueduct Authority and South District Wastewater
2 Treatment systems.
3 We also performed, as part of the analysis,
4 a sensitivity to evaluate the impact of variations and
5 some of the input to the program, to show what the impact
6 would be of leakier conditions. I've asked Dr. Maliva
7 to just describe in summary fashion what we did in that
8 sensitivity analysis, to take into consideration other
9 conditions.
10 MR. MALIVA: Yes. My name is Robert
11 Maliva. I'm a hydrogeologist with ESP Parsons
12 Brinckerhoff. The baseline simulation that we
13 performed used what we considered most likely
14 hydrogeologic conditions, based on the data from the
15 EW-1 and the other injection wells in the project site
16 vicinity.
17 To provide additional assurance, we did a
18 sensitivity analysis where we used less favorable
19 values for some of the key parameters, such as the
20 vertical hydraulic conductivity, effective porosity
21 and dispersivity, and the results of those simulations
22 show that after the 100 year period, even with these
23 less favorable conditions the top of the effluent would
24 still about 1,000 feet or more below the base of the
25 potential underground source of drinking water. So

1 again, there's a very large safety margin there.
2 MR. JACOBS: Thank you, Bob.
3 MEMBER STETKAR: What is that potential
4 source of drinking water? You didn't bring your nice
5 picture from the subcommittee meeting which is --
6 MR. MALIVA: Which I think we have it as
7 a backup.
8 MEMBER STETKAR: I think that would be
9 useful.
10 MR. MALIVA: That multi-colored one with
11 the two --
12 MEMBER STETKAR: Yes, shows different
13 levels with different names on them.
14 MEMBER RAY: Well, it's the upper and
15 lower.
16 MR. MALIVA: That one?
17 MEMBER RAY: Yes, there you go.
18 MEMBER STETKAR: I just want to make sure
19 that when we're talking about different -- so which of
20 these are you talking about in terms of you said the
21 potential source of potable water?
22 MR. MALIVA: It would be this line of
23 basically underground --
24 MEMBER STETKAR: Okay. Well, we can't
25 see what you pointed to, so could you --

1 MR. MALIVA: It's labeled as "Base of
2 Underground Source of Drinking Water," so it would be
3 everything above that line.
4 MEMBER STETKAR: Okay, thank you.
5 MR. MALIVA: Again, that's a U.S. EPA
6 regulatory distinction. That's water of less than
7 10,000 milligrams TVS.
8 (Simultaneous speaking.)
9 MEMBER STETKAR: Thank you. I just
10 wanted to make sure --
11 MR. MALIVA: It's not really going to be
12 used as a drinking water supply.
13
14 MEMBER STETKAR: Because we had a couple
15 of discussions during the subcommittee meeting about
16 what, which of these two levels might be used for
17 potable water. I just wanted to make sure we're
18 talking about the same thing today.
19 MR. MALIVA: So our confinement analysis
20 looked at the migration from the boulder zone in blue
21 up to that base of the USEW line. That's what we were
22 focusing on, the time, travel time to cover that
23 distance.
24 MEMBER STETKAR: And just for the record,
25 because we don't have it orally, it's the Upper

1 Floridian Aquifer.

2 MR. MALIVA: Floridan.

3 MEMBER STETKAR: I'm sorry. We were

4 corrected before, and I was hoping I'd say it correctly.

5 Floridan aquifer.

6 MEMBER BALLINGER: While you're there,

7 wherever you are.

8 MEMBER STETKAR: Bob.

9 MEMBER BALLINGER: Did you try and sort of

10 jimmy the calculation to see how far off, how

11 conservatism you had to be before you actually got

12 intrusion? In other words, how crazy did the

13 calculation have to get before you actually breached

14 it?

15 MR. MALIVA: You know, we didn't go to that

16 extent, even if we increased it beyond what we --

17 MR. PATTERSON: The microphone.

18 MR. MALIVA: No, we didn't do those

19 calculations to look at how say high we would have to

20 increase the vertical hydraulic conductivity to reach

21 that distance. We just made adjustments to the upper

22 level of what we considered could reasonably occur.

23 So we didn't try to figure out, you know,

24 if we had to increase our vertical hydraulic

25 conductivity by four orders of magnitude to get there.

1 We didn't do those types of calculations.
2 MEMBER BALLINGER: But when you say four
3 orders of magnitude, you're now making an engineering
4 judgment. Is that the kind of thing that you'd have
5 to see?
6 MR. MALIVA: Because that's really out of
7 bounds. It would be orders of magnitude, increases in
8 values beyond what was measured in the well.
9 MEMBER BALLINGER: Do you recall what the
10 sensitivity variations were in terms of hydraulic
11 conductivity or dispersivity? I have the report here,
12 but I don't remember the numbers.
13 MR. MALIVA: I think we doubled the
14 vertical hydraulic conductivity in one run. That was
15 a published one, and it didn't have a material impact.
16 And again, we're still 1,000 feet separation. So
17 there's really a -- you'd have to make very large
18 changes to cover that much difference.
19 MEMBER RAY: Well just to be clear, the
20 maximum exposure to individual dose calculations
21 assume a complete reach, and water taken from directly
22 above the breach. So okay.
23 MEMBER BALLINGER: Thank you.
24 MR. MALIVA: That concludes --
25 MEMBER RAY: Well, I've got a question yet

1 for you. In the subcommittee meeting, you talked about
2 weekly sampling of the monitoring zones, which would
3 then change to monthly after six months, each of the
4 two zones to determine if there was leakage from the
5 injection well.
6 Do you want to add anything to that
7 statement? I mean it's on the record already, but the
8 monitoring wells, their use throughout the plant life
9 would not be less frequent than monthly; is that
10 correct?
11 MR. JACOBS: Yes, what was on the slide.
12 I don't have the slide in front of me, but whatever we
13 said in that slide is the --
14 MEMBER RAY: It says "frequency to be
15 reduced to monthly after six months and Florida
16 Department of Environmental Protection concurrence."
17 MR. JACOBS: Dave, Dave McNabb can speak
18 to the details of the monitoring.
19 MR. McNABB: Good morning. My name is
20 David McNabb. Can I make this just more visible. I'm
21 not hiding from you. With regard to the sampling
22 frequency, when we first began operational testing of
23 the injection well system, we are indeed required to
24 sample on a weekly basis.
25 After approximately six months, what we do

1 is submit a request to DEP for a reduction in sampling
2 frequency to monthly. To support that request, we
3 graph up all the data of course and prove that there's
4 been no indications of say migration or demonstrate
5 that the system is operating in compliance with the
6 rules.
7 MEMBER RAY: But then it remains monthly
8 thereafter; is that correct?
9 MR. McNABB: That is correct. Any more
10 questions on Section 11.2. Okay. We'll go Emergency
11 Planning Section 13.3. Just to recap, we have two
12 site-specific approaches to the emergency planning,
13 which are associated with the location of both the
14 Operations Support Center and the Technical Work
15 Center. In response to questions during the
16 subcommittee meeting -- I almost made it.
17 In response to questions during the
18 subcommittee, we wanted to clarify the PSC
19 instrumentation power. As one member pointed out, DCD
20 Section 18.8.3.5 states the following: "An
21 uninterrupted power supply system provides
22 approximately two hours of backup power supplied to the
23 TSC displays should AC power become unavailable."
24 FPL indicates that a backup power supply
25 would be available for the TSC itself. However,

1 specifically for the instrumentation power, the
2 enterprise data server, which provides the data to the
3 TSC from the control room, is powered by the non-1E EC
4 power supply. If there was a total loss of offsite
5 power, the non-1E batteries would supply the servers
6 for two hours, allowing time for the onsite standby
7 diesel generators to be placed in service to supply the
8 battery chargers. I think that answers the question.
9 MEMBER STETKAR: Yes. I mean we have it
10 on the record now.
11 MR. McNABB: Okay. So next we'll go to
12 Chapter 19 PRA. Okay. Turkey Points Unit 6 and 7
13 aircraft craft hazard evaluation considered airport
14 operation and airway operation for large aircraft and
15 small aircraft. An approach similar to the approach
16 taken for high wind and tornado events is employed to
17 evaluate the aircraft crash hazard.
18 For the conditional core damage
19 probability, CCDP, it was assumed that the EF-3, EF-4
20 and EF-5 tornadoes and Category 3, 4 and 5 hurricanes
21 may challenge the non-safety related structures in the
22 AP1000. Now we for the high wind and tornado events,
23 the Case 2 study was created by modifying the Case 1
24 analysis for the EF-3, 4 and 5 tornadoes, and the
25 Category 3, 4 and 5 hurricane, to have a loss of offsite

power with additional failures of non-safety systems.

A CCDP was developed for this scenario, and that CCDP was calculated as the 5.85 E to the negative 8. Okay. Go ahead.

MEMBER STETKAR: I'll let you finish this slide.

MR. McNABB: Okay. The equation used for high winds was used to estimate the resultant screening TDF for the aircraft crash hazard. It is conservatively assumed that the crash of small aircraft causes the failure of standby non-safety systems. This assumption is conservative because it's unlikely that a small craft would be capable of causing such extensive failures for an AP1000 plant.

The assessment performed for large aircraft in DCD Appendix 19 concludes that an aircraft impact would not inhibit AP1000's core cooling capabilities, would not impact containment integrity and would not impact spent fuel pool integrity based on the best estimate calculations. This is the reason we used the same CCDP of the 5.85 E to the negative 8 for the CDF for aircraft impacts.

So we just took that CCDP we developed for the high winds and applied to the aircraft hazard.

MEMBER STETKAR: We now have on the record

1 what you did. I have no idea why you did what you did,
2 because high winds analyses typically do not account
3 for secondarily induced fires. Winds typically don't
4 cause fires. Fires cause things like spurious
5 signals.
6 Fire analyses tend to look at that. The
7 fire analyses in the design certification PRA are not
8 documented. They're not available publicly for a
9 variety of reasons. They're not documented. I think
10 the subcommittee, and I'll put it on the record for the
11 full Committee, some of the stuff that I could glean
12 from the design certification PRA results that are
13 available is that there is at least one event
14 characterized as a spurious ADS, spurious actuation of
15 the automatic pressurization system that had a
16 conditional core damage probability of about 5.48,
17 since we're being very, very precise here, E to the
18 minus 4, or about 4 orders of magnitude higher than what
19 you used.
20 That value by itself with an aircraft crash
21 frequency in the middle-ish, and I'll use that precise
22 value, middle-ish times 10 to the minus 7th per year,
23 would not challenge the conclusion. However, when
24 we're talking about these precise values, we ought to
25 talk about them reasonably.

1 So I still -- I don't have necessarily
2 personal problems with the overall conclusion, but I
3 have a real problem with using the conditional core
4 damage probability from a high wind event in the case
5 of a military aircraft that crashes into your buildings
6 with fuel and whatever else they might be carrying.
7 And I'll just put that on the record. It's
8 just not -- if you're trying to do a conservative
9 bounding analysis, I don't understand how this is
10 either conservative or bounding. And again, I'm not
11 arguing with your overall conclusion.
12 I think that there's reasonable evidence
13 from anything that I can find, and I can't find any
14 conditional core damage probabilities from any of the
15 fire initiating events, and it wouldn't be appropriate
16 even if I could find them to discuss them here because
17 of the location sensitivity within the plant. But I'm
18 just really curious that you hung your hat on that type
19 of an analysis.
20 MR. FRANZONE: Zach from --
21 MR. HARPER: Good morning, Zach Harper
22 from Westinghouse. I'll just provide a couple of
23 comments in response. First, you know, the method that
24 was employed for Turkey Point 6 and 7 was consistent
25 with the method that was used for DCD Revision 19, is

1 outlined in DCD Section 1958.2.3.1 for aviation
2 accidents for small commercial aircraft.
3 There was an instance where the aviation
4 aircraft for small aircraft exceeded the screening
5 criteria, and based on using a conditional core damage
6 frequency of the 5.85 E to the minus 8, a core damage
7 frequency was calculated. So when we were provided
8 with the -- with the event frequency for this
9 site-specific unit, we employed the same methodology.
10 The reason why we don't consider spurious
11 actuation of ADS like you had suggested or it was
12 discussed at the subcommittee and also here is due to
13 the work that was done in 19F for malevolent aircraft,
14 for the protection of our safety systems, which ADS is.
15 And so that evaluation concluded that the
16 safety systems were protected. Therefore, the reason
17 why we used the conditional core damage probability of
18 5.85 E to the minus 8, which was really developed from
19 the high winds, is because of the -- that number
20 includes the loss of all offsite power and certain
21 non-safety equipment, which includes loss of diesels,
22 the loss of the chemical volume control system, the loss
23 of the normal residual control systems and the loss of
24 diverse actuation.
25 So I guess the point that I'm trying to make

1 is the method that we employed for the Turkey Point 6
2 and 7 is consistent with how we handled the exceedance
3 in DCD Rev 19 when it met that criteria.
4 MEMBER RAY: Thank you. Any other
5 questions?
6 MR. FRANZONE: Okay. Thank you very much
7 for your time. That concludes our presentation.
8 MEMBER RAY: Okay. We've got two
9 minutes. According to the schedule here, we've got
10 whatever time we need in reality, but I had one sort
11 of clerical question that goes to the meteorology
12 discussion. Are these departures that are cited here
13 for the small exceedances of the wet well temperatures,
14 those are --
15 MR. FRANZONE: Correct. Those are
16 departures.
17 MEMBER RAY: Okay, all right. I just
18 wanted to make sure because it says PTN DEP here, and
19 I wasn't positive what it meant. And we had a
20 conversation just before the meeting started about PTN
21 may become important. Please tell us on the record
22 what, how PTN is used by --
23 MR. FRANZONE: The standard nomenclature
24 for Florida Power and Light plants. P is for plant,
25 T is whatever plant it's at. So for this case it's

1 Turkey Point and then N is for nuclear. We have -- the
2 fossil plants are PTF at the same site. So they have
3 PTF-1 and 2 versus PTN-3 and 4. We don't follow that
4 everywhere, but we try to follow that as a company.
5 MEMBER RAY: Okay. Well we'll put that on
6 the record. Any other questions before we go to the
7 public or the staff?
8 MR. PATTERSON: The staff.
9 MEMBER RAY: I mean before we -- yes,
10 before we go to the staff, yes. We'll use you guys
11 then. Please stand by and we'll ask the staff to come
12 up.
13 (Pause.)
14 MEMBER RAY: Good morning.
15 MR. COMAR: Good morning. I'm Manny
16 Comar, the lead project manager for Turkey Point Units
17 6 and 7. Since many things has been stated many times,
18 we'll be limiting our discussion to only a few of the
19 key topics, and I think based on the feedback that we
20 got from the subcommittee, we'll be only talking about
21 the two topics here, at least from the staff side, 2.2
22 aircraft hazards and the TSC location that was talked
23 about at the last time. But I figured it's still a good
24 idea to talk about it again.
25 May I have the next slide? As we said, we

1 are not going to brief everything on the site-specific
2 part of the application, and since neither are we going
3 to be talking about the certified design or the standard
4 content of the application. We're going to provide
5 only a high level discussion of the site-specific
6 content.
7 Next slide. To remind everybody, the
8 Turkey Point application consists of the AP1000 design,
9 design control document Rev 19, which has been
10 incorporated by reference, and of course contains the
11 standard content material, and the Turkey Point
12 plant-specific material. With that, I'm going to hand
13 it over to Tammara, who's on the my right, to talk about
14 the aircraft hazards.
15 MR. TAMMARA: My name is Rao Tammara.
16 I'm the technical reviewer for the Chapter 2 FSAR. Now
17 just to clarify the staff's position, what exactly the
18 applicant has done and what staff has made the
19 confirmatory calculations, there was a little bit of
20 a confusion, misunderstanding or whatever. Just to
21 clarify, I'm presenting this slide.
22 In response to the RAI, the applicant has
23 performed a detailed calculating using the DOE
24 methodology to calculate the aircraft impacts due to
25 the airport operations, as well as the non-airport

1 operations portion of the impacts, concerning the
2 general aviation, commercial aviation, whether it be
3 large or small aircrafts crash probabilities, or crash
4 rates, not probabilities, crash rates for the landings
5 and take-offs, and also the standard generic crash rate
6 per unit ADR from the DOE document, to account for the
7 non-operating impacts.
8 So their evaluation has been reviewed and
9 it is a DOE methodology and staff agrees with the
10 methodology and it is appropriate and acceptable.
11 The second slide. When staff reviewed the
12 portions of the impacts or contributions from the
13 impact, the airport operations impact was 2.6 10 to the
14 4 minus 7 per year, and non-airport operations impact
15 was 3.61 10 to the 4 minus 6. So from these values,
16 it can be seen that the major contribution is from the
17 non-airport impact.
18 So the staff really considered these in any
19 alternating vehicle really, make sure and have a
20 reasonable assurance using any other data. So that
21 staff had an advantage to get, acquire the actual flight
22 data from Federal Aviation Administration for the last
23 five years. So they supplied the data from origin to
24 the destination, flying within the five miles of the
25 site and ten miles of the site.

1 So therefore, we tried to utilize that
2 actual data rather than to the DOE methodology, which
3 used the generic flight crash rates per square mile.
4 So we tried to use that one and to see how we really
5 compare the analysis. So we used the -- from the reg
6 guide, the crash rate was 10 to the 4 minus 10, but we
7 reviewed the NUREG presented crash rate, which is one
8 order of magnitude lower, 3 10 to the 4 minus 9.
9 Same DOE document also documents, argues
10 the values for the military general aviation and
11 commercial different crash rates. The highest crash
12 rate is for the military operations, either for the
13 small or big. If you combine both of them, it is 1.86
14 10 to the 4 minus 8 crashes per linear flight mile.
15 So we looked at the FAA data, took the
16 highest yearly data and applied the highest military,
17 consider that highest crash rate and calculated the way
18 what will be the impact, or what will be the probability
19 of crash. Also we used the NUREG/CR-2859 recommended,
20 not recommended, presented value, 3 10 to the 4 minus
21 9.
22 So the staff, you know, performed an
23 independent analysis to make sure and also see how we
24 can compare the applicant's results using the DOE
25 methodology. So was what I try to convey, but it was

1 not probably clarified enough I think at the
2 subcommittee meeting. Therefore, I thought I would
3 give it a flavor.
4 The predominant impact is from the
5 non-operating aircraft to impact. So that, whether we
6 can really compare against the real data and see how
7 comparable it is. So that's the gist of my independent
8 analysis and these are the numbers which I have. And
9 those numbers are really comparable to the DOE
10 methodology which applicant has calculated, which is
11 somewhat lower.
12 But the highlight of this point is if you
13 really screen out the number of flights by type,
14 commercial, military or whatever. So the military
15 flights will be much lower and probably even the impact
16 will be much lower than what it is calculated, because
17 we are assuming here all the flights with the highest
18 probable, highest crash rate, and still we are
19 comparing it lower than the DOE value.
20 So it has a reasonable comparison and a
21 conservative, overly conservative value and it has a
22 reasonable assurance that the crash aircraft impact
23 will have any undue risk to the operation of the plant.
24 That is my conclusion.
25 MEMBER STETKAR: Thank you. You haven't

1 addressed the issue that we brought up in the
2 subcommittee, and apparently we aren't communicating
3 very well. I understand that you did a confirmatory
4 analysis for the in-flight aircraft crash rate on
5 flights in the aircraft at control corridors that fly
6 near the site.
7 My question was what independent analysis
8 did you do for the airport operations at Homestead?
9 MR. TAMMARA: Because it is -- even
10 though if I use the DOE methodology, using the same
11 crash rates as that of the applicant, and if I have to
12 come up with the same kind of flights, the impact is
13 order of magnitude lower than the non-airport impact.
14 So even though you refine your calculation or whatever,
15 I don't see any benefit of reproducing the same equation
16 with the same number of flights.
17 MEMBER STETKAR: That's what I was asking
18 you about in the subcommittee meeting is you said even
19 if you use the same. The fact of the matter is you did
20 use precisely the same. You did not look at any other
21 alternative than the DOE crash rates for military
22 aircraft at military facilities and the DOE model for
23 the distribution of those crashes as a function of
24 aircraft size, given take-off and landing patterns for
25 military bases.

1 You simply confirmed that indeed they, the
2 applicant, used the values. I did that. I did that.
3 It's an hour calculation. I did that. Now if -- let
4 me finish. I also did a couple of sensitivity analyses
5 to look at uncertainties in the distribution of the
6 aircraft crash rates, and I can get up to about an order
7 of magnitude crash impact frequency at the site.
8 That does not alter the overall
9 conclusions. That still does not alter the overall
10 conclusions from the analyses. What I'm trying -- what
11 I was trying to do and what I'm still trying to do and
12 I understand what you did, is to understand what type
13 of so-called independent confirmatory analyses the
14 staff did for all sources of aircraft crashes. I
15 understand what you did, so I appreciate that. Thank
16 you.
17 By the way, just as a -- do you have any
18 comments on the use of this 5.85 times 10 to the minus
19 8th conditional core damage probability that was used
20 in the analysis? Did you look at all at that?
21 MR. TAMMARA: No. That was the DCD
22 value. We have taken that one. But the other option
23 I had was to even if I considered all the aircrafts going
24 in that airway of an eight mile width, my number was
25 much lower using that one, 10 to the 4 minus 7. So you

can screen out even without applying the conditional core damage frequency, really speaking.

From my calculation, I have used the -- the very first calculation is using the 3.10 to the 4 minus 9. The probability is 5 10 to the 4 minus 6, 10 to the 4 minus 7. So that is probably a more realistic value than overly conservative value considering all the flights are military type, and having a probability of 8.6 10 to 4 minus 8 crash rate. So that would put me in a non-exceedance criterion.

CHAIRMAN BLEY: You know, on your previous slide you talked about core damage probability for AP1000. At the time we reviewed the AP1000 design cert, the version of the PRA that was current was Rev 8. Two things about it. One is there was no aircraft crash analysis in that version of the PRA, and two, that whole PRA doesn't come close to meeting the technical adequacy requirements of Reg Guide 1.200, which is okay for the PRA at this stage.

But there is a PRA that needs to be submitted before fuel load, and I sure hope the staff does some audits on that PRA to make sure it's up to the 1.200 standards.

MEMBER BALLINGER: Let me get a little bit of a clarification. This three times, what this 1.86

1 times 10 to the minus 8 craft for military aircraft,
2 is that an average?
3 MR. TAMMARA: Yes.
4 MEMBER BALLINGER: So it's an average.
5 So you didn't look at different aircraft types, because
6 the crash rate for airport operations, for different
7 aircraft types, especially fighter aircraft is way
8 different.
9 MR. TAMMARA: Yes. But what my
10 consideration is, DOE has given the different types of
11 aircrafts.
12 MEMBER BALLINGER: Okay, types.
13 MR. TAMMARA: And they have given the
14 crash rates, and the applicant has calculated using
15 those crash rates.
16 MEMBER BALLINGER: Okay.
17 MR. TAMMARA: For the take-off and
18 landings. So they have given the two portions in the
19 aircraft operations impact and then the non-aircraft
20 state what were the flights. So if you compare those
21 two values, the dominant impact is from the non-airport
22 operations. Then landing and take-off for impact,
23 airport operations, 2.55 10 to the 4.
24 I have given broken down on flight 7. So
25 the major contribution is from the non-airport impact

in order of magnitude. So therefore my confirmatory calculation, I concentrated to really compare that value using the real data, you know, real data and more conservative assumption. I will really compare that 1R, the DOE's generic value is really applicable or not. That is the basis of my thought process to compare.

MEMBER BALLINGER: Thank you.

MEMBER RAY: Okay, anything further? Go ahead.

MR. PATTERSON: This is Malcolm Patterson. I'm with the PRA staff in the Office of New Reactors. I just wanted to clarify one thing, which is that the PRA that is prepared prior to fuel load will not be submitted to the staff.

CHAIRMAN BLEY: I didn't say review; I said I hope you --

(Simultaneous speaking.)

MR. PATTERSON: We will have that opportunity.

MEMBER STETKAR: I think just for the record we're saying we really hope you take that opportunity.

(Off mic comments.)

MR. MUSICO: Good morning. My name is Bruce Musico. I'm a senior emergency preparedness

1 specialist. I reviewed the proposed emergency plan in
2 support of the Turkey Points Units 6 and 7, and authored
3 the Section 13.3 of the advanced safety evaluation.
4 During the subcommittee meeting, I didn't
5 have a formal presentation, but I was asked to respond
6 to a number of questions. Today what I'd like to do
7 is very briefly address the three areas that were --
8 that I was questioned on during the subcommittee
9 meeting as they relate to emergency preparedness.
10 Specifically, it was the TSC location with
11 regard to the two minute walking distance between the
12 TSC, the Technical Support Center and the control room.
13 Secondary was the TSC power supplies, and the third area
14 was the siting criteria in which I discuss the
15 evacuation time estimate in protection of the people
16 surrounding the Turkey Point site.
17 With regard to these issues, I just want
18 to make some preliminary comments regarding the site.
19 The Turkey Point site has been there for a long time.
20 Specifically Unit 3 received its operating license in
21 1972, and Nuclear Unit 4 received its operating license
22 in 1973.
23 A major event in the emergency
24 preparedness world was the Three Mile Island, TMI
25 accident in 1979, after which the NRC revised its

1 regulations and guidance to specifically account for
2 the various types of accidents and lessons learned from
3 the TMI accident and the NRC's response at that time,
4 including the requirement to have a Technical Support
5 Center among other facilities.
6 With regard to the regulations that were
7 developed after TMI in the period of about 1979 to
8 '82-ish, these regulations are basically the same
9 regulations that exist today. There have been
10 additional requirements associated with Fukushima, the
11 9/11 incident and various other influences on emergency
12 preparedness, but the basic requirements are the same
13 as they were in approximately 1981, when they went into
14 effect.
15 So what that means is that the existing
16 Units 3 and 4 have been operating under those
17 requirements for in excess of about 35 years. Over
18 that period of time, the emergency preparedness program
19 is an ongoing operational program that the Nuclear
20 Regulatory Commission, in coordination with our
21 federal partner in FEMA, the Federal Emergency
22 Management Agency, continuously monitor the
23 operational aspects of that implemented plan in support
24 of Units 3 and 4, and there are periodic exercises that
25 we also monitor and critique and evaluate both onsite

1 and offsite performance, and again we do this in
2 coordination with FEMA.
3 So what we have here is an active site
4 that's had an operational emergency planning program
5 in place for in excess of 35 years under basically the
6 same regulations that exist today, with some
7 refinements or what we refer to as enhancements over
8 the years.
9 So the finding that we make with regard to
10 our review of the emergency planning program is a
11 finding of reasonable assurance, and we think we've
12 found that in support of the proposed Units 6 and 7.
13 Now getting to the first slide, this was the first,
14 excuse me, area that I was questioned on during the
15 subcommittee meeting with regard to the two minute
16 walking distance between the Technical Support Center,
17 TSC, and the control room during an accident.
18 As I mentioned during the subcommittee
19 meeting, off the top of my head there were -- there are
20 two basic reasons that support that two minute walking
21 distance. It comes from NUREG-0696, which is a 1981
22 document and the first bullet, the first requirement
23 supporting the two minute walking distance was "to
24 provide necessary management interaction and technical
25 information exchange," and I got this directly from the

1 guidance document, 0696.

2 The second was to provide TSC access to

3 control room information not available in the TSC data

4 systems. Then you see that first dash under the second

5 bullet, where it says "During recent events at nuclear

6 power plants, telephone communications were

7 ineffective in providing all of the necessary

8 management interactions and technical information.

9 Well, it was interesting, because they

10 just say "telephone communications." They don't get

11 into the more advanced communication systems that exist

12 today. So that was -- that forms the basis for the two

13 minute walking distance.

14 Now what we've seen over the past several

15 years is a trend in the power plants to not only combine

16 the Technical Support Center capabilities in support

17 of sites that have multiple units, but to take advantage

18 of a relaxation of the two minute walking distance from

19 the TSC to the control room.

20 So can I have the next slide? What I've

21 done here is identified several references where this

22 question of the relaxation of the two minute walking

23 distance came up, and these are references where the

24 second, for the Vogtle early site permit application

25 you can see I actually sat here and presented, maybe

in the other room, and presented before the ACRS responding to questions regarding the relaxation of the two minute walking distance for the Vogtle site, in which we have a common Technical Support Center proposed, and it's approximately ten minute walking distance from the control room. So that's a good reference you might want to look at.

Subsequent to that, during the Vogtle early site permit Atomic Safety Licensing Board proceedings, where I testified before them, we received prior questions before the hearing, which was conducted down in Georgia, one of which had to do with the two minute walking distance.

I took advantage of some of the things I had to say before the ACRS and I expanded on that. So if you look at that reference, you'll see basically a comprehensive discussion regarding the relaxation of the two minute walking distance, and what we based our acceptability of that on.

CHAIRMAN BLEY: Bruce, can I interrupt you?

MR. MUSICO: Yes, sure.

CHAIRMAN BLEY: On your previous slide, one of your sub-bullets talked about a number of events at power plants where the telephone communications were

1 ineffective. Are any of those described in the
2 references on your next slide?
3 MR. MUSICO: No, no.
4 CHAIRMAN BLEY: Can you give us any
5 reference to that, because I don't remember those kind
6 of events, and I'd be very interested.
7 MR. MUSICO: Actually I found that curious
8 too, because remember this was a 1981 document, where
9 you know, I kept thinking about post-TMI. But they
10 didn't identify that I recall any additional instances
11 where they had that problem. I would -- I could
12 speculate that at that time, I think that was before
13 -- or at the time when we were requiring a Technical
14 Support Center to be established, that might have
15 reflected exercises or possibly incidents that
16 occurred at existing sites prior to the imposition of
17 Technical Support Centers for those sites.
18 In that case, they would see the crowding
19 of the control room. So I assume that was in reference
20 to that. But I usually refer to -- I usually associate
21 that with TMI. But again there apparently were
22 additional instances in which they did not --
23 CHAIRMAN BLEY: We don't have a record of
24 that. Okay, thank you.
25 MR. MUSICO: No, no, I don't. There are

1 possibly, there are probably inspection reports that
2 if we really wanted to, we could go back and look at
3 them, and we'd probably find comments to that effect.
4 Possibly the documents that were developed in support
5 of writing NUREG-0696. That possibly would explain
6 that, but I didn't see any of those.
7 Okay. Then we have some additional
8 references there that you can also look at, including
9 the outage numbers so they're easy to find, that again
10 provide a more comprehensive description of why we are
11 allowing relaxation of the two minute walking distance.
12 In essence, it was the advancements of
13 various communications equipment and data processing
14 and transmittal equipment that's now available. One
15 other -- one other important point that I didn't bring
16 up during the subcommittee meeting is that if -- we
17 conducted the review of the application and the
18 proposed emergency plan in support of 6 and 7 in
19 accordance with the Standard Review Plan, which is
20 NUREG-0800.
21 Specifically in 0800, Section 13.3 is
22 entitled "Emergency Preparedness," which I wrote and
23 also in Section 14.3.10 is Emergency Planning ITAAC,
24 which I also wrote. In 14.3.10, we have a table of
25 generic EP ITAAC that is used by prospective applicants

1 to develop application-specific EP ITAAC in support of
2 COL applications or early site permit applications, if
3 that's the case.
4 I specifically want to point you to the
5 Table 14.3.10-1, entitled "Emergency Planning Generic
6 ITAAC," Planning Standard 8.0, Emergency Facilities
7 and Equipment. If you look under acceptance criteria
8 8.1.2 it -- now these acceptance criteria, when I was
9 developing them, I modeled them after the acceptance
10 criteria in NUREG-0654. That was the basis for the
11 generic EP ITAAC.
12 So in here, we have acceptance criteria
13 8.1.2 which says "The TSC is close to the control room,
14 and the walking distance from the TSC to the control
15 room does not exceed two minutes," and that reflects
16 what is in NUREG-0696, which is referenced by
17 NUREG-0654. That's how it comes into play.
18 Now when the initial draft EP ITAAC table,
19 we conducted a number of public meetings with industry,
20 with the Nuclear Energy Institute, NEI, and one of the
21 comments they had was the possibility of relaxing this
22 two minute walking distance. This was in, I think it
23 was 2007, March of 2007, when the Standard Review Plan
24 was revised, and we didn't compromise but we came up
25 with an approach that we thought about very closely.

1 We considered the various aspects
2 associated with relaxing the two minute walking
3 distance, similar to the basis that are addressed in
4 a lot of the references there, and we added a bracketed
5 statement here to address this two minute walking
6 distance and application, which specifically says
7 "Advanced communication capabilities may be used to
8 satisfy the two minute travel time."
9 All right. So from our guidance document,
10 it accounts for and allows a relaxation of the two
11 minute walking distance, and that was what we put in
12 there to allow them to make the case. They have to make
13 the case why they can relax this two minute walking
14 distance, and the ones that we've seen have been
15 successful in that regard in our opinion in support of
16 the reasonable assurance finding. So that's
17 important.
18 MEMBER RAY: Is it appropriate to update
19 0696 then?
20 MR. MUSICO: It depends, because 0696 was
21 a snapshot in time reflecting a lot of the lessons
22 learned from the TMI accident. There have been a lot
23 of additional events that may in fact necessitate an
24 updating of it. However, if you look at the Standard
25 Review Plan, the Standard Review Plan, NUREG-0800,

1 13.3, when I was writing it, I was looking at 0696 and
2 I was in fact updating it to a certain extent as far
3 as prospective applications, COLs or ESPs.
4 So the vehicle for updating the
5 information in 0696 may not be a revision to 0696. It
6 may in fact be an updated revision of the Standard
7 Review Plan NUREG-0800. But the short answer is
8 probably yes, it could be updated.
9 MEMBER RAY: In the interest of time, I
10 won't pursue it further. I interpret that as a yes
11 because having the Standard Review Plan override lots
12 of guidance that exists is -- or I won't say override,
13 but to modify it is probably not in everyone's interest
14 long term.
15 MR. MUSICO: Well, the Standard Review
16 Plan neither overrides nor modifies additional
17 guidance. It merely incorporates that into it.
18 MEMBER RAY: Well, in this case, I'm just
19 referring to the parenthetical piece. But I won't --
20 I don't want to push it further because we're running
21 out of time.
22 MR. MUSICO: It augments the two minute.
23 MEMBER RAY: Let's not get into semantics.
24 MR. MUSICO: Okay.
25 MEMBER RAY: Proceed please.

1 MR. MUSICO: Yes, thank you. The next
2 slide. This is just some simple information I pulled
3 out of the emergency plan as well as the safety
4 evaluation report, which reflects the emergency plan.
5 The first bullet are just various aspects
6 of the TSC, which is going to be in the Turkey Point
7 Nuclear Training Building, and as you can see, the
8 middle clash talks about the distance between the TSC
9 and the control rooms and approximately 10 to 15 minute
10 walk.
11 The second bullet and the third bullet
12 merely reflect the two areas that form the basis for
13 the two minute walking distance, as far as advanced
14 communication and advanced technical information
15 exchange data systems.
16 Next slide, please. This is a second area
17 that the Committee asked me about with regard to the
18 TSC, and I believe the applicant adequately addressed
19 that with respect to the power supplies to the TSC.
20 From an emergency preparedness standpoint, you can see
21 the first part again comes from NUREG-0696, and the
22 third slash is kind of the basic criteria we look to
23 from an emergency preparedness standpoint in our
24 review.
25 It is "sufficient alternative or backup

power source shall be provided." It doesn't really get into the specific nature of it except for the other slashes, but we look for a backup power supply system, and the adequacy of that power supply may be evaluated elsewhere.

Then the second bullet, the Turkey Point common TSC, they've said that they will have a reliable and backup electrical power supply is available, and they addressed that just a few minutes ago, and we have in the safety evaluation report there is an ITAAC, EP ITAAC 5.1.6 acceptance criteria, where we will in fact verify that that backup power supply exists.

So that's the extent of our involvement with respect to reviewing the power supply to the TSC. Next slide, please.

MEMBER STETKAR: Don't go to the next slide yet.

MR. MUSICO: Yes.

MEMBER STETKAR: It's interesting listening to these exchanges because I'm fully aware of the requirements for a backup power supply to the TSC. My original question was if I have all of the power in the world at the TSC, but I cannot power any of the instrumentation in the power plant that is driving the signals to the TSC, having a TSC with the

1 lights on but no information available is essentially
2 useless.
3 So my question was how do you have
4 confidence that the information will be available in
5 the TSC given the fact that the power supplies for the
6 instrumentation and communications, and now I'm
7 talking about signal communications, not telephones,
8 to the TSC are non-safety-related and are backed up by
9 batteries that have a rated life of two hours, and for
10 the record, Turkey Point did answer that question this
11 morning. It had nothing to do with power supplies for
12 the TSC.
13 So I wanted to correct what you just said
14 on the record in terms of what Turkey Point addressed.
15 They did address my question. You didn't, because
16 you're not communicating. See, you're only looking at
17 the TSC as if it's something in isolation and I
18 understand that. What's what the staff does.
19 I was asking a more general question for
20 the site and things that drive the power, the
21 information to the TSC. So the site is essentially
22 relying on their backup emergency station blackout,
23 let's call them diesel generators or whatever to
24 restore AC power to the non-safety-related
25 instrumentation control system within the two hour life

1 of their non-safety-related batteries.
2 So that the TSC, sitting there waiting to
3 receive the information, can actually receive the
4 information.
5 MR. MUSICO: Well, I'm not sure what I said
6 that you were referring to that needed correction but
7 --
8 MEMBER STETKAR: You said that -- you said
9 that Turkey Point addressed what you're talking about
10 on this slide. They did not.
11 MR. MUSICO: Well, they did -- they did
12 address Class 1E requirements as far as the first slash
13 there under the first bullet.
14 MEMBER STETKAR: That's true. They did
15 --
16 MR. MUSICO: That's what I was --
17 MEMBER STETKAR: Okay. I don't want --
18 we're short for time.
19 MR. MUSICO: But to address your other
20 comment with regard to the reliability or nature of the
21 power supply, that's not within the scope of the
22 emergency planning review. We merely look for backup
23 power supply. The reliability is not something we get
24 into in detail from an EP standpoint.
25 MEMBER STETKAR: I understand that, and

1 we're still not communicating, so I just -- you are
2 talking only about the power supply to the TSC. That
3 is the building that houses people who man the Technical
4 Support Center. If they do not have information
5 available to them, their job becomes a lot more
6 difficult.
7 I'm talking about the power supply over in
8 Turkey Point Unit 6, let's say, that drives the signals
9 that comes to the displays to the people who are sitting
10 in the TSC, looking at the displays that they need that
11 are powered by some reliable backup power supply.
12 MR. MUSICO: I believe we have backup
13 communication capabilities, that if one system went
14 down, they have other facilities, other equipment that
15 can compensate.
16 MEMBER STETKAR: That's what -- that's --
17 okay. I'm just going to leave it to Harold in the
18 interest of time. We've got it on the record.
19 MR. MUSICO: And I've addressed those
20 various communication capabilities in the safety
21 evaluation report, which reflects the emergency plan.
22 MEMBER RAY: Okay. I've got two minutes
23 to get to the end.
24 MR. MUSICO: Oh, I'm sorry. All right,
25 next slide please. Then this is the final area, which

1 I'll cover briefly. The question came up with respect
2 to the criterion Regulatory Guide 4.7 regarding the 500
3 persons per square mile up to 20 miles.
4 I responded to that with regard to the
5 evacuation time estimate that was performed for the
6 site. I wanted to clarify that a little bit. First
7 of all, the evaluation of the 500 persons per square
8 mile up to 20 miles, that's not an emergency planning
9 review area that we specifically look at. It's not
10 emergency preparedness per se.
11 However, which as you mentioned during the
12 subcommittee meeting, there are people out there, and
13 this does affect them with respect to protecting them
14 in the event of an accident. My response was the
15 evacuation time estimate, which accounts for a
16 population and reflects that within the offsite
17 protective action decision-making that comes about as
18 a result of the state and local governments responding
19 to an accident.
20 One clarifying point I wanted to make here,
21 that the ETE only goes out to ten miles, and so, you
22 know, what happens from ten miles to 20 miles now.
23 Well, if you look at the basis for the ten mile emergency
24 planning zone, as well as the 50 mile ingestion pathway
25 zone, one of the original documents that established

1 the 10 and 50 mile EPZ was NUREG-0396, and that was a
2 December 1978 document, which established the basis for
3 the 10 mile EPZ and the 50 mile EPZ.
4 The 10 mile EPZ was based in that document
5 on various design basis accidents, a worse case for a
6 site, as well as the distance out to which a possible
7 dose would not exceed the protective guidelines in the
8 Environmental Protection Agency, the EPA PAGs. That
9 was the basis for the ten mile EPZ.
10 In the document, they also in establishing
11 the 10 and 50 mile emergency planning zone, with regard
12 to the ten mile EPZ, they do address beyond ten miles
13 and they state that if the accident necessitated
14 protective actions beyond ten miles, that protective
15 action would be implemented on an ad hoc basis.
16 So that's how that's addressed, and we see
17 that reflected in offsite emergency plans for the
18 various sites. So I just wanted to clarify that
19 distance here. That's all I have.
20 MEMBER REMPE: Bruce, unfortunately I had
21 to leave the last part of the subcommittee meeting, and
22 when you were asked about this population density, you
23 retorted with a question back about well, at the time
24 that the Turkey Points 3 and 4 were originally sited,
25 it met the population density requirement, and you said

1 could I ask you back a question about to what extent
2 is it applicable to additional units at the existing
3 site, and none of my colleagues queried you about that.
4 I'm just curious, because of the small
5 modular reactor issues and all that. Are you trying
6 to tell us that if you have an existing site approved
7 and the population density is fine, doesn't matter if
8 you put a couple more units on the site?
9 MR. MUSICO: I don't know the answer to
10 that, and that's why I have been told in the past not
11 to pose questions to the ACRS, but to answer them.
12 (Laughter.)
13 MEMBER REMPE: It might be good guidance.
14 MR. MUSICO: If you also look at the
15 transcript, which you're looking at -- I knew somebody
16 would bring that up, I haven't had my performance
17 evaluation yet but I'm sure that will come up during
18 that. If you look at the transcript, I think I prefaced
19 that comment, that question "I probably shouldn't ask
20 this but," and I think that's the last time I'll ever
21 pose a question to the ACRS.
22 But the short answer is I don't know what
23 the answer is, and I think I also mentioned after that
24 that the individual that dealt with the 500 persons per
25 square mile criteria in the review, I think that as

1 Standard Review Plan Section 2.1, 2.2, would probably
2 be the person to address that.
3 It may not be relevant with respect to not
4 exceeding or not greatly exceeding the 500 persons per
5 square mile of the 20 miles that's in Reg Guide 4.7.
6 So I don't know if that's really a valid question, but
7 I think that's the last time I'll ever ask it.
8 (Simultaneous speaking.)
9 MR. MUSICO: Thank you for bringing that
10 up. I'm sure this is all recorded too.
11 MEMBER RAY: The praise isn't greatly
12 exceeding, it's well in excess. But let's move on.
13 Let's not pursue that any further. Manny, do you have
14 anything more?
15 MR. COMAR: Unless the Committee has any
16 other questions, that's all.
17 MEMBER RAY: Are there other questions
18 before we open the phone line, or ask here in the
19 audience if there are any public comments. Any other
20 questions for staff? If not, then I'll as usual look
21 around, asking if the phone line can be opened, and
22 meanwhile ask if there's anyone here in the audience
23 who, as a member of the public, wishes to make any
24 comment?
25 (No audible response.)

1 MEMBER RAY: Seeing none and being advised
2 that the phone line is open, we began the meeting with
3 folks on the line. Is there anyone on the line who
4 wishes to make a comment at this time?
5 (No audible response.)
6 MEMBER RAY: Hearing none, I turn it back
7 to you, Mr. Chairman, actually five minutes early.
8 MEMBER STETKAR: Very good job. Thank
9 you very much. At this time, we will recess until
10 10:45, when we'll take up the next issue.
11 (Whereupon, the above-entitled matter
12 went off the record at 10:24 a.m. and resumed at 10:47
13 a.m.)
14 CHAIRMAN BLEY: Meeting will come back to
15 session. Technical problems are sort of solved, and
16 we'll go ahead. Mr. Brown, it's your turn.
17 MEMBER STETKAR: Turn your mike on.
18 MEMBER BROWN: To avoid windage, I will
19 turn it over to Mr. Lubinski, so he can -- John Lubinski
20 -- so he can introduce the staff, and we'll go from
21 there.
22 MR. LUBINSKI: Thank you, Charlie. John
23 Lubinski, Director of Division of Engineering in the
24 Office of Nuclear Reactor Regulation. I appreciate
25 the opportunity to be here today to --

1 CHAIRMAN BLEY: Are you in your mike?

2 MR. LUBINSKI: John Lubinski, Director,
3 Division of Engineering, Office of Nuclear Reactor
4 Regulation. I appreciate the opportunity to be here
5 today to discuss the staff's final evaluation of the
6 license amendment request from Diablo Canyon for its
7 digital upgrade system.

8 This is the completion of our evaluation,
9 and we understand that ACRS will be writing a letter
10 in response to our SE, and we appreciate the time and
11 effort for the meeting today, as well as the review of
12 that safety evaluation. We had many folks in the NRC
13 participate in this evaluation, and I want to express
14 my thanks and appreciation to them. Some of them are
15 here in the room today, others are not.

16 Given the time, we've limited the number
17 of staff doing presentations today, and I will
18 introduce them this morning. We have Mike Waters, who
19 is Director of the Instrumentation and Control Branch
20 in Division of Engineering. We also have Balwant
21 Singal, who is the project manager for Diablo Canyon.
22 And then we have Rich Stattel, who is the lead technical
23 reviewer on this application and will be doing the
24 majority of the presentation.

25 Also in front of the room today, we have

1 Ken Schrader from Diablo. He will not be doing a
2 presentation but is here today to answer any questions.
3 So with that, I'll turn it to Mike.
4 MR. WATERS: Yes, thank you. Good
5 morning. I'd also like to express thanks to Christina
6 for helping arrange and coordinate the meetings the
7 past few years.
8 Very quickly, the agenda. Balwant will go
9 over the project review. Then we'll turn it over to
10 Rich to talk about part of the staff's safety
11 evaluation. He'll summarize the subcommittee meeting
12 we had earlier this year and some key issues that we
13 responded to. And as time allows, Rich will discuss
14 our lessons learned in ISG-6, the primary document we
15 used for the licensing review.
16 With that, I'll turn it over to Balwant.
17 MR. SINGAL: My name is Balwant Singal.
18 I'm the project manager for Diablo Canyon. Okay, I'll
19 repeat. My name is Balwant Singal. I'm the project
20 manager for Diablo Canyon from headquarters. I will
21 be just going over a short summary of the licensing
22 activity we have performed since we received the
23 license amendment request in 2011.
24 The application was received on October
25 26th, 2011, and this was the first-of-a-kind design

1 change and Diablo happened to be the lead point, a lead
2 plant for this kind of activity. And then they were
3 assigned the fee waiver for the review of this
4 application.
5 The application was accepted by the NRC
6 staff on January 13, 2012, and there were a number of
7 branches involved with the review, but there are two
8 key branches. One is the instrument -- the key
9 branches, the Instrument and Control branch, we call
10 EICB, and the PRA branch. That's so the branches will
11 be just on conference. They don't have any safety
12 evaluation input.
13 Since we received the application, from
14 May 2012 to July 2015, we have conducted 32 public
15 meetings on this topic specific to Diablo Canyon. We
16 have conducted four audits. I believe all the audits
17 were on site, audit investigators office. Then we had
18 four RAIs, requests for additional information,
19 between 2012 and 2015. The licensee made about 25
20 submittals between October 2011 to now, and we had two
21 ACRS subcommittee meetings and one full subcommittee
22 meeting between February 2014 and April 2016.
23 As of now, the status of the package is that
24 we have the draft back already, but we are waiting for
25 the comments or recommendations from the full committee

1 meeting to finalize the package. And then after we
2 have the full committee level, we'll be, basically,
3 sending the package to the rest of the branches.
4 That's all I have, unless any questions or
5 comments. I'll turn it to over to Rick Stattel for
6 going over the technical, some of the other technical
7 review.
8 MR. STATTEL: Thank you, Balwant. I am
9 Richard Stattel, and I'm the lead reviewer on this
10 evaluation. I'm going to start out by giving a little
11 overview, explain where the process protection system,
12 that's the modification we're looking at, where it fits
13 into the plant design.
14 So this diagram is right out of the license
15 amendment, and it shows in the red box that you see
16 there, that is the process protection system. You can
17 see it's an integral part of the reactor protection and
18 engineered safety features systems, but the blocks that
19 are around it, for instance the nuclear instrumentation
20 block that's right underneath the process racks, those
21 are also key components of the reactor protection and
22 the SFAS systems for the plant.
23 So I'll be referring back to this. You
24 know, this is kind of the high-level concept, and this
25 modification that we're looking at is only replacing

1 those process racks. They received a sensor input from
2 the field, and they provide the trip or actuation
3 signals to the solid state protection system, which
4 actually does all the relaying and actuation of
5 devices, field devices.
6 MEMBER SKILLMAN: Richard, when you
7 communicate, this addresses changing the racks. When
8 I think of rack, I think of cabinet with an interior
9 steel structure but not the devices that are retained
10 in those cabinets. I believe you're referring to
11 everything that is within the enclosure and the
12 enclosure itself. Is that accurate?
13 MR. STATTEL: Actually, in this
14 particular case, that's an interesting question
15 because the plant has decided to, they're replacing an
16 existing system, an Eagle 21 system. They're
17 retaining the same rack, the same enclosures. So
18 they're basically gutting those enclosures, and
19 they're going to be re-terminating the field wires to
20 the new system. And that's actually a key part of the
21 environmental qualifications, and it was a
22 complication that we had to deal with. That's one of
23 the delays that we had because we couldn't qualify the
24 system in those racks because they're in use. The
25 plant is operating with Eagle 21 installed in those

1 racks today.

2 MEMBER SKILLMAN: That clarification is

3 necessary for me because it leads to the seismic

4 questions that I want to ask.

5 MR. STATTEL: Sure. Yes, we understand

6 that.

7 MEMBER SKILLMAN: I hear you say the box

8 stays, they gutted the box. They're running new

9 terminations, and they're putting new devices in those

10 boxes.

11 MR. STATTEL: That's correct, yes. We're

12 going to hit that because that was the one outstanding

13 open item.

14 CHAIRMAN BLEY: I'm sorry. If you make

15 comments again, turn on your microphone. It's part of

16 the meeting.

17 MR. SCHRADER: Okay. This is Ken

18 Schrader. I just wanted to clarify that the racks, in

19 order to meet the seismic qualification, the cabinets,

20 we will make some modifications inside the cabinets,

21 you know, from the supports.

22 MEMBER SKILLMAN: Thank you. I

23 understand it, but now it's clear in my mind that when

24 you say rack you're talking about stuff inside existing

25 boxes. Thank you.

1 MR. STATTEL: Okay. The next figure
2 here, this shows the safety functions that are
3 performed by --
4 MEMBER BROWN: Richard, back up one slide.
5 I had a question that was asked of me that I couldn't
6 answer. The box that says field contacts, what is
7 that?
8 MR. STATTEL: Well, I'll give an example.
9 There are several inputs that are fed directly into the
10 solid state protection system --
11 MEMBER BROWN: And you made that comment
12 in the SE --
13 MR. STATTEL: One example of that is the
14 seismic, so Diablo Canyon has a reactor trip that occurs
15 on a seismic event.
16 MEMBER BROWN: Right. And they do not go
17 through the PPS system.
18 MR. STATTEL: They do not go through the
19 process protection system at all. Their direct feeds
20 into the solid state protection system, so that's
21 really not part of our evaluation or this modification,
22 but this figure shows that in the field contacts block.
23 MEMBER BROWN: I just wanted that
24 clarified, that's all. Thank you.
25 MR. STATTEL: Okay. So what exactly does

1 the process protection system do? This figure shows
2 the safety functions that are performed by the process
3 protection system in terms of inputs, which are the left
4 blocks, the processes, which are in the center, and the
5 outputs that are on the right side of the figure. This
6 is the existing Eagle 21 process protection system. On
7 the left are the monitored plant parameters or inputs
8 to the process protection system.
9 I'll go ahead and decode the colors for you
10 here. The blue boxes represent parameters that are
11 used to perform reactor trip functions. The pink boxes
12 represent parameters that are used to perform
13 engineered safety features, and the purple boxes
14 represent parameters that are used to perform both
15 reactor trip and ESF functions.
16 In the center is the existing Eagle 21,
17 which is a microprocessor-based PLC system. PLC is
18 programmable logic controller. Currently, all of the
19 PPS functions are performed by the digital Eagle 21
20 based system. Eagle does have four redundant
21 protection sets, but they all use the same basic
22 software to perform those functions. That's an
23 important point that will come up later.
24 On the right side of the figure are
25 functions that are supported by the process protection

1 system. The top red box is the reactor trip function.
2 All of the other orange boxes are the individual safety
3 features that are performed by the process protection
4 system.
5 This next figure, the process protection
6 replacement system will replace the Eagle 21 computer,
7 PLC computer, with two separate subsystems. The first
8 in the dark blue box is the microprocessor-based Tricon
9 subsystem, which is also a programmable logic
10 controller, or PLC, based system. The second in the
11 orange box is the Westinghouse Field Programmable Gate
12 Array, or FPGA, based advanced logic systems subsystem.
13 Both of these platforms were previously
14 evaluated by the NRC and were approved for use in
15 safety-related applications. Each platform safety
16 evaluation identified application-specific action
17 items to be addressed once the application was
18 developed and to ensure compliance with the applicable
19 regulations. And we've now completed those follow-up
20 application evaluations.
21 As part of the safety evaluation for this
22 amendment, the NRC staff performed
23 application-specific reviews and determined that each
24 of the Diablo Canyon subsystems were developed in
25 accordance with acceptable processes and that the

1 completed design meets all of the applicable regulatory
2 criteria.
3 So here is the Tricon portion of the
4 process protection system. You can see from this
5 figure which process signals are provided and which
6 functions are being performed by the Tricon subsystem.
7 The determination for function allocation to the PPS
8 subsystem were made based on the results of a Diversity
9 and Defense-in-Depth, or D3, analysis for the PPS
10 system. The licensee performed the D3 analysis early
11 in the development process and used the results to
12 enhance the system design. All functions for which
13 existing automatic diverse backup actuation signal
14 could be credited in the analysis were assigned to the
15 Tricon subsystem. That's the functions you see here.
16 There are three signals for which no
17 existing automatic diverse actuation function was
18 available for the Eagle 21 design. For these
19 functions, manual operator actions were credited or are
20 currently credited for basically maintaining plant
21 safety in the event of a failure of the Eagle 21 system.
22 All of the remaining --
23 MEMBER BROWN: Can I -- I want to make sure
24 the members understand that there were three functions
25 for which the previous design -- he said it, I'm going

to say it again -- use manual operation that were credited to meet the safety requirements. Did I state that correctly, Rich?

MR. STATTEL: That is correct.

MEMBER BROWN: Because there's a comment relative to that later, so I just wanted to --

MR. STATTEL: Now, those three functions are pressurizer pressure, containment pressure, and reactor coolant system flow. Those are the signals.

MEMBER SKILLMAN: Richard, for those three, what information does the operator have that allows that operator to make a timely action?

MR. STATTEL: They have indicators that are independent from the process protection system and isolated and diverse, and they also have alarm enunciation features. So part of the analysis was to assess whether the operator had the information he needed to make the decision to manually actuate.

MEMBER SKILLMAN: What training does the operator have to know to take that action, when that operator should take that action?

MR. SCHRADER: This is Ken Schrader from PG&E. So we do, so that operator action is a ten minute, minimum ten-minute operator action time. So this was all approved as part of the Eagle design, and

1 that is in our operator training program. So they run
2 these events on the simulator as part of the normal
3 operator training.
4 MR. STATTEL: Also, I'll mention these,
5 during our evaluation we evaluated the ability to
6 perform these operator actions. And in their existing
7 procedures today, there are steps in there for the
8 operators to read indications and direct the operators
9 to perform those manual operator actions.
10 Now, all of this, all of what we're talking
11 about here with regard to manual operator actions is
12 in relation to the existing Eagle 21 system design.
13 Some of that will change with the new system, and I'll
14 explain that as I get to that.
15 MEMBER SKILLMAN: Okay, thank you.
16 MR. STATTEL: The Eagle 21 system, I'll
17 mention, was installed in I believe 1994. The
18 evaluation was performed in 1993.
19 MEMBER SUNSERI: Just one question on the
20 training. I presume those actions are timed
21 periodically to verify they're within the time limits?
22 MR. SCHRADER: This is Ken Schrader.
23 Yes, that is correct. They are timed.
24 MR. STATTEL: Okay. So this next figure
25 is basically the equivalent diagram, but it shows how

1 the ALS subsystem or the FPGA-based subsystem fits in
2 and what functions it performs. Now you can see which
3 process signals are provided and which functions are
4 being performed by the ALS subsystem. For functions
5 associated with these signals that I mentioned before,
6 pressurizer pressure, containment pressure, and
7 reactor coolant flow, manual operator actions needed
8 to be credited in the original Eagle 21 D3 analysis.
9 Essentially, this figure also shows what the process
10 protection system functionally becomes or falls back
11 to when a total common-cause failure of the Tricon
12 system occurs.
13 MEMBER STETKAR: Rich, I don't know when
14 to ask this, and I just want to get something on the
15 record so that members can think about it. These
16 pictures are useful, but they're misleading in a sense
17 that safeguards actuation, not all safeguards, safety
18 injections are created equal. So when I went through
19 events, we found that all auxiliary feedwater actuation
20 -- you'll get to this later -- without considering AMSAC
21 or anything that's not on this picture, is processed
22 through Tricon. So anything that actuates auxiliary
23 feedwater only comes through Tricon.
24 Signals for main steam line isolation, in
25 particular for a steam line break outside containment,

1 are only processed through Tricon. Steam line break
2 inside containment you've got diversity between Tricon
3 and ALS. All signals for response to a LOCA only go
4 through ALS, and I found that kind of perspective more
5 useful than thinking about safety injection, reactor
6 trip, you know, in those kind of generic senses.
7 And I know we're going to address auxiliary
8 feedwater later. I just want people to keep those
9 other two things in the back of their heads, in
10 particular the LOCA.
11 MR. STATTEL: Just to explain these
12 figures, I created these figures based on explaining
13 the scope of our review and exactly what we're changing.
14 The perspective you're looking at, which is a lot bigger
15 than just the process protection system, really that's
16 covered with the D3 analysis. And the D3 analysis
17 basically evaluates every accident and AOO from the
18 Diablo Canyon safety analysis and evaluates what
19 functions and systems are available for mitigation or
20 addressing those scenarios.
21 MEMBER STETKAR: That's right. But as
22 the ACRS, we're interested in the whole enchilada, not
23 necessarily just the little bits and pieces of it. So
24 that's why I'm trying to keep a little bit broader
25 perspective than perhaps you might have. These are

very useful figures. I'm not trying to -- I found them really useful, but I just want to kind of alert the other members as we go through this presentation to also keep that perspective because it's the best place I could get the comment in in the flow of the presentation. I'll let you go on because of time.

MR. STATTEL: Understood. And I will mention one thing. You may notice from this figure that there are two functions that have no lines going to them. The first is a turbine trip and feedwater isolation, and the bottom one is the aux feedwater initiation.

Now, those are considered in the D3 analysis. So, essentially, those functions are lost on a Tricon failure, a complete Tricon failure. However, the D3 analysis identified for the turbine trip that the high-flux trip provides a backup safety function, which is an independent and diverse system. And for the aux feedwater, the pressurizer pressure high, the safety injection, and the high containment pressure reactor trip also perform diverse trip functions.

MEMBER STETKAR: Reactor trip, not aux feedwater actuation. We'll get to aux feedwater later.

1 MR. STATTEL: It's all in the D3 analysis.
2 Okay. Go the next slide. Okay. So I'm going to cover
3 four different topical areas that were part of our
4 evaluation. The first is communication. Our
5 evaluation of communication characteristics
6 considered all of the communication interfaces that are
7 used in the PPS application design. Communications in
8 the Diablo process protection system are used for
9 several purposes. Those include diagnostics,
10 monitoring and trending of data, set point management,
11 configuration control testing, programming. And
12 those are examples.
13 The next figure. So the PPS replacement
14 consists of four independent protection sets. This
15 figure, it's a little busy, but it does show all four
16 of those protection sets. There are no
17 inter-divisional communications being implemented in
18 this design. Therefore, the system maintains
19 divisional communication independence. There are no
20 communication links across the red lines that are shown
21 in this figure, so that means that there are no
22 communications between the Tricon and the ALS
23 subsystems, and it means that there are no
24 communications between the divisions, the four
25 protection sets that are shown on the figure. That's

1 the vertical lines.

2 Separate maintenance workstations are

3 used for the Tricon and the ALS system, and it's the

4 small boxes, so you can see that there's a MWS box in

5 each of the Tricon and ALS subsystems. And there are

6 also no communication pathways between the process

7 protection system and the solid state protection

8 system. The signals, these are the trip decisions from

9 the process protection system, are sent to the solid

10 state protection system as discrete electrical signals

11 through interposing relays. Those provide electrical

12 isolation between the PPS and the solid state

13 protection system. The solid state protection system

14 evaluates those signals and performs the coincidence

15 logic functions at the reactor trip system and ESFAS

16 levels.

17 The process protection system replacement

18 does use safety to non-safety communications. The

19 replacement architecture is designed to ensure

20 communications between safety and non-safety equipment

21 adheres to the guidance that is currently in Interim

22 Staff Guide number four, the staff positions.

23 MEMBER SKILLMAN: Richard, let me ask

24 this. Responding to your communication that the red

25 line shows solid barriers for independence between

1 Tricon and ALS and between PS-I, II, III, and IV. For
2 the maintenance workstation, very commonly, if you key
3 in and go to defeat, the other channels receive a part
4 trip or a signal that shows that the logic has been
5 changed from one or two out of four to two out of three
6 or whatever it might be. Is that same function caused
7 by deliberate status change at the maintenance
8 workstation? And if so, does it cross the red line or
9 does it come in the loading logic in the bar below?
10 MR. STATTEL: Okay. First of all, the
11 maintenance workstations are not relied upon for
12 operability of the process protection system, any of
13 the protection sets. So the maintenance workstations
14 are non-safety related devices. They don't perform
15 any safety functions. They're not required for the
16 Tricon or the ALS to perform their safety functions.
17 So, basically, that box can be disconnected, it can
18 fail, and it will not affect any of the safety functions
19 being performed by the system.
20 Where the maintenance workstation does
21 come into play is if let's say an operator wanted to
22 change set points or do testing on a Tricon system, they
23 would access that system via the maintenance
24 workstation. However, there are key switches within
25 the Tricon system that would have to be operated, which

1 would allow the maintenance workstation to communicate
2 with the Tricon processor.
3 So when those key switches are operated,
4 that's all part of the Tricon. Those would indicate
5 to the other three channels -- well, basically, those
6 would initiate an alarm to the operator that that
7 channel was out of service, and, depending on the type
8 of maintenance being done, they would either initiate
9 trips in that channel, the operators would, the
10 procedures would direct that; or they would
11 administratively declare that channel out of service
12 for testing or maintenance or whatever activity is
13 being performed. So the maintenance workstations
14 really have nothing to do with the operability of the
15 individual protection set.
16 MEMBER SKILLMAN: So just so it's clear in
17 my mind, what I heard you say is if you are accessing
18 the maintenance workstation on PS1 Tricon and you go
19 to defeat so that you can do maintenance or do a set
20 point change, you do not command a change of state on
21 any of the other three parallel sensor stations?
22 MR. STATTEL: That is correct. That is
23 correct.
24 MR. SCHRADER: This is Ken Schrader. So,
25 essentially, you get an alarm in the control room so

1 the operators would know that that protection set, you
2 know, the maintenance workstation is being used, and
3 they would then have to declare that protection set,
4 the functions that are impacted inoperable. Now,
5 we've designed it that we will be able to take, you know,
6 particular functions individually out of service so
7 that we don't affect all the functions, you know, for
8 each protection set.
9 MEMBER SKILLMAN: I'm focusing
10 specifically on the comment that Richard made relative
11 to no communication horizontally across those red
12 lines.
13 MR. STATTEL: There are absolutely no
14 communications across those lines. So let me give an
15 example. If the operator was taking a channel out of
16 service and it had some operability impacts on the other
17 three channels, then his tech specs might, for example,
18 direct him to initiate trips or force trips in that
19 channel that's being tested. So there are key switches
20 within that channel that the operator would have to,
21 basically the procedure or the tech specs would direct
22 the operator to initiate, to flip those switches and
23 initiate those trips.
24 There's nothing that automatically
25 happens. Nothing gets communicated to the other

1 channels. The only interface between channels occurs
2 at the solid state protection system, which is not being
3 modified, so those trip signals would be fed down to
4 the gray box on the bottom there, the solid state
5 protection system, so it would be comparing the four
6 channels, the decisions from the four channels.
7 MEMBER SKILLMAN: Thank you.
8 MR. STATTEL: Okay. I'll also mention
9 before I leave this slide that the horizontal lines are
10 all within the same protection set. There are no
11 regulatory requirements to have that line there. In
12 regulatory space, there's nothing that would prohibit
13 communication between the Tricon and the ALS system,
14 but, rather, this was a design decision, a conservative
15 design decision made by the licensee to not have
16 communications between those systems. And I say it's
17 conservative, and the reason for that is, by not having
18 these communications, it makes it easier for us when
19 we're evaluating this system to conclude that a failure
20 on the ALS side would not impact the safety
21 functionality of the Tricon and vice versa. So I just
22 want to mention that there's not a regulatory
23 requirement to have isolation within the same
24 protection set.
25 MEMBER STETKAR: Rich, in the interest of

1 full disclosure, because most of the members probably
2 didn't attend our subcommittee meeting and this is
3 pretty high level, some signals are transferred from
4 ALS to Tricon; is that correct?
5 MR. STATTEL: The only signals that are
6 shared between the Tricon and the ALS are the
7 temperature signals, and the reactor coolant system
8 temperatures, the RTD processing, signal processing
9 occurs in the ALS and then it is transmitted to the
10 Tricon via an analog link. It's not a communication
11 link, it's an analog signal.
12 MEMBER STETKAR: Thanks. But the term no
13 and communications means something to you that other
14 members might not necessarily appreciate.
15 MR. STATTEL: Understood, understood.
16 MEMBER STETKAR: I just want to make sure
17 people are aware that, indeed, there is a bit of talking
18 from one to the other --
19 MR. STATTEL: That is true.
20 MEMBER STETKAR: -- in that generic sense
21 of the term.
22 MEMBER BROWN: I want to, just an emphasis
23 point on that is the ALS fundamentally provides the
24 signal conditioning conversion to a 4 to 28 milliamp
25 output over to the Tricon. It's just like having

1 another RTD sending it in.

2 MEMBER STETKAR: Except it's located --

3 MEMBER BROWN: On the input part, the

4 analog input part of the ALS does that signal

5 conditioning, and it goes around the red line and into

6 the Tricon. So John is technically --

7 MEMBER STETKAR: Well, the only reason I

8 wanted to get it on the record and make people

9 appreciate it is people use words like no, which means

10 no. I mean, if you look it up in the dictionary, it

11 means no. And there is some, so, you know, I'm not

12 arguing with what the signals are, how they're

13 conditioned, and what they do.

14 MEMBER BROWN: My only point is it's not

15 computer-based serial data being transferred from

16 computer to computer. That's all.

17 MEMBER STETKAR: Which is important for

18 people who think about those things. And as I said,

19 we --

20 MEMBER BROWN: We need to keep moving here

21 if we're going to get finished, if you don't mind.

22 MR. STATTEL: One final thing I will

23 mention since we brought this up, that analog signal

24 that's shared by the ALS and Tricon system, we did

25 recognize that as a dependency. So, for example, when

1 we did our time response review, we considered the time
2 it takes for the ALS to process that signal, as well
3 as the Tricon to process it, as well. So those were
4 additive, and we considered that impact, as well.
5 Okay. So this slide really is just a
6 summary of our staff conclusion on communication, and
7 we find that it meets the guidance that is provided.
8 Move on to the next topic, control of
9 access. So this slide identifies the control of access
10 design features of the process protection system
11 replacement system. Access to the PPS will be
12 administratively controlled by control room personnel.
13 The PPS replacement design includes features that
14 provide physical access controls to the plant
15 protection system.
16 For example, the system will be located in
17 a plant vital area that can only be reached by personnel
18 with vital area access, and it will be located in locked
19 cabinets. Additionally, changing the Tricon key
20 switch, as I mentioned, to a position other than run
21 or connecting an ALS test bus connection, which is
22 essentially the equivalent of a key switch for the ALS
23 system, will cause an alarm in the control room.
24 Therefore, access to the PPS replacement is only
25 allowed to qualified personnel with permission of the

1 control room.

2 Two-way communication is only allowed

3 between the ALS and the maintenance workstation --

4 understand those are in the same cabinets -- through

5 the use of a test bus connection, which is normally

6 disconnected during operability. There is no remote

7 electronic access to the PPS subsystems. The only

8 maintenance workstations, only the maintenance

9 workstations have electronic or electronic

10 communication access to the safety system controllers.

11 The maintenance workstations are not

12 connected to any network, corporate or external.

13 Access to the maintenance workstation is to be

14 controlled by physical and logical means, and two-way

15 access from the maintenance workstations and the safety

16 processors will be restricted during plant operation.

17 Next slide.

18 CHAIRMAN BLEY: What does that mean

19 exactly? Does that mean administratively restricted?

20 You won't be allowed to do it? Does it mean some kind

21 of interlock?

22 MR. STATTEL: Oh, the physical access

23 would be the locked doors and the door accessibility

24 controls for the rooms that these cabinets are located

25 in.

1 CHAIRMAN BLEY: Got that.

2 MR. STATTEL: The logical control is via
3 password protection. So if someone wants to use a
4 maintenance workstation, they have to enter the
5 password.

6 CHAIRMAN BLEY: And you said severely
7 restricted or something like that. That's what I was
8 asking.

9 MEMBER STETKAR: So the Tricon
10 workstation is normally connected. Is there two-way
11 communication during normal operation between the
12 Tricon workstation and the Tricon platform? That's a
13 yes or no question.

14 MR. STATTEL: Yes.

15 MEMBER STETKAR: Okay. What is, what
16 parameters are communicated bidirectional? What
17 types of information is communicated bidirectionally?

18 MR. STATTEL: It's essentially plant
19 system status information and signal values, things
20 like that, things that would be used for trending and
21 data analysis.

22 MEMBER BROWN: It's not bidirectional
23 when you're in --

24 MR. STATTEL: It is -- okay. Let me
25 explain something here. It is bidirectional, but

1 please understand the maintenance workstations are
2 co-located in the same cabinet, in the same locked
3 cabinets as the PLCs and the safety processors. So in
4 order for someone to get access to the maintenance
5 workstation, they have to get into the vital area, they
6 have to get to the locked cabinet, they have to have
7 a key that's checked out from the control room operator,
8 and that's basically the barriers that they have to go
9 through to get that access.
10 MS. ALVARADO: This is Rossnyev Alvarado
11 with the NRR I&C branch. I did the review for
12 communications. I just want to clarify this. There
13 is bidirectional communication. It's possible.
14 However, during normal operation, it's just one
15 direction.
16 MEMBER BROWN: That's what I was trying to
17 get. Thank you, Rossnyev.
18 MS. ALVARADO: Right. It was from the
19 Tricon to the maintenance workstation assigned to the
20 Tricon from the ALS to the maintenance workstation
21 assigned to the ALS. For bidirectional communication
22 to occur, besides what Rich is describing, the key to
23 access that, there are also a key switch in the Tricon
24 and, therefore, the ALS, they need to connect a cable
25 that will allow bidirectional communication.

1 So during normal operation, it's not
2 possible. All the maintenance workstations are doing
3 is just collecting data.
4 MEMBER BROWN: Let me rephrase. When
5 you're in one, it's unidirectional, data going from
6 Tricon to that to collect information that can be sent
7 out to operators to trend and other stuff, but nothing
8 is going from. It's one way only --
9 MS. ALVARADO: Right.
10 MEMBER BROWN: -- in the run position. To
11 access and change that to any of the other positions,
12 you get into the space, use the key, enter the
13 passwords, and then change the specific positions of
14 the switch.
15 MS. ALVARADO: Correct.
16 MEMBER BROWN: And that's the area of
17 interest. Okay.
18 MS. ALVARADO: That's correct.
19 MEMBER BROWN: And when you go out of the
20 run position, the switch alarms in the main control
21 room.
22 MR. SCHRADER: Yes. And this is Ken
23 Schrader. And it will be declared inoperable. That
24 protection set that's being worked on is inoperable at
25 --

1 MEMBER BROWN: Well, if there's a failure
2 that made that happen and there was nobody down there.
3 But the key switch is a mechanical switch, but it
4 utilizes software to accomplish its final function, if
5 I read the --
6 MR. STATTEL: For the Tricon subsystem,
7 that is a true statement.
8 MEMBER BROWN: But it's still a switch you
9 got to turn.
10 MR. STATTEL: Yes.
11 MEMBER BROWN: And after that, it uses
12 software to establish the bidirectional, once you go
13 out of, to do the bidirectional communication. So,
14 anyways --
15 MR. STATTEL: Okay. I'll share an
16 observation that I have. So when we went out to, we
17 actually went out to witness the factory test of this
18 system. The actual program that runs on the
19 maintenance workstation, it doesn't change whether the
20 key switch is turned or not. But what you see is
21 parameters that potentially would go back to the safety
22 processors are pretty much grayed out. Basically,
23 they look different when the key switch is not turned.
24 So it's very clear to the operator that, even if you
25 went to try to change that parameter, the system would

1 not allow him to do that.

2 Once the key switch is turned and the

3 correct password is entered into the maintenance

4 workstation, then, basically, those change and they

5 become writeable fields within that program. So we did

6 observe that on both the Tricon system and for the ALS

7 during the factory test.

8 Okay. The next slide, the NRC's

9 evaluation for control of access --

10 MEMBER BROWN: Do you address external

11 plant communications later, or is that already -- I

12 thought the other point here that all external plant

13 stuff, not within a set, it goes out through a one-way

14 unidirectional --

15 MR. STATTEL: Okay. There is a

16 connection. For brevity, I had to eliminate some of

17 the previous slides. There is a connection to a

18 process plant computer system which would be the only

19 path towards external networks, external systems. And

20 for both the Tricon and the ALS, those are strict

21 one-way communications. There is no reverse path on

22 either one of those.

23 MEMBER BROWN: I just wanted to make that

24 point. That's all.

25 MR. STATTEL: Thank you. Okay. So the

1 NRC staff's evaluation for control of access is based
2 on the concept of secure development and operating
3 environment, or SDOE, and configuration management
4 also plays a large role in this. These review areas
5 were first evaluated during the topical report reviews
6 and were found acceptable. The staff found that the
7 same SDOE and configuration management measures were
8 maintained for the PPS, the Diablo Canyon application.
9 The SDOE, for SDOE, the vendors performed
10 vulnerability assessments of their facilities to
11 ensure that the replacement system is protected from
12 unauthorized access or modification throughout the
13 safety system development life cycle. The results of
14 the vulnerability assessments were used to establish
15 security control measures to mitigate the identified
16 vulnerabilities by the use of physical, logical, and
17 administrative access controls at those facilities.
18 For configuration management, the vendors
19 implemented access control measures to ensure that no
20 unintended or unauthorized functions or code could be
21 introduced into the system during development. These
22 measures included the identification of configuration
23 items such as software logic, hardware components,
24 documentation and tools, access controls based on work
25 responsibilities of the individuals performing the

activities, change review approval and verification process, and error reporting and corrective actions program. To detect and prevent the introduction of unintended or unauthorized changes to the code, the vendors V&V, verification and validation groups, performed code reviews, as well.

And, finally, this slide summarize our conclusions. We concluded that the replacement design incorporates features to administratively, physically, and logically control access to the system both during development and during operation. These features meet the guidance for secure development and operation environment and configuration management. Therefore, the NRC staff determined that the PPS system meets the criteria for control of access.

Now, once the system is installed into the plant, it is our expectation that the system would also be incorporated into the cybersecurity program at Diablo Canyon. It would be identified as a critical digital asset, and the operational measures required for the cybersecurity program would be implemented at that time. But that's not part of the system evaluation.

Okay. The next slide. Okay. The next topic is Diversity and Defense-in-Depth, which we've

1 already touched on. The NRC requires a coping strategy
2 be developed for digital safety systems to address the
3 effects of software common-cause failures when the
4 potential for CCF cannot be eliminated.
5 D3 analysis was initially performed for
6 the Eagle 21 system back in 1993. This analysis
7 postulated a software common-cause failure resulting
8 in the failure of all PPS functions to actuate.
9 For functions associated with those three
10 that I mentioned earlier, containment pressure,
11 reactor coolant system flow, and pressurizer pressure,
12 the analysis credited manual operator actions as a
13 means of coping. This modification will eliminate the
14 reliance on those manual operator actions for coping
15 with those, the CCF.
16 The licensee performed the D3 analysis to
17 address the upgrade. The new D3 analysis was
18 essentially an update to the previous Eagle 21 analysis
19 tables. It involved postulation of software CCFs for
20 all plant accidents and AOOs described in the FSAR
21 safety analysis. And as you have seen in previous
22 slides, the safety functions associated with these
23 parameters have been allocated, the three parameters
24 I mentioned have been allocated to the ALS portion of
25 the process protection system.

1 The D3 analysis does not make a case that
2 software CCF of either the Tricon or the ALS is not
3 possible. Instead, it determined that the effect of
4 the postulated CCF for the ALS subsystem does not cause
5 a loss of those safety functions.
6 So the Tricon -- I have one slide for Tricon
7 and the other for ALS. The Tricon system, as the name
8 implies, contains three separate layers of redundant
9 input, processing, and output components for each of
10 the protection sets. In a sense, this establishes 12
11 levels of redundancy for the Tricon subsystem.
12 All of this redundancy is expected to
13 result in a highly-reliable and fault-tolerant system.
14 These characteristics were evident to the staff when
15 we reviewed the failure modes and effect analysis and
16 the reliability analysis documents.
17 I would expect to see a very small amount
18 of LCO time due to system maintenance and surveillance
19 testing following this upgrade. These system
20 characteristics, however, do not address the issue of
21 software common-cause common-mode error because all of
22 the redundant processors within the Tricon will be
23 executing common software components.
24 As a result, the PPS D3 analysis
25 postulates, just like the Eagle 21, it postulates a

complete failure of all of the functions performed by the Tricon subsystem and identifies alternate means of maintaining reactor safety for each of the events analyzed. This updated D3 analysis was performed prior to the LAR submittal, and the NRC did a separate evaluation of that document.

Okay. Next, we go over to the ALS system. Now, the ALS subsystem, on the other hand, is designed with two important diversity features that were considered in the NRC evaluation. They are listed here: core diversity and embedded design diversity.

Now, there are proprietary aspects of each of these functions that I won't be able to get into today. We did discuss some of those at the subcommittee meeting.

MEMBER BROWN: Rich, can you just emphasize that the ALS is not a microprocessor-based system but a FPGA, Field Programmable Gate Array, type system?

MR. STATTEL: Okay. The ALS is not a microprocessor.

MEMBER BROWN: I want you to say it, not me, okay?

MR. STATTEL: It is not a microprocessor-based system. It's a Field

1 Programmable Gate Array System. Now, that's not to say
2 that there's no software involved in the development
3 of such a system, but the development of that logic uses
4 software tools. However, once the logic is developed
5 and downloaded into the FPGA chip, there are no clocks
6 or processors or interrupts or any type of processing
7 that gets performed during operation of that system.
8 So it's a fundamental difference between the PLC, the
9 Tricon type PLC operation and the ALS system operation.
10 Okay. So core diversity as implemented in
11 the Diablo Canyon application generates two redundant
12 logic implementations for placement within each FPGA
13 for each standardized circuit board. Embedded design
14 diversity provides an additional level of diversity.
15 Embedded design diversity requires the production of
16 two versions of the logic files for each standardized
17 circuit board.
18 The Diablo Canyon application defines the
19 configuration and arrangement of the PPS system and
20 creates two different sets of FPGA design variants. A
21 really important point I want everyone to understand
22 is the design variants, there's an A variant and a B
23 variant, they're housed in separate chassis. So there
24 are two ALS chassis within each protection set of the
25 process protection system.

1 Okay. So the new system design will
2 eliminate the need to perform manual operator actions
3 as a means of coping with the software CCF of the PPS.
4 However, the modification does not affect the ability
5 of operators to perform manual operator actions of
6 safety functions. So the existing component, and we
7 verified this during our evaluation, the existing
8 component and division-level actuation capability is
9 being retained, and these capabilities will not be
10 changed as a result of the PPS upgrade.
11 We asked the licensee, for example, what
12 procedurally would we expect the operator to do
13 differently once the new system is installed. And in
14 this area, there is no difference. So the indicators
15 are still diverse, the indicators that we talked about
16 earlier. The alarms and indications the operator has
17 available to him are still going to be available to him,
18 and they will still be diverse from the process
19 protection system. And the procedures will still
20 direct the operator to perform the manual initiations
21 when the conditions indicate that.
22 However, the ALS system contains enough
23 diversity where we do not expect any common-cause
24 failure of a software nature to affect or to impact the
25 safety functionality of the system. So there

1 shouldn't be any need for the operator to do it, but
2 he still has the ability to do that and the procedures
3 will still direct him to take those actions.
4 MEMBER STETKAR: Rich, I wanted you to get
5 through all of that before I asked you this. If I have
6 a steam line break downstream of the main steam
7 isolation valves and I have software failure in the
8 Tricon platform, do I need operator actions to close
9 the MSIVs? That is a yes or a no answer I'm looking
10 for.
11 MR. STATTEL: Operator action to close the
12 MSIVs. I would have to research that.
13 MR. SCHRADER: The answer is no. You
14 would get an actuation from the AMSAC system, which is
15 separate and independent.
16 MEMBER STETKAR: I'm sorry. AMSAC has
17 nothing to do with isolating the main steam line. It
18 trips the turbine. I'm asking do I get a main steam
19 line isolation signal if I have a steam line break
20 downstream of the MSIVs and software failure in the
21 Tricon platform?
22 We've asked this question since, my notes
23 are February 18th, 2014. I've asked it several times.
24 Every time, I get the answer, oh, yes, in that
25 particular instance, the operators would need to

1 manually close the MSIVs. It does not dispute any of
2 the things that are on this slide. It just says that
3 there may be some things that still require manual
4 action. So I'm taking issue with these words, these
5 absolute words like no, eliminate, absolute
6 statements.
7 And I've asked this question several
8 times, and every time I've always cast the three things
9 that I started out with. LOCAs, I understand you're
10 taking credit for the core diversity within ALS to
11 provide diverse signals. I understand how AMSAC is
12 providing a diverse signal to start auxiliary
13 feedwater. I have never been able to have anybody
14 explain to me if I have a software failure in the Tricon
15 platform and a steam line break downstream, it's got
16 to be downstream, not upstream, of the MSIVs, whether
17 or not I have to have operator actions. And the last
18 answer that I have in my notes is, yes, for that
19 particular incidence, we need operator actions to close
20 the MSIVs; however, all of the other things that you
21 have on this slide do apply. They can still close the
22 MSIVs directly from the switches on the main control
23 board through the SSPS logic and that they're trained
24 to do that because they have to do that, you know,
25 currently, with the Eagle 21 stuff.

1 MR. STATTEL: I'd like to qualify the
2 words on the slide and our statements with regard to
3 manual operator actions. We are in no way claiming
4 that there will be no reliance by the plant on manual
5 operator actions. However -- for all events.
6 However, when we take a common-cause failure of the
7 Tricon system or the common-cause failure of the ALS
8 system, those do not require manual operator actions,
9 and there are mitigating functions that are existing
10 and identified in the D3 analysis for those.
11 MEMBER STETKAR: If you can find. I'd
12 really appreciate it because we are writing a letter
13 on this.
14 MR. STATTEL: I understand.
15 MEMBER STETKAR: And if you can find for
16 me sometime today in realtime how manual operator
17 actions are not required, in particular for a steam line
18 break downstream of the MSIVs with common-cause failure
19 of the Tricon platform. I'd really like to know how
20 that is achieved, you know, why the operator actions
21 to isolate the main steam line is not required.
22 MR. STATTEL: In fairness, you have asked
23 similar questions in the past, but the scenarios always
24 vary a little bit. The last time we spoke of this, you
25 were questioning whether the AMSAC would be able to --

1 MEMBER STETKAR: Rich, Rich, I'm sorry.
2 I thought I was clear. If you look at today's
3 transcript, I've said that there are three events. I
4 said auxiliary feedwater actuation given a software
5 failure with a successful reactor trip, software
6 failure in Tricon. I know that that is addressed by
7 AMSAC. I've asked about main steam line isolation
8 given a steam line break downstream of the MSIVs with
9 a software failure in the Tricon platform. That has
10 never been addressed except to say that we need operator
11 actions to do that. And I've asked LOCAs, given
12 whatever protection through ALS. And that has not
13 varied. I'm looking at printed notes, and I'm pretty
14 good about keeping notes, from February 18th, 2014.
15 You can look up the transcripts. I don't vary, so don't
16 --
17 MR. STATTEL: Okay. I understand that.
18 We do have the answer to that. It is in the D3 analysis.
19 It would be very quick for me to look that up.
20 MEMBER STETKAR: My notes are from
21 comments on the D3 analysis. The meeting we had on
22 February 18th, 2014 was specifically on the safety
23 evaluation of the D3 analysis itself. That's when my
24 notes started on this. That's when I asked the
25 question first when we were looking at the D3 analysis.

1 So I don't want to take up more time,
2 Charlie. I've got it on the record. If, indeed, there
3 is something and we can quickly, you know, get access
4 to that, that would be great because we have follow-on
5 discussions and I understand how AMSAC works now for
6 auxiliary feedwater.
7 MR. WATERS: We'll do our best to get you
8 a response and point to the D3 analysis if we can.
9 MEMBER BROWN: I want to just make sure I
10 understand one thing. In the Eagle 21 system, you
11 assume Eagle 21 failed totally, and that operated the
12 main steam, that had a signal going for main steam --
13 MR. STATTEL: That is one of the signal's
14 process --
15 MEMBER BROWN: -- main steam isolation,
16 okay, in Eagle 21. And if you lost that, it had to be
17 manually isolated; isn't that correct?
18 MR. STATTEL: Or other mitigating means of
19 maintaining plant protection.
20 MEMBER BROWN: That would have been
21 another diverse means of some sort.
22 MR. STATTEL: Right, which there are many,
23 yes.
24 MEMBER BROWN: All I'm trying to do is put
25 a, I'm just trying to calibrate myself relative to Eagle

1 21 goes away, it had no capability to isolate main steam
2 isolation valves, so there was some other means,
3 whatever it was, today that has to be done to do that
4 under those circumstances, a main steam line break.
5 When I'll look at the ALS and Tricon
6 functions, the main steam isolation valve, based on the
7 previous discussions, it's shown as being activated by
8 both the ALS and the Tricon system.
9 MEMBER STETKAR: If you look at the signal
10 process, and, again, for the record, that is
11 specifically for a steam line break inside the
12 containment where you can take credit for a
13 high-containment pressure to close the main steam
14 isolation valves as a diverse signal from the low steam
15 line pressure. So for -- that's why I'm very careful
16 about saying steam line breaks down --
17 MEMBER BROWN: You kind of lost the
18 bubble.
19 MEMBER STETKAR: I understand that. It's
20 on the record.
21 MEMBER BROWN: I'm not interested in what
22 the record says. You said inside vice outside. Does
23 the steam lines go outside the containment?
24 MR. STATTEL: They go inside and outside.
25 MEMBER STETKAR: Well, yes, they start

1 inside the containment. They go out to the turbine,
2 which is outside the containment.
3 MEMBER BROWN: Okay, I got it. So you're
4 talking about downstream of the isolation valves?
5 MEMBER STETKAR: That's what I was saying.
6 MEMBER BROWN: Is it strictly a pressure
7 signal in the containment that initiates that isolation
8 function?
9 MEMBER STETKAR: You get low steam line
10 pressure or high containment pressure isolates the
11 steam line.
12 MEMBER BROWN: Okay. Well, is the
13 pressure different whether it's outside or inside --
14 MEMBER STETKAR: If it's outside, if it's
15 outside, the steam is going outside the containment,
16 so the containment pressure doesn't increase. The
17 steam is going into the turbine building --
18 MEMBER BROWN: But the steam pressure goes
19 down.
20 MEMBER STETKAR: That's right, but the
21 steam pressure is processed only through Tricon.
22 That's all right.
23 MEMBER MARCH-LEUBA: The containment
24 pressure only goes to A.
25 MEMBER BROWN: Yes, I got that.

1 MEMBER MARCH-LEUBA: And the steam line
2 pressure only goes to T. If you have a break outside
3 of the containment, A doesn't get any signal because
4 the containment pressure doesn't change.
5 MEMBER BROWN: Okay. I got your point
6 now. All right. What I'm trying to get to, is this
7 different than what is just today?
8 MEMBER STETKAR: My sense is no, quite
9 honestly. Let me go back to where I am now. It's not
10 different because the operators, I believe, would need
11 to manually isolate the steam line right now. All I'm
12 doing is trying to alert, get something on the record
13 and alert the other members that statements like
14 "eliminates the need for manual operator action" is not
15 --
16 MEMBER BROWN: Is almost true.
17 MEMBER STETKAR: Is almost true. It
18 eliminates several of the operator actions that are
19 currently required under Eagle 21. The only one that
20 I could come up with that it didn't is this particular
21 one. Is that important? You know, I'm not going to
22 make a value judgment.
23 MEMBER BROWN: Is this one of the three
24 credited items from before?
25 MEMBER STETKAR: No, no, it isn't.

1 MEMBER BROWN: I'm just trying to be
2 clear. The three credited items from before are the
3 manual operations are still capable. I mean, you could
4 still do them, they're not eliminated. However, they
5 are performed by the new systems, whereas they weren't
6 before. The steam line isolation function was not done
7 before, and it is not done afterwards.
8 I'm trying to get the calibration here is
9 that the PPS system does not improve that situation any,
10 but it's not a change from what exists today. So we
11 can work on the nuances of the words all we want. I
12 just want to make sure the changes that are being made
13 don't change the fundamental basis for plant operation
14 today, and I want that on the record. Is that clear?
15 Okay. Let's go on. Thank you.
16 MR. STATTEL: Okay. The final slide is
17 the safety conclusions regarding D3 that were reached
18 by the staff.
19 Okay. The next topic is system time
20 response and deterministic performance. So our review
21 guidance states that the evaluation should confirm the
22 system's realtime performance characteristics, are
23 deterministic and known. It identifies design
24 practices to be avoided for computer-based systems.
25 These practices include non-deterministic data

1 communications, non-deterministic computations,
2 interrupts, multitasking, dynamic scheduling, and
3 event-driven design.
4 The staff evaluated the deterministic
5 behavior characteristics for each subsystem within the
6 context of the Diablo Canyon application, input and
7 output signal processing, time response and
8 predictability of performance, data transfer methods
9 - both platforms transfer data between processing and
10 input and output modules through a backplane
11 communication path -- software or logic implementation
12 structure including the operating system for the Tricon
13 system, and system diagnostic functions.
14 Next slide. So for ALS, the ALS platform
15 is an FPGA-based design, and it does not embed
16 microprocessor cores or use interrupts in any way. The
17 staff has confirmed that the Diablo Canyon application
18 of the ALS platform operates on fixed cycles where
19 deterministic sequence of acquire inputs perform a
20 logic operation, such as compare a process variable
21 with a trip set point, and to determine partial trip
22 status, and, three, generate outputs as followed
23 without use of a microprocessor core or interrupt.
24 This is consistent with the ALS platforms
25 approved in the topical report. I will mention there

are parameters which are application specific, and those required additional staff evaluation during our amendment review.

Next, over the Tricon system, the Tricon system triple redundant architecture is designed so that input signal processing, application function performance, and output signal processing are performed by redundant sets of components that operate asynchronously in parallel. And that's done to provide a highly-reliable safety function.

The Tricon uses a custom system executive to run processor card and host the safety application. The system executive is an operating system used to cyclically run tasks. The tasks are prioritized and interrupts are used to assess, to assert this priority.

Deterministic behavior for the Tricon is assured through the synchronizing of application scans, which guarantees a new set of inputs, a new set of outputs for the IO modules are established during each and every application scan in each of the separate processors. There are no event-based interrupts used in the Tricon design.

Okay. Based on the specification analysis, deterministics performance characteristics and system response time performance test results, the

1 NRC staff determined that the Diablo Canyon PPS system
2 meets all of the requirements for system response time
3 performance and deterministic behavior. This is the
4 safety conclusion reached by the staff.
5 Okay. Now we'll switch gears a little
6 bit. I'm going to refer back to the April 4th meeting.
7 So on April 4th of this year, we presented the license
8 amendment evaluation to the Digital I&C Steering
9 Committee. The staff at the time had completed it
10 safety evaluation and provided its technical input to
11 the project manager. However, there were two
12 remaining open items both pertaining to the seismic
13 qualification of the installed systems. One was for
14 the Tricon, and the other was for ALS.
15 Next slide. Okay, you got it, you got it.
16 Okay. The open items were to establish seismic
17 profiles for the location, for the local installation
18 sites for both the Tricon and the ALS equipment and to
19 confirm that the established equipment qualification
20 levels were sufficient to bound the in-equipment
21 response spectra at the installation sites.
22 So think of it this way: we knew from our
23 platform reviews exactly what kind of accelerations and
24 what kind of seismic environment the equipment was
25 tested to and was qualified to. What our job at the

application level was to make sure at the installation site, specifically the location within the cabinet, that the maximum seismic levels at that location would not exceed those qualification levels. And in most cases, that's not too difficult to do because the seismic information for a room is very well documented in a safety analysis report. However, since we're not bringing a cabinet in, we're basically installing components within existing cabinets, we didn't have the exact seismic data for those very detailed locations. And so a calculation had to be done. The licensee performed this seismic calculation, and it established the in-equipment response spectrum for the installation sites, and the NRC has now confirmed that the PPS equipment is seismically qualified for installation and operation at those locations.

And this resolution here shows our conclusion. So there are no open items in this safety evaluation.

Okay. Now, during that same meeting, there were --

MEMBER SKILLMAN: Wait a minute here. Back to Yosemite Sam, not so fast there, partner. That is not a simple calculation. When you've got a cabinet, when you install new racks within a cabinet,

1 and you install new devices on those racks within that
2 cabinet, you can set up new residences, new frequency
3 exchanges between the rack locations. Speak to us,
4 please, about the thoroughness of the calculation.
5 The gentleman from Diablo said, oh, by the way, we put
6 in strengtheners, so there was something that showed
7 stiffeners were required, obviously, to increase the
8 natural frequency. So speak to this from the
9 perspective here's how we know the calc demonstrated
10 that the IERS is bounding the TRS.
11 MR. STATTEL: All right. You are
12 absolutely correct. I really don't want to make light
13 of this calculation because it was a difficult thing
14 to get. The NRC first asked this question early in our
15 evaluation about four years ago, and, at the time, the
16 design had not been completed. So, for example, we
17 knew what equipment was going to be part of the design.
18 We didn't know the actual mounting locations within the
19 cabinet, and, in some cases, we didn't know what
20 equipment was in which cabinet, and that's critical
21 information for determining the in-equipment response
22 spectrum.
23 So this calculation was not an easy
24 calculation for them to perform. They did it over the
25 course of a couple of years. It identified

1 shortcomings in those cabinets. So the weights of the
2 chassis being installed in those cabinets were factored
3 in. They also performed tests in the field, and, now,
4 understand these cabinets have the Eagle 21 equipment
5 installed, but they perform a test called a ping test
6 which identifies residences within the cabinet. And
7 that data went into this calculation. The mounting
8 locations were clearly identified in the design. They
9 did finalize that and included that information in the
10 calc.
11 The calc includes separate calculations
12 for each of the protection sets because, even though
13 there's a lot of similarities between the protection
14 sets, there are design differences. And it also
15 identified shortcomings in those cabinets, and the
16 calculation identifies new bracing that had to be
17 installed in those cabinets to basically make them more
18 resilient or change the response characteristics in
19 those cabinets.
20 The calculation itself, I reviewed it
21 myself. I'm not a seismic or a civil engineer, so I
22 also had our seismic and civil engineers review those
23 results, and it identified several in-equipment
24 response spectrums. So, basically, these are the
25 response spectrums for two different types of

1 earthquakes. It includes the design basis earthquake
2 and the double-design basis earthquake. It includes
3 the -- what was the other -- okay, yes. And it
4 basically defines what the expected actual
5 acceleration levels are, vertical, horizontal, and
6 it's X, Y, and Z, basically, on three axis. And it's
7 superimposed the qualification levels from our
8 platform, so basically from our platform tests. Those
9 spectrum are superimposed over those calculated
10 spectrum, and it shows that it's enveloped in all
11 frequency levels.
12 So it is a very detailed calculation. We
13 did insist upon that. I will mention that the, there
14 were some limitations to the testing that could be
15 performed. So at the very low frequency levels,
16 basically it takes a lot of energy to move equipment
17 of a certain mass up to high g-force levels. And
18 there's a lot of equipment that basically is just not
19 capable of doing that. We did look at that, as well,
20 and the licensee provided justification for those
21 qualifications that were established.
22 MEMBER SKILLMAN: Should we assume that
23 those are calculations of record, and they are in your
24 Appendix B, the 10 CFR 50 covered by Criterion 3 and
25 Criterion 16?

1 MR. SCHRADER: Yes, this is Ken Schrader
2 from PG&E. Yes, that's correct. These calculations
3 -- well, let me just say that the calculations we have
4 right now are based on, essentially, the draft design.
5 Once the design is completely finalized and we have the
6 as-built drawings, you know, for the cabinets and the
7 equipment where you go out and you measure actually all
8 of the geometry, we will then finalize that
9 calculation, and then that final calculation -- and
10 that is done under Appendix B because it's a
11 safety-related equipment -- that will become part of
12 the plant design documentation.
13 MEMBER SKILLMAN: Thank you.
14 MR. STATTEL: Okay. So at the April
15 meeting, there were several comments that were provided
16 to us regarding the safety evaluation, and we discussed
17 several topics. I'm prepared to discuss, I have them
18 listed here, I'm prepared to discuss each of these
19 comments and explain how the staff has resolved these,
20 if you wish. We did provide a response for each of
21 these areas in writing to the subcommittee, I believe.
22 Okay. The next slide, it's back to
23 Balwant.
24 MR. SINGAL: This is Balwant Singal again.
25 The purpose of this slide is just to show you the

1 schedule going forward. We're basically assuming that
2 we'll have the ACRS full committee letter hopefully by
3 the end of the month and then finalize the package and
4 copy all the comments and recommendations by end of
5 October and go through conference with all the
6 technical staff and general counsel and try to get you
7 the package before end of the year.
8 MR. LUBINSKI: And if I can, this is John
9 Lubinski. In the interest of time and speaking about
10 our presentation, this concludes the part of our
11 presentation with respect to the Diablo license
12 amendment request. So with the remaining time, I'd
13 like to turn it to ACRS to ask any additional questions.
14 CHAIRMAN BLEY: I'm going to beat a dead
15 horse. I had time to go back and look at your review
16 of the D3 analysis, and they looked at steam line break
17 events, but, from all the texts, you were looking at
18 steam line breaks inside the containment, counting on
19 the reverse flow protection to keep the other
20 generators from blowing back down into containment.
21 If it's outside of containment, that doesn't work, so
22 I don't think you looked at outside containment.
23 MEMBER STETKAR: Just to get more stuff on
24 the record regarding that, we did get feedback from the
25 staff in our April 4th subcommittee meeting of this year

1 that my notes say the staff provided a written summary
2 response which confirms that an automatic steam line
3 isolation actuation signal will not occur for steam
4 line breaks outside the containment coincident with
5 software common-cause failures in the Tricon platform.
6 I'm quoting now from my notes, so just to make that
7 clear.
8 The summary indicates that Diablo Canyon
9 has examined the effects from that steam line break
10 without steam line isolation. That analysis was
11 prompted by a different concern, but it would apply for
12 this situation. It concluded that the SFAR accident
13 analyses for a blow down of a single steam generator
14 through a ruptured steam line between the containment
15 and the MSIV, so you're going to blow down that one steam
16 generator, just one, outside of containment are more
17 limiting for DMV due to the asymmetric effects on core
18 power.
19 So they essentially made an argument that
20 said the more limiting SFAR accident analysis for a
21 single steam line break outside containment upstream
22 from the MSIV in terms of DNB was more limiting than
23 a steam line break downstream with no steam line
24 isolation because that would have symmetric effects on
25 the core.

1 Those are my notes. That's the feedback
2 that we got in April regarding this thing. They did,
3 in fact, confirm that manual steam line isolation would
4 be needed but that, from an SFAR design basis accident
5 core response, this other event is apparently limiting.
6 I didn't follow up on that particular accident but just
7 to kind of close the loop a little bit more on that.
8 MR. SCHRADER: Yes, I can just confirm.
9 This is Ken Schrader. That was the information that
10 we got from the vendor of Westinghouse. We went back
11 to them after the meeting and got that information,
12 essentially, for DNB, the scenario you're asking about,
13 the steam line break outside containment is a
14 non-limiting event for the criteria that you do the
15 accident analysis for all the different types of main
16 steam line breaks that could occur.
17 MEMBER BROWN: And I'll presume that that
18 does not change for whether you've got Eagle 21 or the
19 PPS?
20 MR. SCHRADER: Yes, that's correct.
21 Eagle 21 right now does not --
22 MEMBER BROWN: It's got the same issues --
23 MR. SCHRADER: -- a steam line, sorry,
24 isolation and neither will the new system.
25 MEMBER BROWN: Okay. I just wanted to

1 make sure.

2 MR. SCHRADER: But it's a non-limiting

3 event.

4 MEMBER BROWN: Okay, thank you. John,

5 unless you have something else, we're needed to wrap

6 it up by 12:15.

7 MEMBER STETKAR: I don't have anything

8 more. Thanks.

9 MEMBER BROWN: Okay. Are there any other

10 comments from the members right now? Then I will turn

11 it back over to you, Dennis.

12 CHAIRMAN BLEY: You need to get some

13 public comments first, Charlie.

14 MEMBER BROWN: Oh, I forgot about that.

15 Excuse me. Christina, can you -- is there anybody in

16 the room? Can you go check the phone line? Is there

17 anybody in the room? I don't see any. There's not

18 enough spectators to worry about that, I guess. Is it

19 open? Is anybody on the line? Can you say something?

20 MS. TILTON: Yes, this is Caroline Tilton

21 from the Tech Spec Branch.

22 MEMBER BROWN: Do you have any comments?

23 MS. TILTON: I do not have any comments.

24 Thank you.

25 MEMBER BROWN: Okay. Anyone else?

1 Well, thank you very much. We will close the line,
2 Christina, and now we'll turn it back over to you.
3 CHAIRMAN BLEY: Thank you very much,
4 Charlie. Right on time. Perfect.
5 MEMBER BROWN: That's the way we work in
6 the instrumentation and control world.
7 CHAIRMAN BLEY: We will recess until 1:30
8 when we'll return to talk about Fermi 2.
9 (Whereupon, the above-entitled matter
10 went off the record at 12:15 p.m. and resumed at 1:29
11 p.m.)
12 CHAIRMAN BLEY: The meeting will please
13 come to order. We are about to move to our last topic
14 of the day, I guess. I'll turn it over to Mr. Skillman.
15 MEMBER SKILLMAN: Ladies and gentlemen,
16 good afternoon.
17 This is a meeting on the Fermi 2 Nuclear
18 Power Plant License Renewal Review. This is Agenda
19 Item 4.
20 And, this afternoon, we will hear
21 presentations from the Division of License Renewal, the
22 applicant, DTE Electric Company.
23 And, this meeting is being conducted in
24 accordance with the provisions of the Federal Advisory
25 Committee Act. And, Mr. Kent Howard is the Designated

1 Federal Official for this portion of the meeting.
2 We come here today after years of toil by
3 the Detroit team. And, I will call upon Ben Beasley
4 to please introduce his team and to start this process.
5 Ben, thank you.
6 MR. BEASLEY: Thank you, Mr. Skillman.
7 Thank you Chairman Bley and Members of the ACRS.
8 I am the Acting Deputy Director for the
9 Division of License Renewal in NRR.
10 With me at the table is Yoira
11 Diaz-Sanabria. She is Branch Chief of Projects,
12 Branch 1, which is responsible for the safety reviews
13 of license renewal applications.
14 Presenting for the NRC today will be Lois
15 James, the License Renewal Safety Project Manager for
16 Fermi 2.
17 Also in the audience are the technical
18 review branch chiefs from the Division of License
19 Renewal, Dennis Morey and Brian Wittick.
20 Dennis is Chief of the Aging Management of
21 Reactor Systems Branch. And, Brian is Chief of the
22 Aging Management of Structures, Electrical and Systems
23 Branch.
24 We also have members from the Division's
25 Technical Review team in the audience and on the phone.

1 So, I have good hope of answering your questions, most
2 of your questions, today.
3 During the Subcommittee meeting in March,
4 we discussed one open item in the Safety Evaluation
5 Report with Open Items. This open item has since been
6 closed and the staff will be discussing their
7 resolution during our presentation.
8 We look forward to a productive discussion
9 today when we present our report on Fermi 2.
10 But, at this time, I will turn the
11 presentation over the DTE Energy Company and Site Vice
12 President, Keith Polson, to introduce his team and
13 commence their presentation.
14 MR. POLSON: I'd just like to start out,
15 first of all --
16 MEMBER STETKAR: Turn -- there's a little
17 thing closest to you that says, push.
18 MR. POLSON: Okay, let's try that again.
19 First of all, we appreciate the
20 opportunity to come here and present the overview of
21 the Fermi Plant and our license renewal project to the
22 Full Committee.
23 As stated earlier, there's been a lot of
24 hard work that's gone into this, all parties that were
25 involved in submission of the application.

1 But, I do believe it's a very high quality
2 product.
3 But, with that said, we also recognize that
4 there's a lot more to do.
5 So, moving on, I'd like to introduce my
6 team. I'm Keith Polson, the Site Vice President at
7 Fermi 2.
8 To the left of me is Larry Peterson who's
9 the Director of Engineering. To the left of him is Lynn
10 Goodman, the License Renewal Project Manager. And --
11 sorry, I skipped Randy. And, Randy Breymaier, Manager
12 of Performance Engineering.
13 We also have a lot of people in the -- in
14 back seats. They are subject matter experts that we've
15 brought along. They represent various departments at
16 the plant and some people from outside engineering
17 firms.
18 Some of the departments that they
19 represent are Operations, Engineering, Projects,
20 Licensing and, actually, we have some of the program
21 owners that we'll talk about later.
22 It wasn't my intent to introduce all of
23 them, but I'd just like to recognize that they're here.
24 So, moving on to the agenda, that was the
25 introduction portion. Larry's going to talk about the

1 plant design, plant history and the current status.
2 And, then, Lynn's going to talk about the
3 license renewal application project and the closed SER
4 open item that we had last time when we presented to
5 the Subcommittee.
6 Then, Randy's going to talk about aging
7 management programs. And, then, I'll give closing
8 remarks.
9 So, with that, Larry?
10 MR. PETERSON: Thanks, Keith.
11 Next slide, please?
12 Fermi's a 3486 megawatt thermal boiling
13 water reactor and electrical output of approximately
14 of 1170 megawatts.
15 It is a GE BWR 4 with a Mark 1 containment.
16 We do share a site with Fermi 1 fast breeder reactor
17 which is currently in passive safe store.
18 Next slide, please?
19 This slide has an aerial view of the site
20 with some of the highlighted buildings. I want to draw
21 attention to a couple of specific design features.
22 We do take suction off of Lake Erie for our
23 general service water which is down in the southeast
24 corner of the overhead. That cools a number of
25 components and discharges into the cooling water pond

1 or circ water reservoir, I'm sorry.

2 The circ water reservoir, we also have two

3 natural draft cooling towers which are up on the north

4 end of the site.

5 The RHR complex, which is right in the

6 center of the picture just to the west of the reactor

7 building, that complex is our ultimate heat sink.

8 We'll actually have two designated reservoirs for our

9 ultimate heat sink, one per division. And, it includes

10 two mechanical draft cooling towers for those

11 reservoirs.

12 That RHR complex also houses our four

13 emergency diesel generators.

14 Electrical design down in the very

15 southeast corner of the site is our Division 1

16 switchyard, 120 kV switchyard.

17 And, to the west of the site is our Division

18 2 switchyard.

19 We have two separate switchyards for both

20 divisional power sources. And, as noted before, we

21 have four emergency diesel generators, two per

22 division.

23 We also have a combustion turbine

24 generator with is our station blackout power supply.

25 Next slide, please?

1 Our operating license, we received in
2 March of 1985 and we achieved commercial operation in
3 January of 1988.
4 We've done two power uprates. We've done
5 a 4.2 percent increase in September of '92 and a 1.64
6 percent measurement uncertainty recapture in February
7 of 2014.
8 We implemented our first ISFSI campaign in
9 2014. You'll note up in the picture, up in the upper
10 right is one of our components, vertical cask
11 transporter use for our ISFSI campaigns.
12 We also implemented our FLEX strategies
13 and our spent fuel pool coming out of our fall 2015
14 refueling outage. The building shown in the bottom is
15 one of out FLEX storage facilities.
16 Next slide, please?
17 In anticipation of extended operation,
18 we've looked at the --
19 MEMBER SKILLMAN: Larry, please back up
20 one.
21 MR. PETERSON: Yes.
22 MEMBER SKILLMAN: You said on image, the
23 image on slide nine at the bottom is one of your FLEX
24 storage facilities.
25 MR. PETERSON: Yes.

1 MEMBER SKILLMAN: How many do you have and
2 why?
3 MR. PETERSON: We have two. Can you back
4 up to that slide, please?
5 If you look just near the cooling towers
6 FLEX storage facility number two and then, closer to
7 the reactor building is FLEX storage facility number
8 one.
9 Our FLEX strategy takes suction off our
10 circ water pond and both FLEX storage facilities have
11 both N and N+1 equipment to be able to take that suction
12 off the circ water pond and ultimately discharge into
13 penetrations in the reactor building.
14 MEMBER SKILLMAN: Thank you.
15 MR. PETERSON: As I was saying, the DTE
16 Energy is making a large investment to ensure that we
17 have safe, reliable operations through the 2045 in
18 anticipation of license renewal.
19 It includes generator replacement,
20 replacement of a variety of pumps and motors, process
21 computer replacements, the FLEX implementation that I
22 mentioned prior -- previously, hardened vent
23 implementation to meet the hardened vent order, spent
24 fuel racks and, as Lynn and Randy will be talking about,
25 establishment of all of our aging management programs

1 to be able to meet there requirements for license
2 renewal.
3 Other plant modifications for safe
4 extended operations are part of normal process for
5 consideration.
6 If there's no questions, I'll turn it over
7 to Lynn.
8 Lynn?
9 MS. GOODMAN: Hello, my name is Lynn
10 Goodman.
11 Next, please?
12 I'll be talking about our application. We
13 submitted our application in April 2014. It is based
14 on GALL Rev 2. And, in it, we identified the aging
15 management programs that we are using and will be using
16 to manage aging effects during the period of extended
17 operation.
18 In developing our application, we used
19 both our own experience and we also used industry
20 operating experience from our peers.
21 Our subject matter experts and our
22 management were involved with the application
23 development, review and oversight.
24 We used Enercon/Entergy as our experienced
25 LRA contractor to help us.

1 After our application was mainly written,
2 we did have Interim Staff Guidance Document 2012-02
3 come out. And, then, since then, we've also had
4 2013-01 which is on coatings and 2015-01 which is on
5 buried pipe. And, we've addressed all of those in
6 either our original applications or in supplements --
7 supplemental submittals to address those specific
8 Interim Staff Guidance Documents.
9 Next?
10 We had one open item in our SER with Open
11 Items, and that was on the effects of reactor water
12 environment on fatigue life and has since been closed
13 in the final SER.
14 And, what the issue was, was that the NRC
15 staff questioned how average temperatures were
16 calculated when we did our environmentally assisted
17 fatigue evaluations and whether or not if we modified
18 those calculations based on the questions if it would
19 impact the conclusion of the evaluation and the
20 selection of the sentinel locations of the locations
21 at which we will be monitoring GALL for environmentally
22 assisted fatigue during the period of extended
23 operation.
24 So, in response to the issue, we did redo
25 calculations for six locations to address the open

1 item. We submitted the results to the NRC in January
2 this year. There were no changes in any of the sentinel
3 locations due to this issue.
4 And, we are going to be managing the
5 effects of environmentally assisted fatigue by our
6 fatigue monitoring program during the period of
7 extended operation.
8 Next?
9 So, with that, I'm going to turn it over
10 to Randy Breymaier to talk about our aging management
11 programs.
12 MR. BREYMAIER: Good afternoon, I am Randy
13 Breymaier, Manager of Performance Engineering. I'll
14 be giving you a brief overview of the aging management
15 program and their implementation, performance
16 engineering owners license renewal and its
17 implementation at Fermi 2.
18 We have established a license renewal
19 program with an owner. This experienced program owner
20 has been an integral part of the license renewal core
21 team.
22 The license renewal program owner has been
23 a qualified and visual inspection and has been trained
24 in many areas of NDE.
25 The program owner has had EPRI training in

1 the area of aging management identification and the
2 owner has been actively involved in the scoping process
3 and the long-range planning of license renewal and has
4 a good working knowledge of this implementation plan.
5 All of the existing and new programs have
6 owners. These program owners were involved in the
7 establishment of the aging management scope within
8 their programs and they're involved in the long-range
9 planning effort of their AMPs.
10 They are responsible for tracking, program
11 enhancements and inspection schedules.
12 During the license renewal process,
13 commitments were made against exiting and new AMPs.
14 These commitments are contained within a USFAR
15 supplement.
16 MEMBER SKILLMAN: Randy, would you
17 explain, not specifically the staffing, but the
18 relationship between your license renewal AMP owners
19 and your existing plant staff.
20 I am assuming that there is some overlap
21 between these owners and your program engineers and
22 your system engineers.
23 MR. BREYMAIER: There is a large overlap
24 of the existing programs. The newer programs, we have
25 assigned to system engineers. Some of them have gone

1 to program engineers, some of them have gone to our site
2 engineering organization.
3 MEMBER SKILLMAN: So, when you say these
4 programs have owners, what you're trying to communicate
5 is that, for the BEO, you've got someone who is either
6 the accountable individual of the subject matter
7 expert, but, whose performance appraisal is affected
8 by his or her performance on that activity?
9 MR. BREYMAIER: That is correct. Every
10 one of these programs has an owner --
11 MEMBER SKILLMAN: Okay.
12 MR. BREYMAIER: -- and is responsible for
13 it.
14 MEMBER SKILLMAN: And, when you say
15 program, you're talking about 44 AMP owners?
16 MR. BREYMAIER: Yes, the AMPs, yes.
17 MEMBER SKILLMAN: Okay, thank you.
18 MR. BREYMAIER: Okay.
19 MEMBER POWERS: Well, presumably, these
20 people had other jobs that were permanent full-time
21 before this. And, Larry outlined for us, a heroic
22 amount of plant modification that's going on, that the
23 lives -- something's not getting done here.
24 MR. PETERSON: So, part of what Randy was
25 describing was our effort in terms of the license

1 renewal as was to ensure that the people owning the
2 programs going forward were fully engaged with the
3 development of the application as well as the
4 development of the programs.
5 As we look at the establish of the enhanced
6 aging management programs, in many cases, they aligned
7 with an enhancement existing programs. In other
8 cases, they were establishing programmatic
9 requirements that are, for example, our structures
10 monitoring program that were broader than what the
11 civil design engineers had previously.
12 As far as the plant modifications, we, as
13 most sites, we utilize AE firms to do the core design
14 functions for many of the capital modifications. And,
15 we've looked at that very closely in terms of the
16 overall impact on resources.
17 We've laid this out to ensure that we have
18 the right resources from a license renewal perspective
19 to maintain everything we need to do to be able to go
20 to the point of a period of extended operation and
21 beyond.
22 So, with all of this, I do not see any
23 specific resource challenges other than we will always
24 have resource challenges when new things come down the
25 pike and we just have to look at the proper blend between

1 internal resources and using SMEs for contract support.
2 MS. GOODMAN: We, additionally, will have
3 a project group for license renewal implementation that
4 will help the program owners with writing new
5 procedures and major procedure changes while evolving
6 them so that all that burden is not just added to the
7 existing personnel.
8 MR. POLSON: So, there's two things, we do
9 use contractors for specific modifications. And,
10 there are -- there is a lot going.
11 Also, we did look at resources and we did
12 obtain approval to hire approximately a hundred people
13 over our current head count.
14 So, we are looking at that and we will hire
15 as needed.
16 MEMBER POWERS: It just seems like it --
17 MR. POLSON: Yes --
18 MEMBER POWERS: -- it's a, I mean, license
19 renewal programs or add-ons, and sometimes, they're
20 just small additions to existing efforts and things
21 like that. But, sometimes, they're the brand new
22 efforts that require attention.
23 But, you laid out a fairly heroic set of
24 things going on. Plus, all the FLEX stuff going on and
25 a lot going on. You guys are going to give up sleeping.

1 MR. POLSON: There's a lot going on, but
2 we do have adequate resources to handle it.
3 MEMBER SUNSERI: How is the delivering the
4 nuclear promise playing into that workload, resource
5 management plan?
6 MR. POLSON: So, we're following, you
7 know, the guidance of nuclear promise. We have an
8 owner that's driving it. And, we have implemented, you
9 know, the recommendations that should be implemented
10 to this point which will help reduce the burden on
11 everybody.
12 MEMBER SUNSERI: Thank you.
13 MEMBER SKILLMAN: Please proceed.
14 MR. BREYMAIER: Next slide, John?
15 In reviewing the aging management programs
16 themselves, there were 45 AMPs, of which are two to be
17 developed such as the above-ground metal tanks as well
18 as the buried and underground piping programs.
19 The remaining 32 AMPs are existing, of
20 which, 22 will have enhancements made to them.
21 An example would be the containment
22 inspection program with enhancements to monitor
23 sand-cushioned drains for blockage and inspections to
24 assess whether corrosion is occurring to the primary
25 containment shell, one of which Boraflex monitoring was

1 deleted, leaving 44 AMPs.

2 Of the remaining 44 AMPs, 32 are consistent

3 with the GALL, 11 have exceptions to the GALL. An

4 example in this area would be the fire water system

5 program where ISG 2012-02 recommends yearly

6 inspections of sprinkler headers. But, it feasible to

7 only inspect many of them during refuel outages due to

8 dose considerations.

9 As a result, inspections will be performed

10 every 18 months instead of every 12.

11 An additional exception was added for

12 buried and underground piping program in April of 2016

13 due to ISG 2015-01. This exception is for two buried

14 stainless steel pipes between the condensate storage

15 tank and the turbine building which may not be coated.

16 And, there is one AMP that is

17 plant-specific and will be implemented by periodic

18 surveillance and preventative maintenance program.

19 This includes approximately 20 inspection activities

20 using visual or other NDE techniques at selected

21 locations to periodically monitor for material loss.

22 This AMP manages aging effects not covered

23 by other AMPs.

24 Next slide, John?

25 MEMBER REMPE: Before you leave that,

1 okay, so the Boraflex AMP was deleted because you're
2 going to replace and not use Boraflex anymore. But,
3 that hasn't been done yet, right? But, do you have a
4 time frame that just says before 2025?
5 MR. BREYMAIER: It will be done before
6 period of extended operation. We're in the process now
7 of seeing the right time frame budget-wise and
8 workload-wise to replace the racks.
9 MEMBER REMPE: Is it going to be in the
10 next, I don't know, ten years? Five years?
11 MR. BREYMAIER: It's got to be within the
12 next ten years.
13 MEMBER REMPE: Yes, yes, yes, that's true.
14 But, I mean, do you have any more specifics?
15 MR. BREYMAIER: I don't have firm date
16 right now, no.
17 MEMBER REMPE: Okay.
18 MEMBER SKILLMAN: Randy, I think Dr.
19 Rempe's asking you to explain that you have a commitment
20 as part of this application.
21 MR. BREYMAIER: That's why it was deleted.
22 The program was deleted. We have a commitment that we
23 --
24 MEMBER REMPE: License --
25 MR. BREYMAIER: -- that we will.

1 MEMBER REMPE: -- commitment to do it,
2 yes.
3 MR. BREYMAIER: Yes, we will have to do it,
4 yes.
5 MEMBER REMPE: Okay, thank you.
6 MS. GOODMAN: And, it will be a license
7 condition also.
8 MEMBER REMPE: Okay, thank you.
9 MR. BREYMAIER: In respect to the
10 implementation of license renewal, planning is in
11 progress to implement the required enhancements and new
12 programs. This plan includes lessons learned from
13 license renewal working groups and benchmarking of
14 utilities that have successfully implemented license
15 renewal.
16 It includes a long-range plan with three
17 services to ensure enhancements and new programs meet
18 their milestones. All program owners have attended
19 the required job familiarization training.
20 Program owners will receive vendor
21 training this year on aging management identification
22 and owners are tracking quarterly their enhancements
23 and inspection progress and reporting it to the license
24 renewal program owner.
25 Also, the OE process has been updated to

1 assure AMP owners review relevant OE.

2 In respect to the program and procedure

3 development, a long-range plan has been generated for

4 program and procedure development and enhancements.

5 The long-range plans supports time of planned

6 inspections.

7 AMPs requiring minor enhancements will be

8 completed by in-house personnel and new and those

9 requiring major enhancements will be completed with the

10 help of contract personnel. All new AMPs and

11 enhancements will be reviewed and approved by their

12 owners.

13 AMP inspections have started with

14 approximately 80 to be performed during the next refuel

15 outage. The majority of the remaining inspections are

16 being levelized and will be completed during the follow

17 four refuel outages, leaving additional refuel outage

18 to complete outstanding inspections.

19 Long-term plans for the station include

20 license renewal implementation activities plus

21 projects to support safe operation of the plant for an

22 additional 20 years.

23 Is there any other questions? If not,

24 I'll turn it back over to Keith for closing.

25 MR. POLSON: Okay, again, I wanted to

1 thank the Committee for their time. I just wanted to
2 put it in perspective.
3 License renewal is a big part of DTE's
4 future plans. We plan on reducing CO2 emissions by 80
5 percent based on the 2005 levels. So, Fermi 2 is a big
6 part of that.
7 And, also, I just want to make sure that
8 everyone knows that DTE is 100 percent committed to
9 continue to provide the resources that are necessary
10 to get the plant to a period of extended operation and
11 then through the period of extended operation.
12 So, again, thank you very much.
13 MEMBER SKILLMAN: Keith, thank you.
14 Colleagues, any questions for any of the
15 team from DTE?
16 If none, thank you, Keith, and DTE teams.
17 And, we are back to you, Ben, for your team
18 to come up and speak to us, please.
19 Please proceed.
20 MS. JAMES: Good afternoon, Chairman
21 Bley, Mr. Skillman and Members of the ACRS. My name
22 is Lois James and I am the License Renewal Project
23 Manager for Fermi 2 License Renewal Safety Review.
24 We are here today to discuss the review of
25 the Fermi 2 license renewal application as documented

1 in the final Safety Evaluation Report which was issued
2 in July 2016.
3 Joining me here at the table is Mr. Jeff
4 Mitchell, DLR Project Manager, who will be running the
5 slides.
6 Seated in the audience and joining by phone
7 are members of the technical staff who participated in
8 the review of the license renewal application and
9 conducted the onsite audits.
10 Next slide, please?
11 I will begin the presentation with a
12 general overview of the staff's review. I will then
13 discuss the closure of the open item related to the
14 effects of the reactor water environment on buried pipe
15 and the staff's conclusion.
16 Next slide?
17 DTE Electric Company, or DTE, or
18 Applicant, submitted a license renewal application for
19 Fermi 2 in April of 2014. The staff issued the safety
20 evaluation, or SER, with open items in January of 2016
21 and presented it to the ACRS Subcommittee on License
22 Renewal in March of 2016.
23 The staff closed the open item and issued
24 the final SER on July 12th.
25 Next slide, please?

1 The Applicant identified 45 aging
2 management programs, or AMPs, in the original LRA.
3 This slide identifies the Applicant's original
4 disposition of these AMPs in the left column and the
5 final disposition in the SER as a result of the staff's
6 review in the right column.
7 All of the AMPs were evaluated by the staff
8 for consistency with the GALL Report.
9 Since the Subcommittee meeting, there is
10 one new program that moved from consistent to
11 consistent with exception. That program is the buried
12 and underground piping program. This AMP was revised
13 as a result of the Interim Staff Guidance ISG 2015-01,
14 changes to the buried and underground piping and tank
15 recommendations.
16 Next slide, please?
17 Open Item 4.3.3-1 is related to the
18 Applicant's methodology used to determine the average
19 transient temperatures used to calculate the
20 environmentally assisted fatigue correction factors.
21 On December 15th, 2015, the staff held a
22 conference call with the Applicant to obtain
23 clarification on how the average transient
24 temperatures were calculated and to confirm that the
25 methodology used by the Applicant was consistent with

1 NUREG/CR-6909.

2 Based on this discussion, the staff
3 determined that the methodology used to calculate these
4 average transient temperatures were not consistent
5 with the guidance in NUREG/CR-6909.

6 The staff was concerned that this may
7 result in the underestimation of both the
8 environmentally assisted fatigue correction factors
9 and the resulting environmentally assisted fatigue
10 cumulative usage factor values for some locations.

11 By a letter dated January 14th, 2016, the
12 staff requested that the Applicant assess the impact
13 or revising the evaluations to use a method consistent
14 with NUREG/CR-6909 and that the Applicant submit a
15 description of the impact of this revision to the staff
16 for review.

17 By a letter dated January 22nd, the
18 Applicant provided a response. The staff and the
19 Applicant then followed up with two conference calls
20 to discuss and clarify the Applicant's response.

21 By a letter dated March 10th, the Applicant
22 supplemented its response to further clarify fatigue
23 monitoring program description.

24 Based on its review, the staff finds the
25 Applicant's response acceptable because the Applicant

1 identified all of the locations that used an average
2 temperature to calculate the environmentally assisted
3 fatigue cumulative usage factors and reevaluated them
4 to either (a) use the design temperature or maximum
5 operating temperature instead of an average
6 temperature; or, (b) use an average temperature
7 determined in a manner consistent with NUREG/CR-6909.
8 Next slide?
9 In conclusion, the staff has determined
10 that the requirements of 10 CFR 54.29(a) have been met
11 for the license renewal of Fermi 2.
12 This concludes the staff's presentation.
13 We are available for questions from the Committee.
14 MEMBER SKILLMAN: Lois, thank you.
15 Members, questions for the NRC staff,
16 please?
17 Hearing none, Lois and Jeff, thank you. I
18 thank you, Ben.
19 And, with that, Dennis, I turn it back to
20 you.
21 Oh, comments, I'm sorry. Making sure the
22 phone line is open. While we're waiting, is there
23 anybody in the audience that would have a comment?
24 Those on the phone line, if you are --
25 PARTICIPANT: Fermi 2 Plant Support Team.

1 MEMBER SKILLMAN: Well, good afternoon.
2 Anybody else out there on the phone line,
3 please? Is there anybody on the phone line that would
4 prefer or wish to make a comment, please?
5 Hearing none, let's close the phone line.
6 And, Dennis, we're back to you.
7 Thank you.
8 CHAIRMAN BLEY: Thank you, Dick. That
9 was pretty quick. But, this was a pretty clean
10 application, I think, from what we heard at the
11 Subcommittee.
12 At this time, we will shortly recess.
13 We'll come back at 2:30. I want to read through all
14 three letters today.
15 I'm going to start with Charlie's and then
16 ask for Harold's and then Dick's. Charlie, I'm going
17 to say we'll come back to your letter tomorrow.
18 At this point, yes, just a moment.
19 We're going off the record at this point.
20 No more for today.
21 (Whereupon, the above-entitled matter
22 went off the record at 2:02 p.m.)
23
24
25

Turkey Point Nuclear Power Plant

Units 6 & 7

Combined License Application

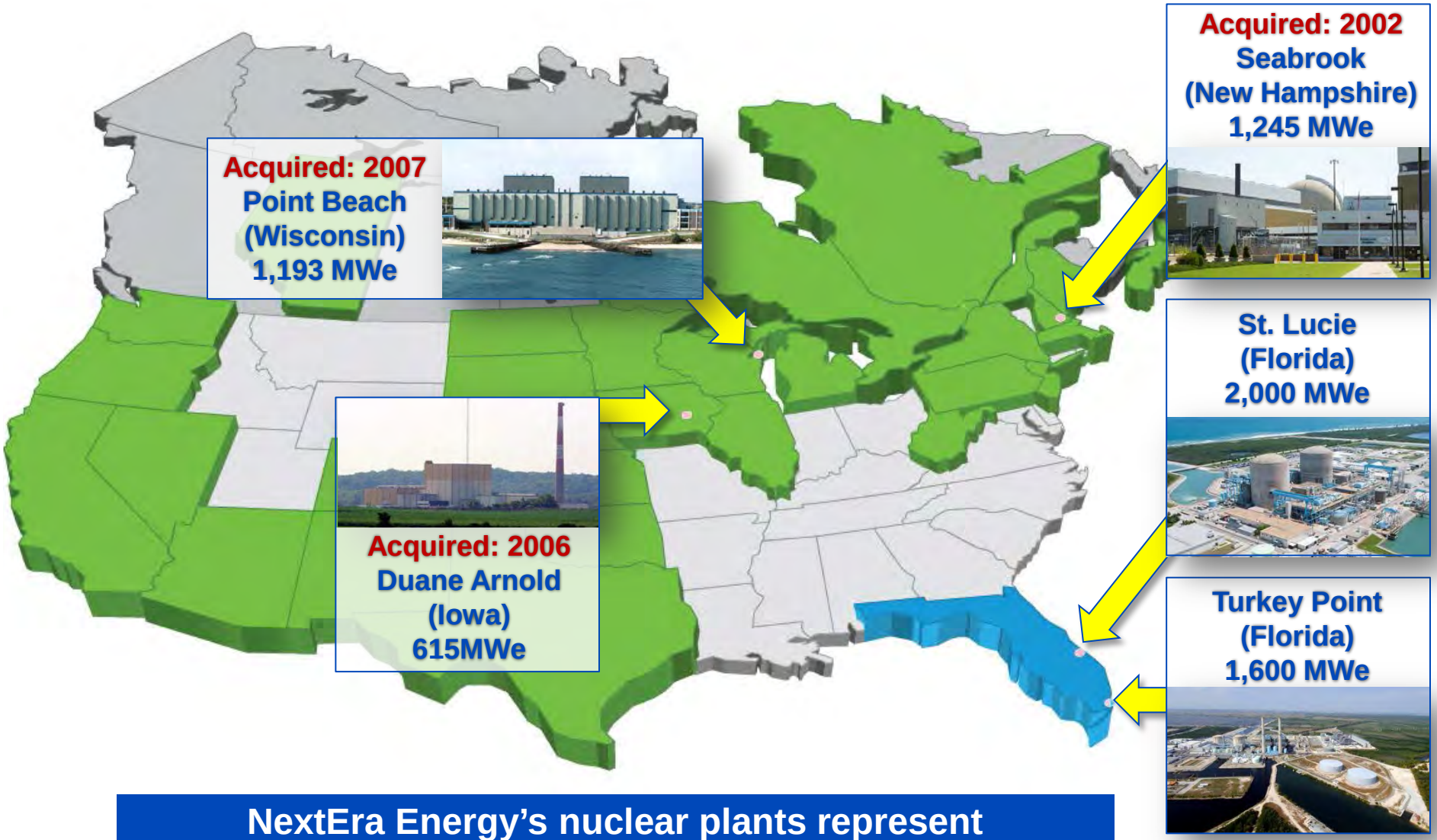
September 8, 2016

Turkey Point Nuclear Plant Units 6 & 7

Introduction

William Maher
Senior Licensing Director
New Nuclear Projects

NextEra Energy's nuclear fleet is 4th largest in MW capacity and number of reactors in the United States



NextEra Energy's nuclear plants represent approximately 24 percent of the company's generation

Turkey Point Nuclear Plant Units 6 & 7

- Introduction
- Chap. 1 General Description of the Plant
- Section 2.1 Geography and Demography
- Section 2.4 Hydrologic Engineering
- Section 11.2 Liquid Waste Management System
- Section 13.3 Emergency Planning
- Chap. 19 Probabilistic Risk Assessment

Turkey Point Nuclear Plant Units 6 & 7

- Introduction
- **Chap. 1 General Description of the Plant**
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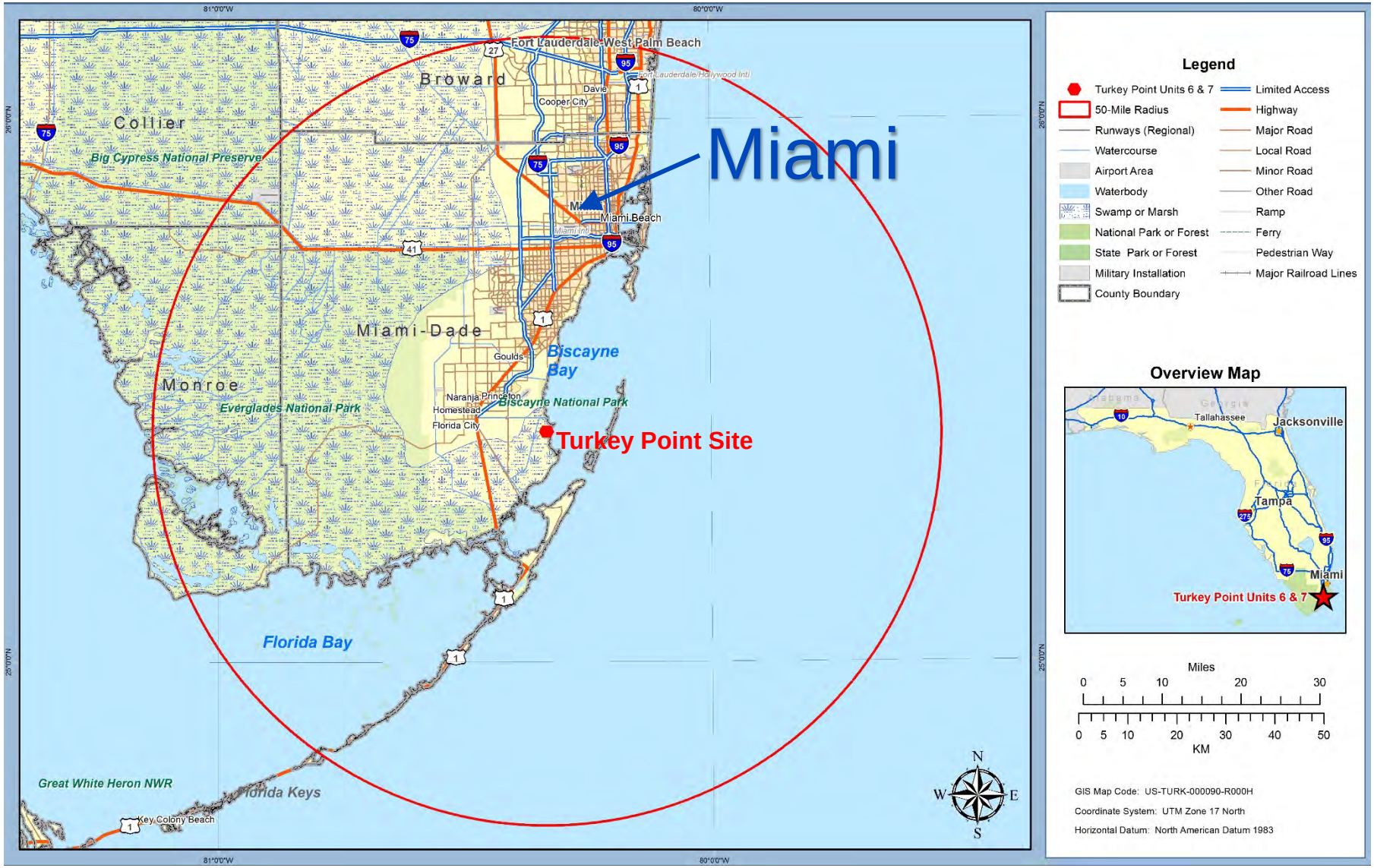
Turkey Point Nuclear Plant Units 6 & 7



Source: FSAR Figure 2.1-201

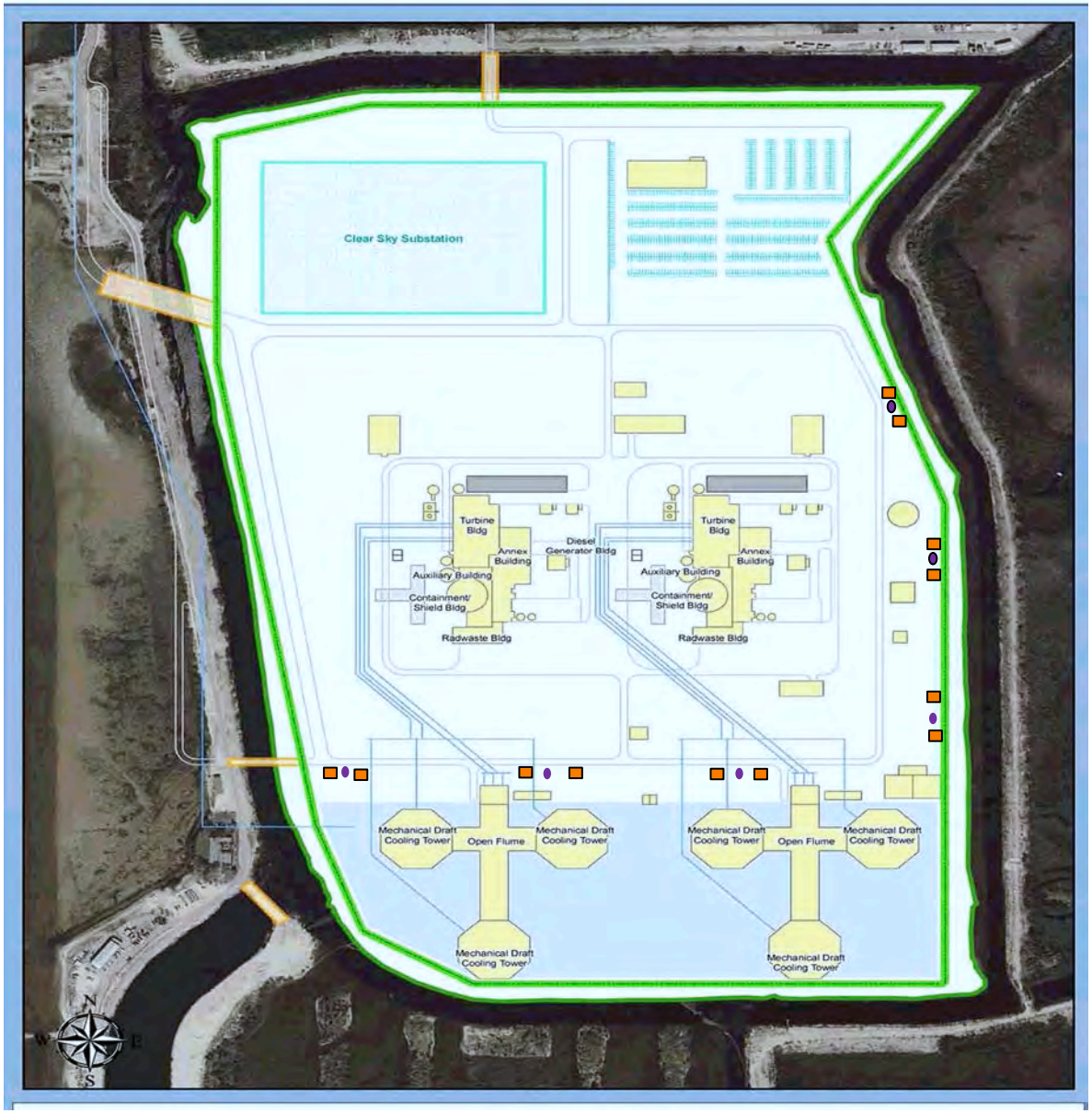
Turkey Point Nuclear Plant Units 6 & 7

Turkey Point Site Area

Source: FSAR Figure 2.2-201

Turkey Point Nuclear Plant Units 6 & 7

Site Plot Plan



Turkey Point COLA Changes Since R-COL

- **Fukushima event**
- **Central & Eastern US Seismic Source Characterization sensitivity assessments**
- **Electrical Bulletin 2012-01 response**
- **AP1000 Generic Design Changes (reviewed on Levy docket)**
  - Condensate Return & Passive RHR Cooling
  - Main Control Room Operator Dose
  - Main Control Room Heat Load
  - Hydrogen Venting in Containment
  - Plant Monitoring System (PMS) Flux Doubling to comply with IEEE 603

Focus Areas for Discussion

- Section 2.1 Geography and Demography – Population density
- Section 2.4 Hydrologic Engineering – Sea Level Rise
- Section 11.2 Liquid Waste Management System – Deep Well Injection System (DIS) modeling & release monitoring
- Section 13.3 Emergency Planning – TSC instrumentation power
- Chap. 19 Probabilistic Risk Assessment – Aviation accidents core Damage Frequency (CDF)

Turkey Point Nuclear Plant Units 6 & 7

- Introduction
- Chap. 1 General Description of the Plant
- **Section 2.1 Geography and Demography**
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Section 2.1 Population Considerations

- **Population considerations under 10 CFR 100.21 requirements**
  - Exclusion Area (EA) controls and Low Population Zone (LPZ) designation [§100.21(a)]
  - Distance to nearest densely populated center [§100.21(b)]
  - Population density [§100.21(h)]
- **Turkey Point meets EA, LPZ, and densely populated center 10 CFR 100.21 requirements**
- **Regulatory Guide 4.7, Revision 2, guidance used to determine if Turkey Point is in an area of "low density"**
  - Turkey Point meets area of "low density" guidance between one and five miles.
  - Turkey Point exceeds 500 persons per square mile (ppsm) between five and 20 miles
- **The population density exceedances are not considered "well in excess of" the 500 ppsm guidance criterion.**
  - Regarding §100.21(g) and §100.21(h) that physical site characteristics not pose a significant impediment to the development of emergency plans, FPL demonstrated acceptable measures for public radiological safety when assessing accidents at the Turkey Point site.

Section 2.1 Population Considerations

- **In accordance with RG 4.7 site safety considerations and § 100.21(h) requirements, the principal factors influencing FPL's selection of the Turkey Point site over other alternative sites with lower nearby population densities include several unique safety, economic, reliability and environmental attribute advantages that would not be realized if the plant was developed elsewhere.**
  - Ability to balance generation and load in southeast Florida
  - Unique cooling water supply source
  - Land availability
  - Existing nuclear power plant infrastructure
  - Emergency planning infrastructure
- **50-mile population dose risk impact from Unit 6 or 7 severe accidents (2.7×10^{-1} person-rem/Ryr) was established as supporting a SMALL impact determination in the DEIS.**

10 CFR 100 analysis concluded no alternative site was environmentally preferable.

Turkey Point Nuclear Plant Units 6 & 7

- Introduction
- Chap. 1 General Description of the Plant
- Section 2.1 Geography and Demography
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Antecedent Water Level

- **Regulatory Basis**
  - 10 CFR 50, Appendix A, General Design Criteria (GDC) 2, Design bases for protection against natural phenomena – requires appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area
  - RG 1.59, Appendix C, Simplified Methods of Estimating Probable Maximum Surges – uses antecedent water level comprising 10% exceedance high spring tide and initial rise (or sea-level anomaly) to meet GDC 2
  - RG 1.206, Part I, Subsection C.I.2.4.5.2, Surge and Seiche Water Levels – states that COL applications include 10% exceedance high spring tide and initial rise (or sea-level anomaly) as the antecedent water level

- **PTN 6 & 7 FSAR additionally added a projected (linear trend analysis based on actual measurements) long-term sea level rise for the antecedent water level**

Antecedent Water Level

- **Long-term Sea Level Rise (1.0 foot for design plant life of 60 years)**
  - Analyzed based on historical data from nearby tide gages with long data records
    - -- Miami Beach (1931-1981)
    - -- Key West (1913-2010), missing data from 1936 to 1940 and 1953
  - Linear and non-linear trend analyses performed

	100-year Sea Level Trend	
Data Set	**Linear Extrapolation**	**Nonlinear (2nd order) Extrapolation**
Key West (1941-2010)	0.69 ft	1.54 ft
	R^2 = 0.45 *	R^2 = 0.46
Key West (1931-1981)	0.66 ft	-0.97 ft ***
	R^2 = 0.28	R^2 = 0.29
Miami Beach (1931-1981)	0.78 ft **	-2.79 ft ***
	R^2 = 0.32	R^2 = 0.35
Miami Beach (1931-2010) Missing data estimated from Key West using linear regression imputation	0.77 ft	0.50 ft
	R^2 = 0.53	R^2 = 0.53

* R^2 is the coefficient of determination
** Same as NOAA's analysis in FSAR Subsection 2.4.5, Reference 206
***The decline in sea-level is not considered to be a plausible outcome and therefore second order extrapolation is not appropriate for the sea-level data from 1931 to 1981.

FPL Response to RAI 02.04.05-5, Table 1

Turkey Point Nuclear Plant Units 6 & 7

- Introduction
- Chap. 1 General Description of the Plant
- Section 2.1 Geography and Demography
- Section 2.4 Hydrologic Engineering
- **Section 11.2 Liquid Waste Management System**
- Section 13.3 Emergency Planning
- Chap. 19 Probabilistic Risk Assessment

Section 11.2 – Liquid Waste Management System

Discharge of Blowdown Water Site Dependent

- **Cooling water study performed to select discharge alternative**
  - Scope of study included analyzing alternatives for discharging blowdown from circulating water system (CWS)
  - Nine potential alternatives were identified within reasonable proximity
    - -- Biscayne Bay
    - -- Card Sound
    - -- Atlantic Ocean
    - -- Card Sound Canal
    - -- Turning Basin
    - -- Lower Floridan Aquifer (Boulder Zone)
    - -- Wastewater Treatment Plant
    - -- Existing Cooling Canal System
    - -- Wetlands Rehydration
  - The potential alternatives went through a screening process which considered:
    - -- Statutory or legal restriction prohibiting discharge
    - -- Capacity of water body/treatment system to treat or accommodate discharge
    - -- Technical feasibility of construction/operation of discharge alternative
  - Only one alternative determined to be feasible, deep well injection of blowdown discharge to the Boulder Zone

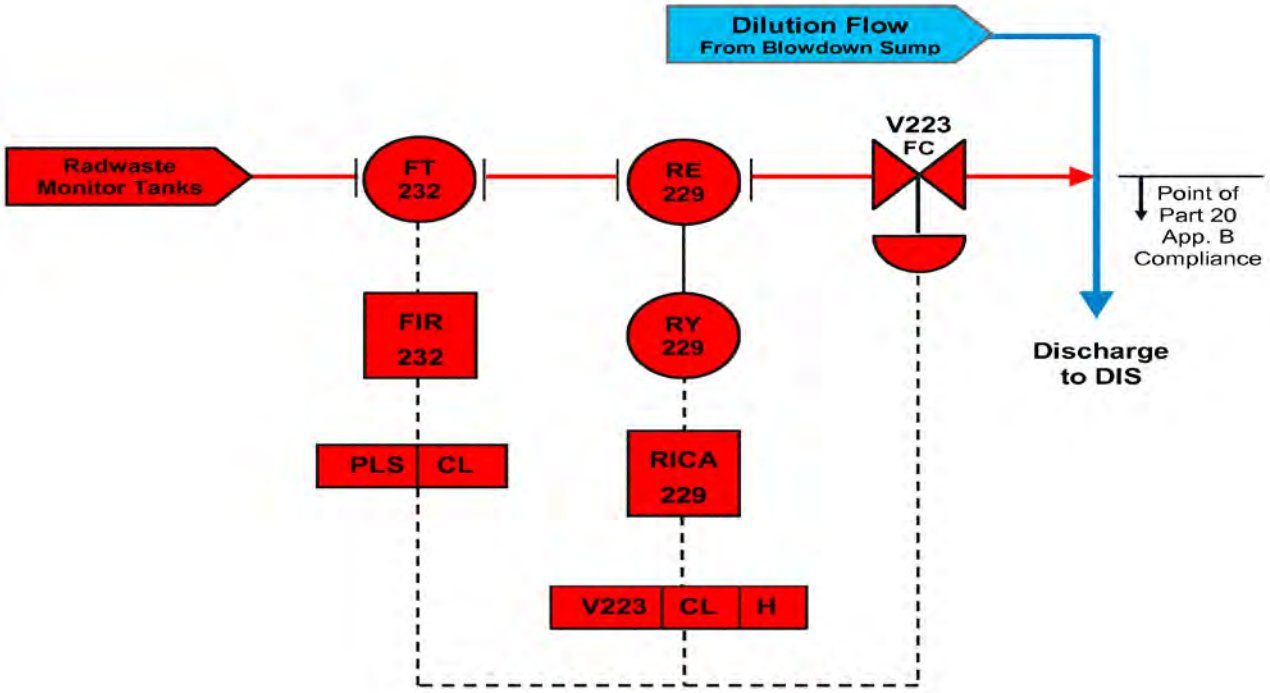
Liquid Waste Management System

Collection of liquid waste and liquid radioactive waste:

- **Liquid waste, wastewater from main condenser cooling system (blowdown), retention basin, and sanitary waste treatment system collected in blowdown sump**
- **Processed liquid radioactive waste discharged to plant blowdown sump discharge line prior to release (injection)**
  - Required minimum dilution factor to control concentrations of liquid radioactive waste discharges to 10 CFR Part 20, Appendix B, effluent concentration limits met by specifying flow rates at blowdown sump discharge and liquid radwaste discharge lines
    - -- The required minimum dilution factor is calculated and applied prior to release of liquid radioactive waste
    - -- 6000 gpm typical dilution flow per unit (DCD Table 11.2-8)
  - Implementation of the liquid radioactive waste effluent control program will be in accordance with Units 6 & 7 Offsite Dose Calculation Manual

Turkey Point Nuclear Plant Units 6 & 7

Liquid Waste Management System Design



Liquid Waste Management System Design

Liquid Radwaste Piping Integrity/Monitoring

- **Liquid radwaste piping:**
  - The liquid radwaste system discharge pipeline (i.e., red portion) connects to the blowdown sump discharge piping downstream of the blowdown sump
    - -- Guard-pipe enclosed (Secondary Containment)
    - -- Leakage monitoring of pipe and underground pit where pipe ties into blowdown sump discharge implemented as part of Radiation Protection Program
  - The injectate piping (i.e., blue line) is from the blowdown sump discharge connection point to deep injection wells
    - -- Single-walled, partially buried, constructed of steel
    - -- Piping, manifolds, valves, controls, and appurtenances designed to minimize inadvertent releases
    - -- Leakage monitoring consists of periodic visual inspection (accessible portions) as part of routine operation and maintenance activities or remote surveillance as part of Groundwater Monitoring Program

Liquid Waste Management System Design

- **What controls are available to detect and terminate the release of a liquid radwaste discharge if it does not meet the calculated dilution criteria?**

Refer to Slide 19

– Effluent Discharge Flow (FIR232) instrument monitors discharge flow from the liquid radwaste system (WLS) to the environment and maintains a record of total discharge flow for radiological assessments of offsite releases. The channel is used as an input into the WLS discharge dilution ratio. The plant control system (PLS) performs the flow ratio and provides the input into V223. A Low-1 dilution ratio causes an alarm and a Low-2 dilution ratio causes the automatic closure of V233.

– High Radiation (RE229) closes V223 and alarms and stops Monitor Tank pumps.

Section 11.2 – Liquid Waste Management System

Lower Floridan Aquifer (Boulder Zone) Alternative for CWS Blowdown Discharge:

- **Consists of blowdown discharge via deep well injection system (DIS) to the Lower Floridan aquifer (Boulder Zone), approximately 3000 feet below ground surface (bgs)**

Boulder Zone - highly permeable zone containing saltwater:

- **Permitted by Florida Department of Environmental Protection for injection of sewage, industrial, and domestic wastes in South Florida**
  - Used in Florida for underground disposal of liquid waste since 1943
  - 180 active Class I injection wells permitted
    - -- Class I injection wells- industrial and municipal disposal wells which inject fluids beneath the lowermost unit containing an underground source of drinking water (USDW)
      - Most municipal Class I wells dispose of treated municipal effluent
      - Power plant industrial Class I wells primarily dispose of cooling tower blowdown

Section 11.2 – Liquid Waste Management System

- **What parameters/assumptions were used in the confinement modeling for the injection well?**
  - The confinement model was based on the assumption that the hydraulic parameters for the confining strata throughout the model domain were similar to the values obtained from Turkey Point exploratory well EW-1 and other injection wells in South Miami-Dade County (Florida Key Aqueduct Authority and South District WWTP systems). A sensitivity analysis was performed to evaluate the potential impacts of “leakier” conditions.

Turkey Point Nuclear Plant Units 6 & 7

- Introduction
- Chap. 1 General Description of the Plant
- Section 2.1 Geography and Demography
- Section 2.4 Hydrologic Engineering
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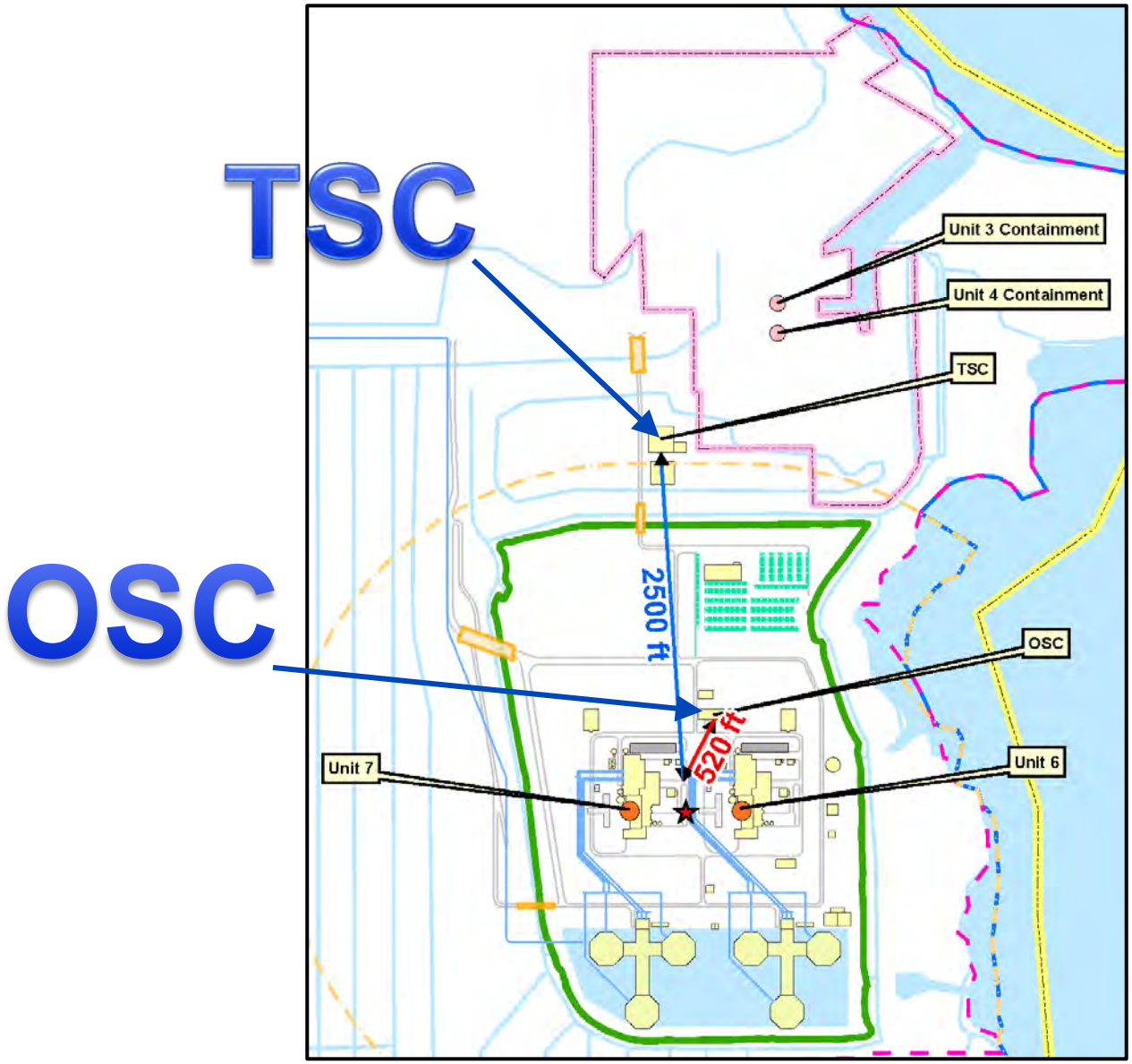
Turkey Point Nuclear Plant Units 6 & 7

Emergency Plan Facilities



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- Introduction
- Chap. 1 General Description of the Plant
- Section 2.1 Geography and Demography
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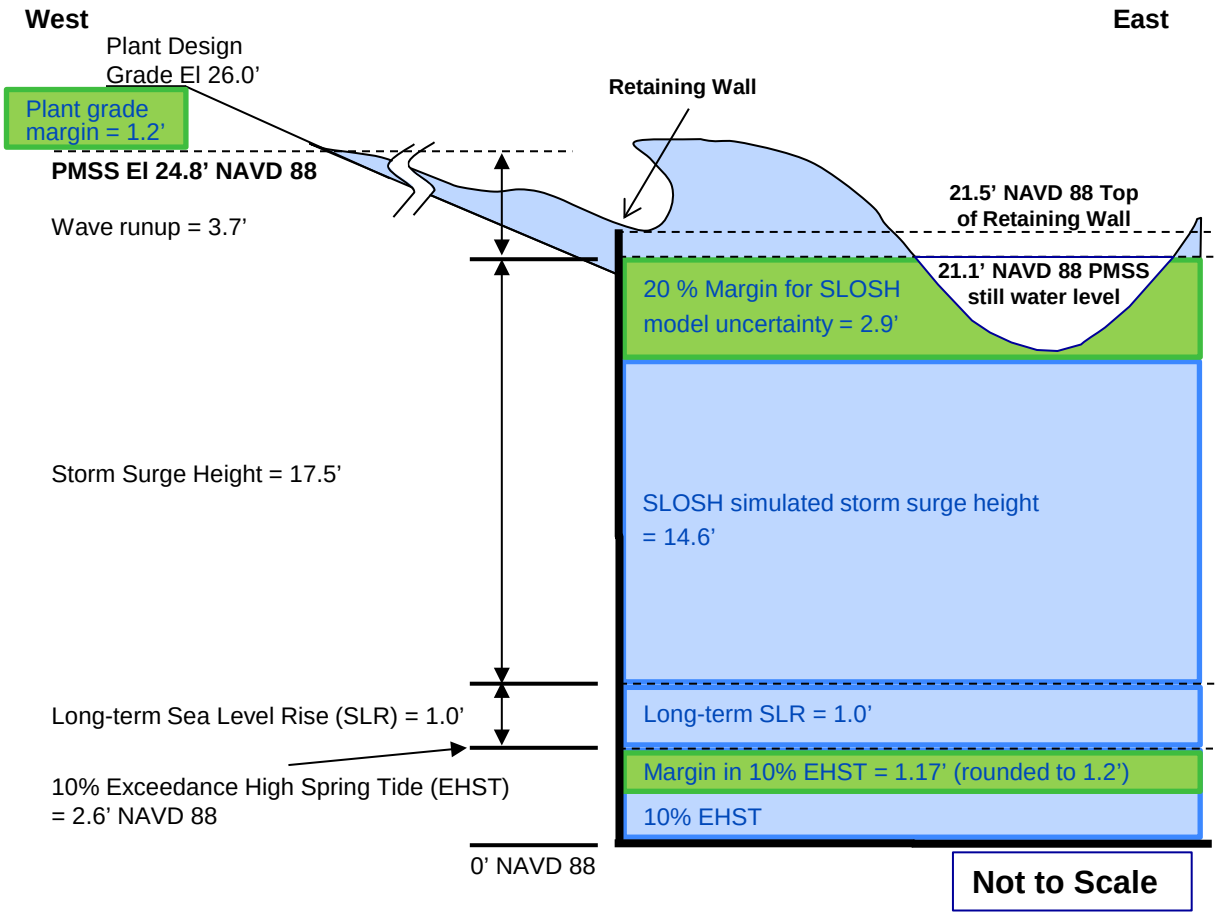
Section 19.58 – Winds, Floods, and Other External Events

- **Two Screening Criteria used to determine whether a detailed PRA is required**
  - External event category screened out on the basis of its annual frequency (less than 1.0E-7/yr)
  - External event category screened out based on the annual core damage frequency (CDF) associated with that external event category—If CDF does not exceed 1.0E-8/yr, the external event category can be screened out
- **Annual frequency of aviation accidents presented in Section 2.2 exceeds the first Criteria**
  - CDF is calculated using conservative assumptions regarding availability of offsite power and availability of standby non-safety systems
  - Conditional Core Damage Probability (CCDP) of 5.85E-8 is based on high winds scenario since similar damage would occur
  - The base case result (2.26E-13 events/year) is below the screening criterion of 1.0E-8/year

The DCD CDF criteria of 1.0E-08 is satisfied and a detailed PRA is not required.

Turkey Point Nuclear Plant Units 6 & 7

Margin in Plant Design Grade Estimate



Approximate Total Margin = (1.2 + 2.9 + 1.2) ft **= 5.3 ft**

QUESTIONS?

U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

Presentation to the ACRS Full Committee

Turkey Point
Units 6 and 7 COL Application Review

Overview of Advanced Safety Evaluation (ASE)

September 8, 2016

ACRS Full Committee Presentation Outline

ASE Section	Subject	Technical Staff
2.2	Aircraft Hazards	Rao Tammara
13.3	TSC Location TSC Power Supplies Population (“Initial”) Siting Criteria)	Bruce Musico

Overview

- Staff's philosophy for presentations
  - The staff does not intend to brief the ACRS committee on Certified Design or standard content material

- The staff intends to provide a high-level description of the site-specific content. The staff does not intend to brief every site-specific item, rather it intends to brief the ACRS based on feedback from the ACRS Subcommittee meeting.

Turkey Point COL Application

- Turkey Point Application consists of:
  - Material incorporated by reference (IBR) from the AP1000 Design Control Document (DCD), Revision 19
  - Standard content material (applicable to all AP1000 COL applicant)
  - Turkey Point plant specific information

U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

Staff Presentation to ACRS Full Committee

Turkey Point
Units 6 and 7 COL Application

ASE Chapter 2, Site Characteristics
Section 2.2 – Nearby Industrial, Transportation, and Military Facilities
(Aircraft Hazards)

Rao Tammara

September 8, 2016

2.2 Nearby Industrial, Transportation, and Military Facilities

Key Review Areas

Evaluation of Potential Accidents

Aircraft Crash Probability

- The applicant calculated aircraft crash probability of 3.86×10^{-6} per year based on considering airport operations (takeoff and landing) and non-airport operations, using DOE standard methodology and aircraft crash frequencies for general aviation, commercial aviation, military large and small aircrafts. This determined aircraft crash probability exceeds the criterion of 1×10^{-7} per year. However, considering the design basis conditional core damage probability of 5.85×10^{-8} for AP1000 design, the core damage frequency (CDF) associated with that aircraft crash probability is determined to be lower than 1×10^{-8} per year, and poses no undue risk to the health and safety of public. This is further addressed in SER Chapter 19.

2.2 Nearby Industrial, Transportation, and Military Facilities

Key Review Areas

Evaluation of Potential Accidents

Aircraft Crash Probability

- The staff reviewed the total aircraft crash probability of 3.86×10^{-6} per year (2.55×10^{-7} per year from airport operations and 3.61×10^{-6} per year from non-airport operations) which exceeds the criterion. It can be observed that the aircraft crash probability is primarily due to non-airport operations.

Staff performed an independent confirmatory analysis using conservative total flight data obtained from the Federal Aviation Administration (FAA), within 5 miles of the plant site, to determine aircraft crash probability of 5.26×10^{-7} per year using air carrier accident rate of 3.0×10^{-9} per aircraft-mile, and 3.2×10^{-6} per year using all military aircraft crash rate of 1.86×10^{-8} crashes per mile. The staff's determined aircraft crash probability is lower, however, comparable with applicant's determined aircraft crash probability.

2.2 Nearby Industrial, Transportation, and Military Facilities

Key Review Areas

Evaluation of Potential Accidents

Staff reviewed the applicant addressed site specific evaluations of Potential Accidents. Based on the review of the applicant provided information, responses to the RAIs, staff evaluations and staff's independent confirmatory analyses, the staff found the applicant's conclusions to be acceptable as the evaluations are in accordance with the guidance provided in NUREG-0800 Section 2.2.3, and meet regulatory requirements of 10 CFR 100.20(b).

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Staff Presentation to ACRS Full Committee

Turkey Point
Units 6 and 7 COL Application

ASE Chapter 13, Conduct of Operations
Section 13.3 – Emergency Planning

Bruce Musico

September 8, 2016

13.3 Emergency Planning
Technical Support Center (TSC)

- TSC Location (NUREG-0696, 1981)
  - Basis for 2-min walking time to Control Room:
    - Provide necessary (face-to-face) management interaction and technical information exchange
    - Provide TSC access to Control Room information not available in the TSC data system
      - During recent events at nuclear power plants, telephone communications were ineffective in providing all of the necessary management interaction and technical information
      - This demonstrated the need for face-to-face communications

Prior TSC Location Reviews

- 3/12/07 – Clinton Power Station, ML070540270
- 12/3/08 – Vogtle ESP ACRS transcript (Tr. at 156-189)
- 1/16/09 – Vogtle ESP ASLB Question 24, ML090160502
- 3/25/09 – Vogtle ESP staff testimony, ASLB transcript, p. M-2175, ML090910741
- Sept. 2012 – Vogtle COL, FSER (NUREG-2124), Section 13.3 (Emergency Planning), ML12271A048

Turkey Point Site
Common TSC Location

- Turkey Point Nuclear Training Building
  - Outside Protected Area (PA), between Units 3/4 & 6/7 Control Rooms
  - TSC to Control Rooms – approx. 2600 ft (10-15 minute walk)
  - Procedures facilitate passage from outside PA into Control Rooms
- Communications Technologies
  - Updated computer equipment, teleconferencing, real time system monitoring through plant computer networks, and telephone and radio systems for primary and emergency communications
- Technical Information Exchange
  - Access to plant drawings, procedures, and computer applications needed to support the plant evaluation and decision-making processes of the Emergency Response Organization

TSC Power Supplies

- TSC Power Supplies (NUREG-0696)
  - Data equipment and power supplies need not meet safety-grade or Class 1E requirements
  - Power supply failures shall not cause a loss of stored data vital to TSC functions
  - Sufficient alternate or back-up power source shall be provided
- Turkey Point Common TSC
  - A reliable and backup electrical power supply is available
  - EP ITAAC 5.1.6 will verify

Evacuation Time Estimate (ETE)

- 10 CFR 50.47(b)(10), Part 50 App. E.IV.2-.7
- Regulatory Guide 4.7 (General Site Suitability)
  - *Population Considerations* – A reactor should preferably be located such that, at the time of initial site approval and within about 5 years thereafter, the population density does not exceed 500 persons per square mile out to 20 miles.
  - *Emergency Planning* – An ETE assesses the feasibility of taking protective measures for the population in the surrounding area.

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Diablo Canyon Process Protection System License Amendment Request Informational Briefing

ACRS Committee Meeting

Presented by: NRR / EICB

John Lubinski	Director DE
Mike Waters	Branch Chief EICB
Balwant Singal	Project Manager DORL
Rich Stattel	Technical Reviewer EICB

Thursday September 8, 2016

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Presentation Outline / Agenda

- Introduction, Project Overview
- Safety Evaluation Topics
  - Communication Independence
  - Diversity and Defense in Depth (D3)
  - Control of Access / Secure Development and Operational Environment
  - System Time Response / Deterministic Performance
- ACRS I&C Subcommittee Discussion Summary
- Lessons Learned on the Digital I&C Licensing Process (ISG-06)

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Licensing Activities

- License Amendment Request (LAR) submittal received on October 26, 2011.
- First of a kind design change with Diablo as Lead Plant.
- Application accepted by the NRC staff on Jan 13, 2012.
- The review has been conducted by Instrument and Controls Branch (EICB), PRA Licensing Branch (APLA), PRA Operations and Human Factors Branch (APHB), Reactor Systems Branch (SRXB), and Technical Specification Branch (STSB) with EICB as the lead and key branch. APLA, SRXB, and STSB do not have safety evaluation input but will concur on the final LAR package.

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Licensing Activities

- The NRC staff conducted 32 public meetings from May 2012 to July 2015 to discuss various aspects of the LAR.
- The NRC staff conducted 4 Regulatory Audits between November 2012 and June 2015.
- The NRC staff issued four rounds of RAIs between August 2012 and December 2015.
- The licensee made 25 submittals from October 2011 to now to provide supplemental information in support of the NRC staff requests.
- There were two ACRS sub-committee meetings (February 2014 and April 2016) and one ACRS full-committee meeting in March 2014.

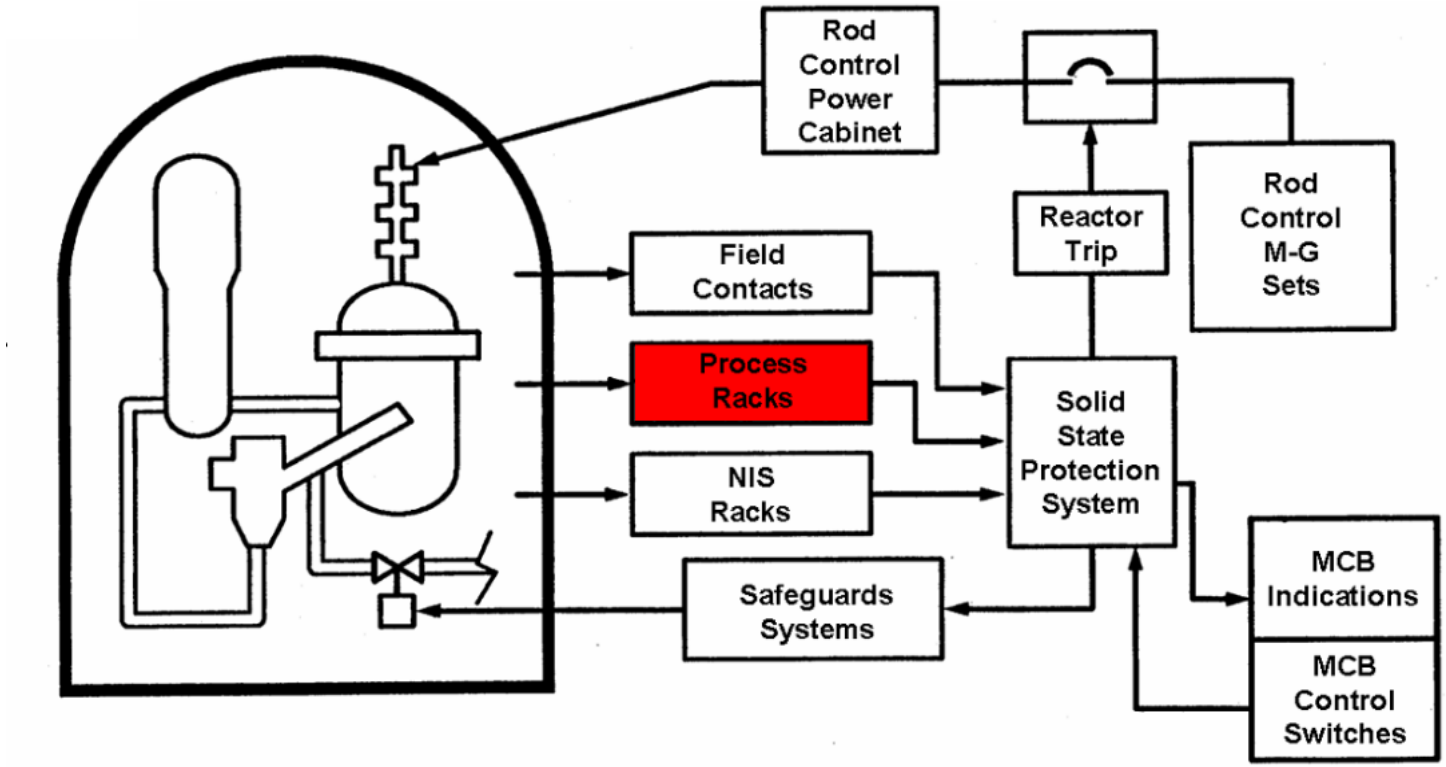
License Amendment Request Status

Draft LAR Package is ready and is presently going through final review by EICB and Division of Operating Reactor Licensing (DORL).

Concurrence with the review branches (EICB, SRXB, STSB, APHB, and APLA) will be conducted after considering recommendations of the ACRS Full Committee meeting being held today.

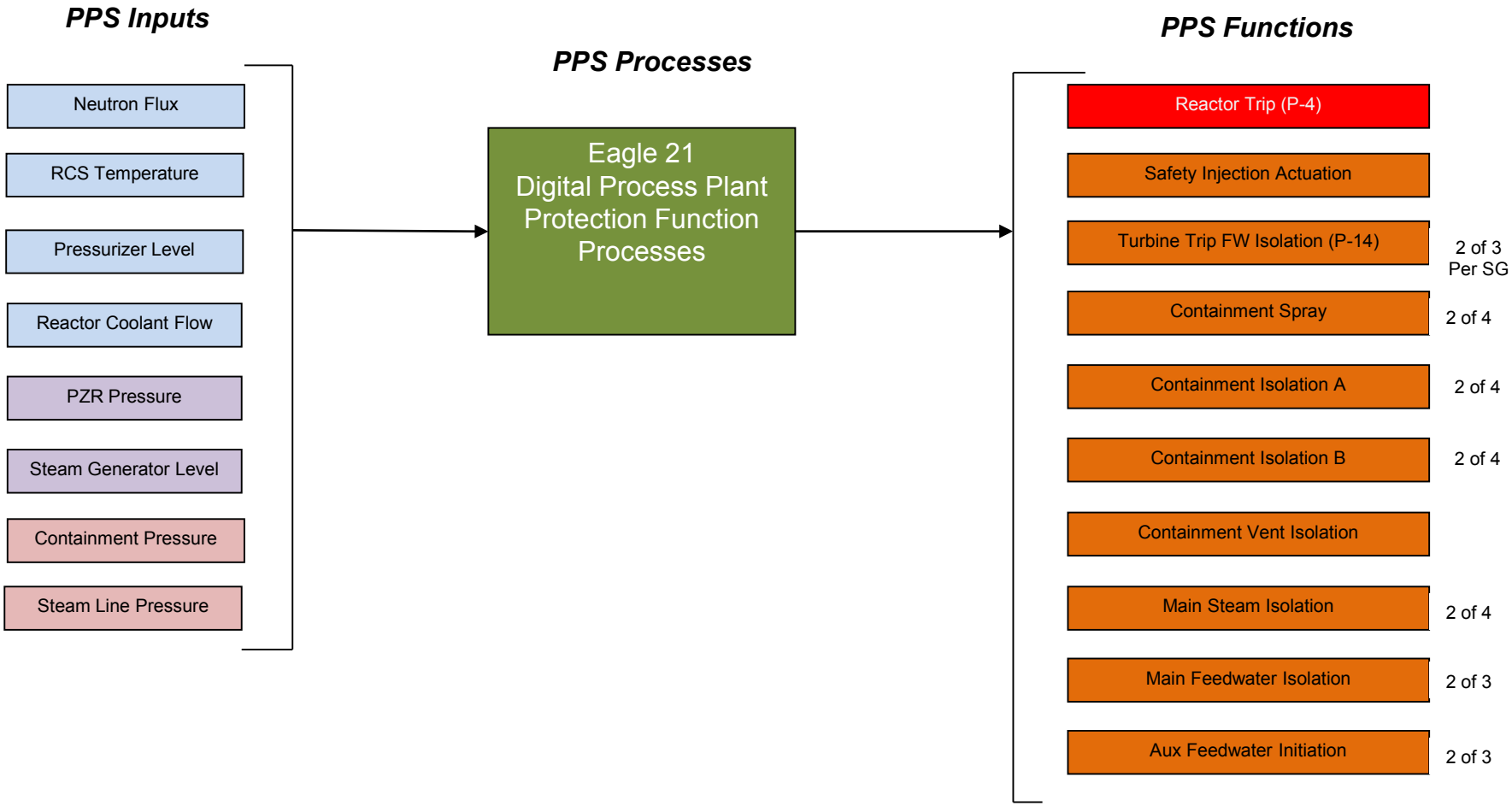
PPS Replacement Design

- Project Scope



Overview of Diablo Canyon Application

Current PPS System Functions



Overview of Diablo Canyon Application

New PPS System Functions

PPS Inputs

- Neutron Flux
- RCS Temperature
- Pressurizer Level
- Reactor Coolant Flow
- PZR Pressure
- Steam Generator Level
- Containment Pressure
- Steam Line Pressure

PPS Processes

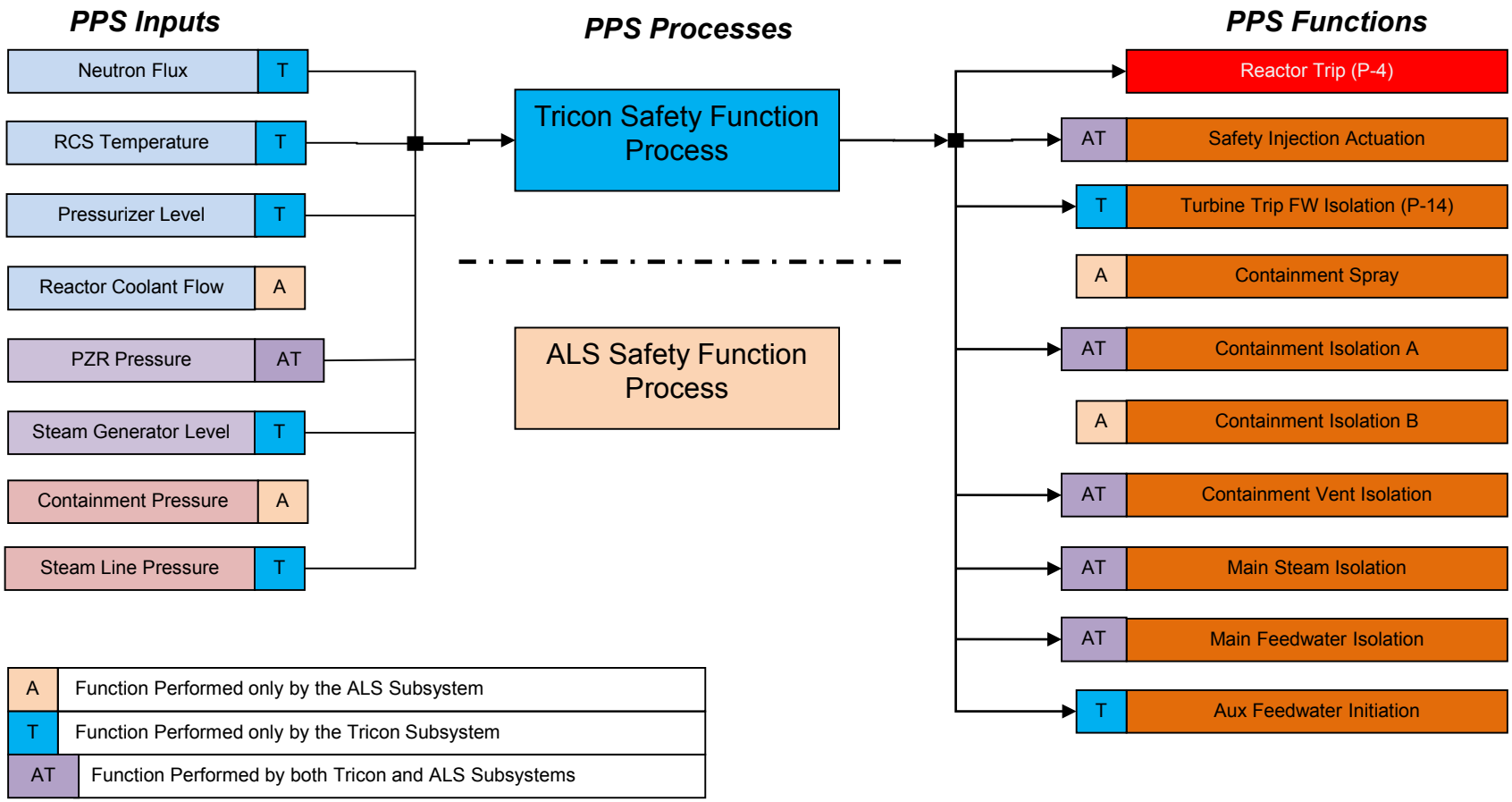
- Tricon Safety Function Process
- ALS Safety Function Process

PPS Functions

Reactor Trip (P-4)	
Safety Injection Actuation	
Turbine Trip FW Isolation (P-14)	2 of 3 Per SG
Containment Spray	2 of 4
Containment Isolation A	2 of 4
Containment Isolation B	2 of 4
Containment Vent Isolation	
Main Steam Isolation	2 of 4
Main Feedwater Isolation	2 of 3
Aux Feedwater Initiation	2 of 3

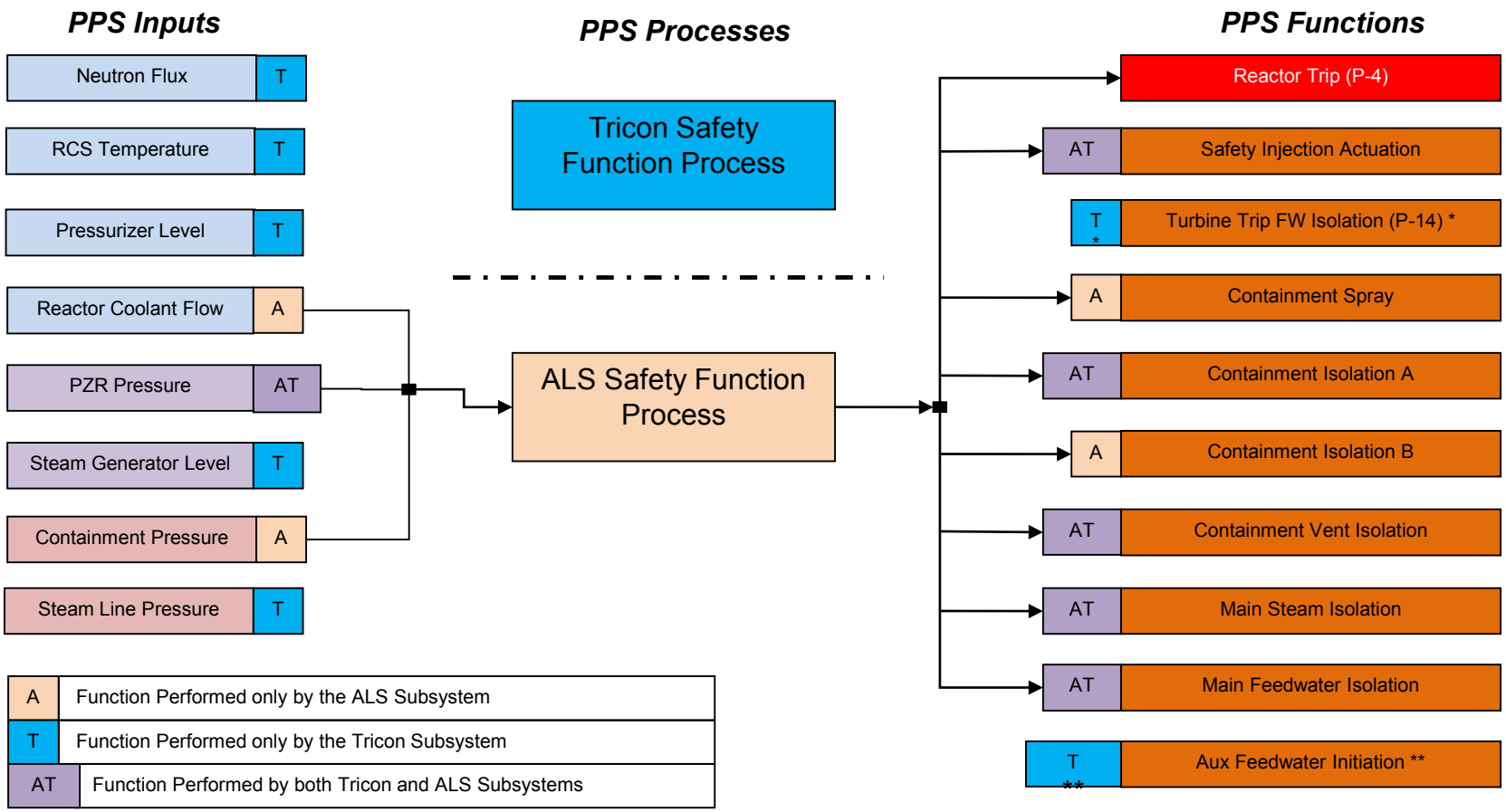
Overview of Diablo Canyon Application

PPS System Tricon Function Allocation



Overview of Diablo Canyon Application

PPS System ALS Function Allocation

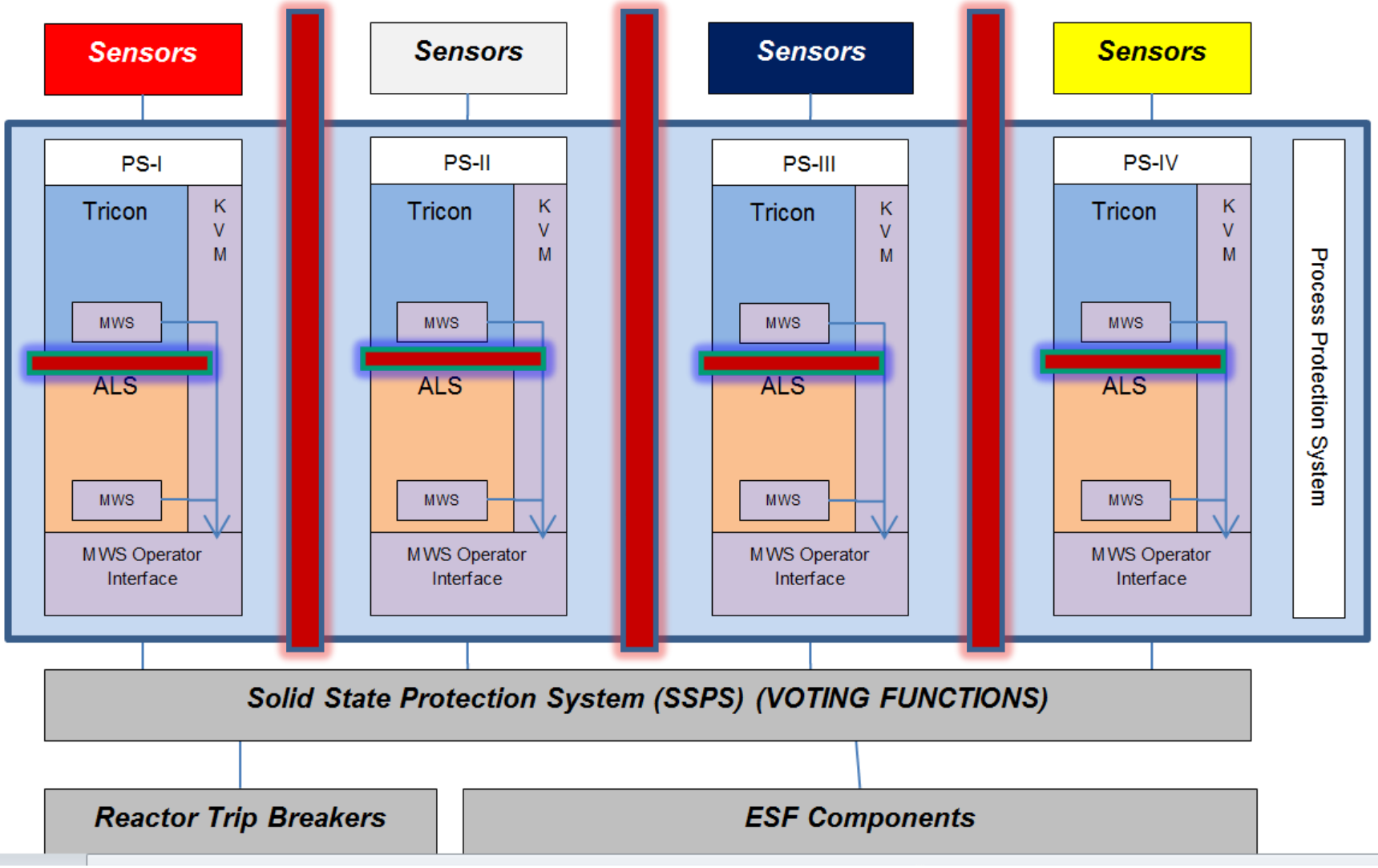


Communications Independence Evaluation

- All Communications interfaces used in the PPS design were evaluated by the NRC staff.
  These interfaces included:
  - Communications with external systems
    - Plant Computer System
    - Operator Displays and Alarms
  - Internal Communications to Maintenance Work Stations

Overview of Diablo Canyon Application

PPS System Architecture



Independence

The staff evaluated the Tricon and ALS system communication for the Diablo Canyon PPS and found they meet the guidance provided for Independence.

Control of Access

PPS Replacement Design Features

PPS Design Features to Address Control of Access Requirements

- ✓ **Access to the PPS replacement is administratively controlled by control room personnel.**
- ✓ **The PPS replacement design does not allow for remote electronic access to the Tricon or ALS platforms.**
  - The PPS Maintenance Workstations have no connections to external systems (No network connectivity).
- ✓ **Design features provide physical access controls to the PPS.**
  - The system will be located in plant vital area
  - The PPS cabinets will be locked
  - Tricon keyswitch position (other than RUN) will result in an alarm
  - Connection of the Test ALS Bus will result in an alarm

Control of Access

Review Areas

- ✓ **SDOE and Configuration Management**
  - Evaluated during the Topical Report reviews and found to be acceptable
  - The same measures were maintained for the PPS replacement application
- ✓ **Secure Development and Operational Environment**
  - Vulnerability Assessments → Security Control Requirements → Access Controls
- ✓ **Configuration Management**
  - Identification of configuration items
  - Access controls based on work responsibilities
  - Change review, approval and verification process
  - Error reporting and corrective actions program
- ✓ **Unintended/Unauthorized Changes**
  - Vendors' V&V groups performed code reviews

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Control of Access

The NRC staff concludes that the DCPP PPS replacement design incorporates features to administratively, physically and logically control access to the system, both during development and operation. These features meet the guidance for Secure Development and Operational Environment, and Configuration Management.

The NRC staff determined that the DCPP PPS system meets the criteria for control of access.

Diversity and Defense in Depth (D3) Analysis Preformed by Licensee

Eagle 21 (1993)
Assumed CCF of PPS resulting in loss of all PPS safety functions

Replacement PPS System (2011)
Assumed loss of all Functions performed by the Tricon Subsystem.

- Update to previous analysis tables
- All plant accidents and AOO's are included in the analysis
- Identifies three parameters for which there is no existing automatic diverse backup function.
  - Pressurizer Pressure
  - Containment Pressure
  - RCS Flow
- Describes ALS diversity and postulates CCF of ALS. This CCF does not result in loss of ALS assigned safety functions

Tricon Platform Diversity Characteristics

- *Three Redundant Input/Processing/ Output Paths*
- *All Redundant Paths share same software processing*

Assumed CCF of PPS resulting in loss of all Tricon PPS subsystem safety functions

ALS Platform Diversity Characteristics

– *Core Diversity*

– *Embedded Diversity*

Assumed CCF of ALS PPS subsystem does not result in loss of ALS safety functions

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Diversity and Defense in Depth
Manual Operator Action

- The new Diablo Canyon Digital Process Protection System:
  - eliminates the need to perform Manual Operator Actions as a means of coping with a software CCF within the PPS.
  - does not affect the ability of operators to perform manual actuations of safety functions.
- Manual Initiation signals are provided directly to the SSPS system which is not being modified.
  - Previously credited Manual Operator Action controls will still be available to the operators.
  - Existing component and division level actuation capability at the main control boards will be retained

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PPS System Diversity

- ***The NRC staff determined that there is adequate diversity within the plant design that the plant responses to design basis events concurrent with potential software CCF of the PPS system meet the acceptance criteria specified in BTP 7-19.***

- ***The NRC staff determined that the ALS and Tricon subsystems of the PPS are sufficiently independent and diverse from each other such that any failure of either subsystem will not result in a condition that is not accounted for in the plants accident analysis.***

- ***The DCPP PPS design includes diverse means of providing required safety functions in the event of a PPS software CCF.***

System Time Response / Deterministic Performance

- Deterministic performance characteristics for each platform were evaluated and accepted by the NRC as part of the associated platform safety evaluation.
  - Each evaluation considered system characteristics
  - The NRC staff then evaluated Application Specific Characteristics

ALS System Time Response / Deterministic Performance

- No Embedded Microprocessor Cores
- FPGA Design Does not use Interrupts
- Deterministic sequence of performing logic operations:
  1. Acquire Inputs
  2. Perform Logic Operations
  3. Generate Outputs

Tricon System Time Response / Deterministic Performance

- The Tricon application program (calculational cycle) cannot be interrupted by any of the lower priority tasks during the program execution cycle.
- Actual processing time is established during program development.
- Once application program development is complete, the cycle time does not vary as a function of calculational loading of the system.

PPS System Time Response / Deterministic Performance

"The NRC staff concludes that the DCPP PPS system's real-time performance is deterministic and known, as documented by the system performance requirements and tests performed for validation of these requirements. The NRC staff determined that the DCPP PPS system meets the criteria for deterministic and predictable performance."

Digital I&C Subcommittee Meeting

April 4, 2016

Last Open Items Closed Since Subcommittee Meeting

Safety Evaluation Open Items: Seismic Qualifications of PPS

Resolution: The In Equipment Response Spectra vs Test Response Spectra comparisons showed that Safety-Related PPS components are adequate under design basis conditions provided analysis assumptions are verified and recommended cabinet modifications are performed during plant installation of the PPS.

Digital I&C Subcommittee Comments & Discussions

ACRS Subcommittee Comments:

- Safety conclusions made for protection set I with assumption that other protection sets would be acceptable.
- References to EMI/RFI qualifications open Item
- Integrated Site Tests
- Inspection items only applicable to the ALS subsystem
- Batteries within the Tricon subsystem
- Auxiliary Feedwater system operation following Tricon system failure

License Amendment Request Status

The following schedule is based on assumption that the NRC will receive ACRS Full Committee Letter Report by September 30 and may be adjusted based on date and extent of comments received from ACRS.

• Finalize LAR Package for Concurrence	October 28, 2016
• Final review of the package by technical branches and Office of General Council (OGC)	December 9, 2016
• Issue Final LAR Package	December 30, 2016

Lessons Learned on the Digital I&C Licensing Process (ISG-06)

Introduction

- Establish a graded approach to performing Digital I&C safety Evaluations. (Tier 1, 2, and 3)
- Provide clear guidance to identify supporting document submittal requirements. (Annex B)
- Provide an evaluation process which can be performed in parallel with the system / software development processes for these systems. (Phases of review)
- Streamline the licensing process by consolidating guidance from multiple sources into a single reference that will be easy to use.

Lessons Learned on the Digital I&C Licensing Process (ISG-06)

Introduction

- The Graded Approach does not address project scope or complexity.
- Guidance to identify supporting document submittal requirements was helpful but could be expanded to address Topical Report Reviews.
- The evaluation process was performed in parallel with the system / software development processes. However, this introduced review uncertainties and resulted in many document re-submittals.
- Multiple sources of review guidance had to be considered. This led to a lengthy and complex evaluation report.

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ISG-06 Lessons Summary

- ISG-06 has significantly improved the licensing process for digital I&C systems.
- Further Improvements are being pursued as a result of lessons we have learned during the Diablo Canyon Pilot Project.
- These improvement efforts are Included in the Integrated Action Plan to Modernize Digital Instrumentation and Controls Regulatory Infrastructure.

End of Presentation

Backup Slides

Digital I&C Subcommittee Comments & Discussions

Comment: It was noted that the safety evaluation conclusions for this report were based on review of protection set I documentation with an apparent assumption that other protection sets would be acceptable.

Response: This was an initial review observation write-up which identified the report as not addressing the other three protection sets. The discrepancy was subsequently resolved and the vendor revised the activity summary report to address documentation for all protection sets and submitted software design documentation for all four protection sets. The staff reviewed the revised information and summary reports for all protection sets.

Digital I&C Subcommittee Comments & Discussions

Comment: It was noted that several references were made to an Open Item in regard to EMI/RFI qualifications for the PPS system. With this unresolved item, is was not clear how the safety conclusions were being supported.

Response: This open item was followed up with an RAI to the licensee. The response to this RAI provided sufficient information to resolve the concerns raised by this open item.

Digital I&C Subcommittee Comments & Discussions

Comment: The Safety Evaluation states that the licensee will perform SAT with interconnections between the ALS and Tricon. However, the SE also describes the testing activities performed and it seems that they did not perform integrated tests of the systems. Why was this not done during FAT?

Response: "Software Verification and Validation Plan" review portion of the evaluation report describes and evaluates test planning activities for the PPS system. This includes activities which have not yet been performed such as site acceptance tests, and installation tests. These activities are not part of the staff review for the safety evaluation.

Digital I&C Subcommittee Comments & Discussions

Comment: Why are certain inspection items only applicable to the ALS subsystem?

Response: These inspection items were derived from requirements in the ALS Topical Report safety evaluation. Each of these items identifies a specific ALS design condition which must be satisfied in order to validate the environmental qualification test results used to support the EQ safety conclusions for the ALS platform.

The EQ evaluation of the Tricon did not rely on installation specific conditions so there were no corresponding conditional requirements identified in the Tricon platform safety evaluation and the NRC staff determined that no additional inspection activities were needed for the Tricon installation.

Digital I&C Subcommittee Comments & Discussions

Comment: How are Batteries within the Tricon subsystem controlled and maintained.

Response: The Tricon PLC system has two redundant batteries located on the main chassis backplane. If a total power failure occurs, these batteries maintain data and programs on the main processor modules for a period of 6 months. The system will generate an alarm when the battery power is too low to support the system.

Digital I&C Subcommittee Comments & Discussions

Comment: Will a common cause failure of the Tricon subsystem lead to an inability of the auxiliary feedwater system to actuate.

Response: The NRC staff reviewed the Diablo Canon AMSAC and AFW system designs and has confirmed that AMSAC design includes a time delay function which ensures it remains armed and capable of initiating AFW after a plant trip when the PPS system is inoperable.

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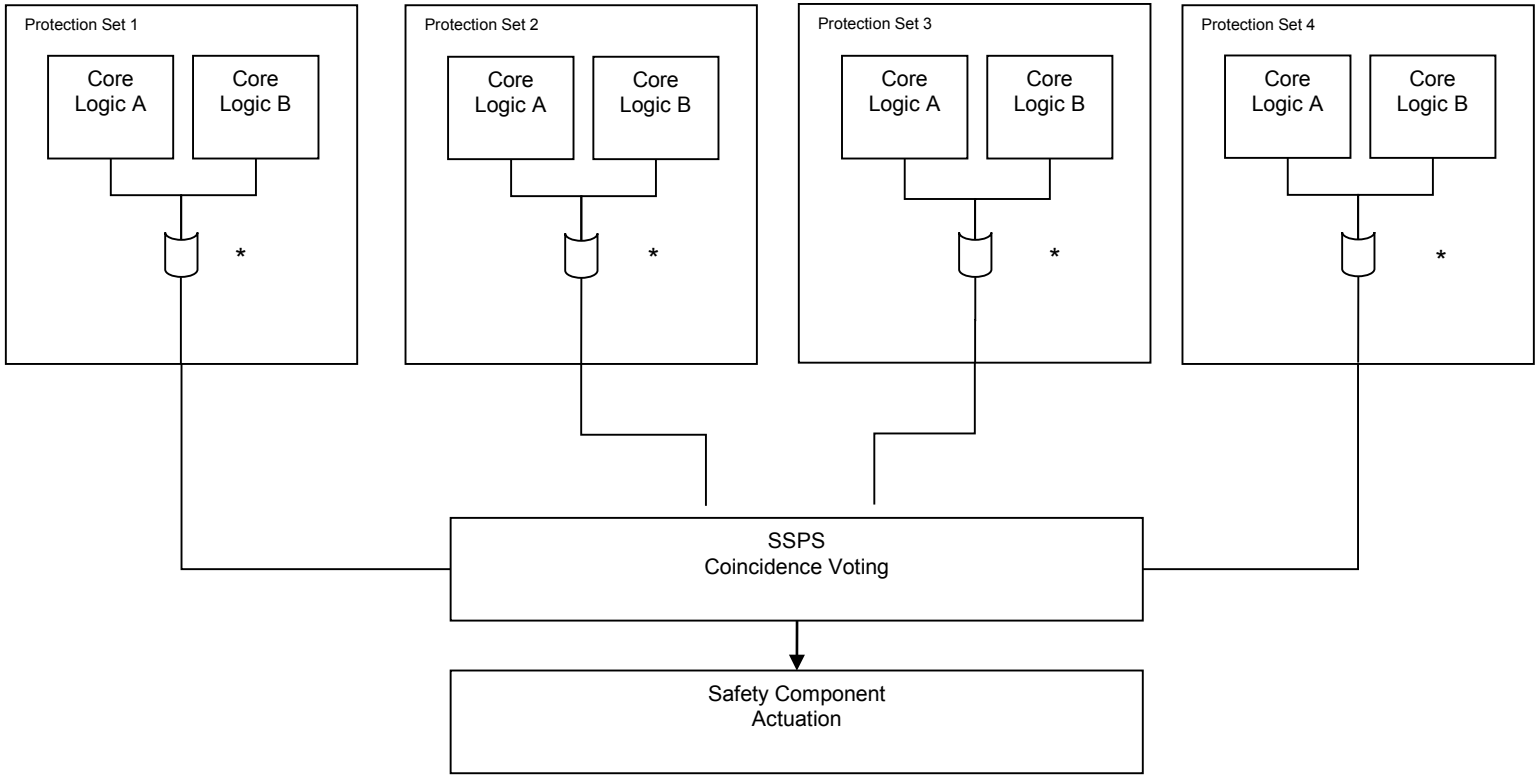
Diversity and Defense in Depth

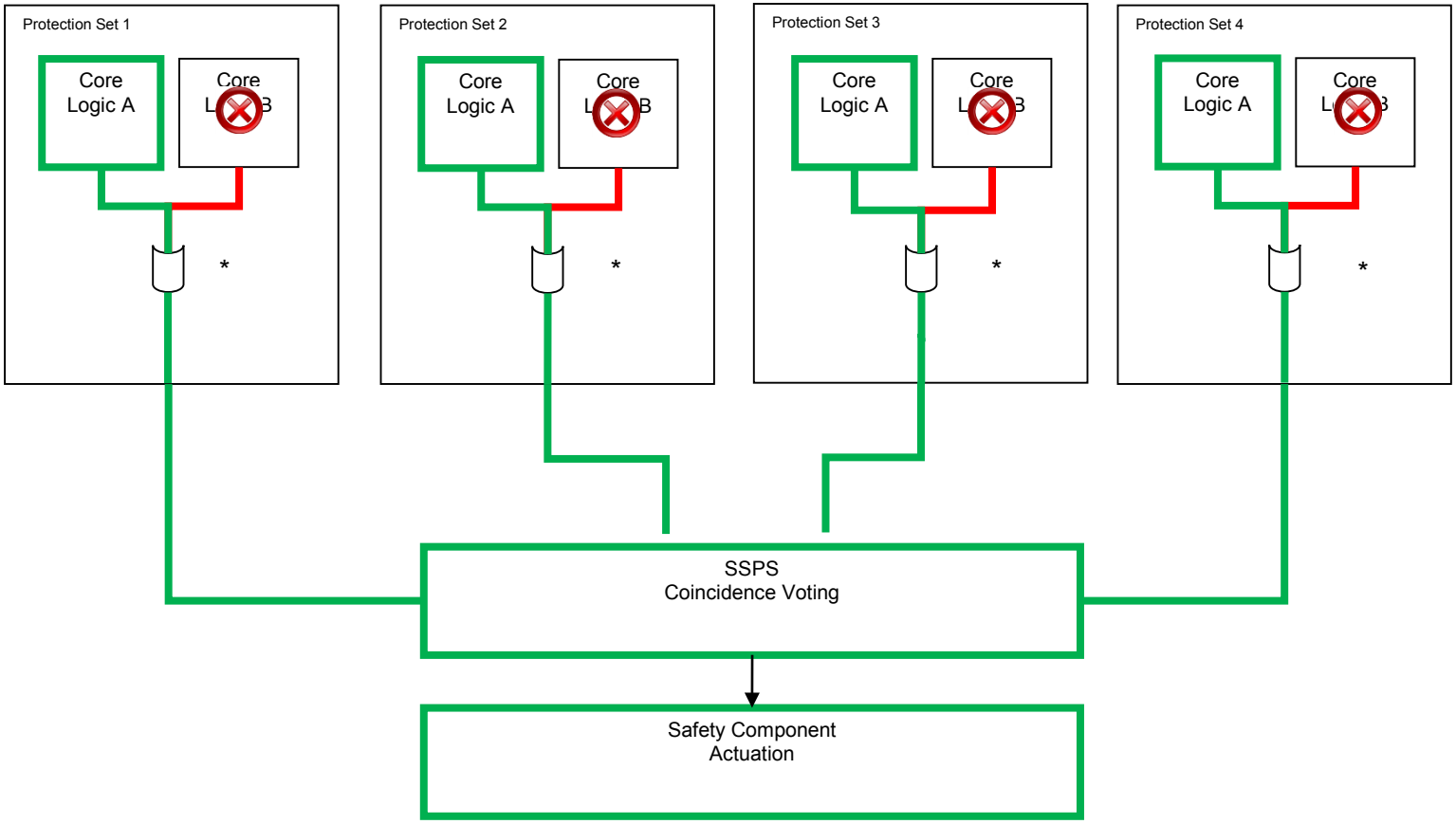
Diablo Canyon PPS Diversity



* OR function is accomplished by DO contacts in series for De-energize To Trip (DTT) or in parallel for Energize To Trip (ETT) function.

Diversity and Defense in Depth

Diablo Canyon Diversity Solution



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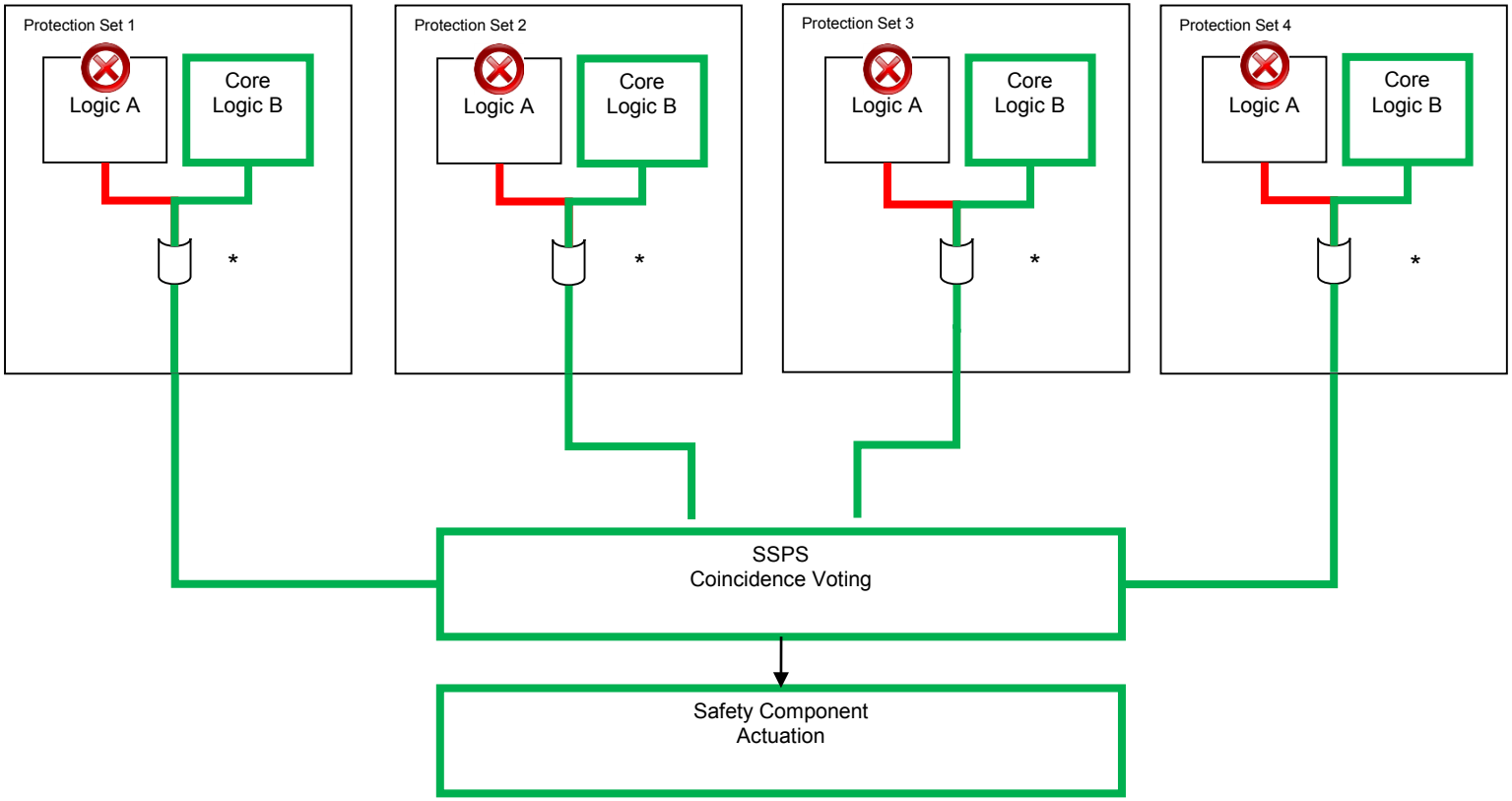
Diversity and Defense in Depth

Diablo Canyon PPS Diversity



* OR function is accomplished by DO contacts in series for De-energize To Trip (DTT) or in parallel for Energize To Trip (ETT) function.

Lessons Learned on the Digital I&C Licensing Process (ISG-06)

Lessons Learned

1) Interaction with the staff early and often in the pre-submittal phase was effective in preparing the licensee and staff for this license application.
2) Licensees and Vendors should request a Phase 0 meeting prior to LTR submittal to review Enclosure B and agree upon what documentation is required for the LAR or Topical Report submittal.

Lessons Learned on the Digital I&C Licensing Process (ISG-06)

Lessons Learned

1) The documentation tabulation of Enclosure B was effective in identifying information needed by the staff to start its technical review of the LAR.
2) Use of a Phase 1 documentation Compliance Matrix facilitated an efficient LAR acceptance review.

Lessons Learned on the Digital I&C Licensing Process (ISG-06)

Lessons Learned

1) ISG-06, Enclosure B should be enhanced to provide guidance on required information for a platform LTR submittal.
2) ISG-06 should be enhanced to promote remote, electronic websites/reading rooms for use to the extent practical to determine what proprietary information should be submitted on the docket.
3) Phase 2 document lists should be enhanced to acknowledge unavailability of certain documents until late stages of development.

DTE Energy®

Fermi 2 – License Renewal

ACRS Full Committee Meeting
September 8, 2016

Keith Polson

Site Vice President

Introductions

Representing Fermi 2 Nuclear Power Plant:

- Keith Polson, Site Vice President
- Larry Peterson, Director Engineering
- Randy Breymaier, Manager Performance Engineering
- Lynne Goodman, License Renewal Project Manager

"Our number one asset at DTE is our people"

Personnel In Attendance

ISI Programs & Service Water Marc “Al” Brooks	Reactor Vessel Programs Erica Mullen	Fatigue Management Mike Williams
Fire Protection / Fire Water Mike Yeager	Civil / Structural Tim Hoffman	Operations Greg Strobel
FLEX Response Kevin Burke	Inaccessible Cables Jeff Auler	Fuel Storage Mike Lake
New Programs & Implementation Brett Gallatin	License Renewal Project John Tibai	License Renewal Project Kevin Lynn
MEP Manager, Engineering Projects Stephen Berry	Counsel Jon Christinidis Dave Repka	Plant Support Engineering Kendra Hullum-Lawson
Structural Integrity Associates Terry Herrmann	General Electric Hitachi Brian Frew	Project Contractor - Entergy Alan Cox

Agenda

• Introductions	Keith Polson
• Plant Design, Plant History, and Current Status	Larry Peterson
• License Renewal Application Project and Closed SER Open Item	Lynne Goodman
• Aging Management Programs	Randy Breymaier
• Closing Remarks	Keith Polson

Plant Design

Larry Peterson

Director, Engineering

Plant Design

- Fermi 2 is a 3486 MWt Boiling Water Reactor
- Producing approximately 1170 MWe
- GE BWR 4 with a Mark I Containment

- Fermi 2 shares site with Fermi 1, a fast breeder reactor in passive SAFSTOR

Plant Design

- Cooling Water
  - o Lake Erie provides makeup water to General Service Water, which discharges into a Circulating Water Reservoir
  - o Two natural draft cooling towers
  - o RHR Complex is Ultimate Heat Sink
    - Two reservoirs (one per division) with induced draft cooling towers over each reservoir
- Electrical Design
  - o 120 kV switchyard for Division 1 power
  - o 345 kV switchyard for Division 2 power
  - o 4 Emergency Diesel Generators (EDGs) – 2 per division
  - o Combustion Turbine Generator (CTG) 11-1 station blackout power supply – Division 1

Plant History

- Operating License – March 1985
- Commercial Operation – January 1988
- 4.2% Thermal Power Increase – September 1992
- 1.64% Measurement Uncertainty Recapture (MUR) Uprate (56 MWt) – February 2014
- Independent Spent Fuel Storage Installation (ISFSI) – 2014
- Fukushima modification for FLEX and Fuel Pool – 2015

Fukushima FLEX 2 Storage Facility

Plant Investment

In anticipation of extended operation, DTE Energy is making a large investment in Fermi 2:

- Generator replacement
- Pumps and motors
- Process computers
- FLEX and hardened vent
- Spent fuel racks
- Aging management programs
- Plant modifications for safe, extended operations

License Renewal Application Project

Lynne Goodman

License Renewal Project Manager

License Renewal Application Project

- Submitted application April 24, 2014
- Developed using NUREG-1801 (GALL) Rev. 2
- Identified the Aging Management Programs (AMPs) to manage aging effects during Period of Extended Operation (PEO)
- Incorporated Fermi 2 and industry operating experience
- Fermi 2 subject matter experts and management were involved with the application development, review and oversight
- Addressed LR-ISGs 2012-02, 2013-01 and 2015-01 following License Renewal Application development
- Used Enercon/Entergy as experienced LRA contractor

OI 4.3.3-1 Effects of Reactor Water Environment on Fatigue Life Resolution

Issue:

NRC staff questioned how average temperatures were calculated in the Environmentally Assisted Fatigue (EAF) evaluations performed by DTE and whether revised temperature calculations would impact the conclusions and selection of Sentinel locations.

Response:

EAF calculation for six locations were revised to address the open item. Results were submitted to the NRC on January 22, 2016. No changes in sentinel locations due to this issue. Effects of EAF will be managed by the Fatigue Monitoring Program.

This item was closed in the final SER.

Aging Management Programs

Randy Breymaier

Manager, Performance Engineering

Aging Management Programs

- The Performance Engineering organization owns license renewal implementation at Fermi 2.
  - License Renewal has a Program Owner and the owner is part of the License Renewal Core Team
- All existing and new programs have owners
- During the License Renewal Process, commitments were made against both the existing and new AMPs. These commitments are in the UFSAR Supplement (Appendix A of the LRA).

Aging Management Programs

Aging Management Programs (AMPs)

- 45 total AMPs
  - 12 new AMPs to be developed
  - 32 existing AMPs, enhancements will be made to 22 AMPs
  - 1 existing AMP was deleted (Boraflex Monitoring)
- Of the 44 remaining AMPs
  - 32 AMPs consistent with GALL, Rev. 2
  - 11 AMPs with exception to GALL, Rev. 2
  - 1 AMP plant-specific (Periodic Surveillance and Preventive Maintenance)

Implementation

- Planning in progress to implement enhancements and new programs
- Program and procedure development in progress
- Inspections have started, with approximately 80 specific inspections to be performed during the next refueling outage in spring 2017 (RF18)
- Long term plan for station includes license renewal implementation activities plus projects to support safe operation of the plant for 20 more years

Closing Remarks

"Fermi 2 has been providing safe, reliable, environmentally clean, cost-effective power to our customers for over 25 years."

United States Nuclear Regulatory Commission

Protecting People and the Environment

Advisory Committee on Reactor Safeguards Full Committee Meeting

September 8, 2016

Fermi 2

Safety Evaluation Report (SER)

Lois M. James, Project Manager

Office of Nuclear Reactor Regulation

Presentation Outline

- **Overview of Fermi 2 license renewal review**
- **Closure of Open Item**
  - OI 4.3.3-1 Effects of Reactor Water Environment on Fatigue Life
- **Conclusion**

Review Milestones

- License Renewal Application Received April 30, 2014
- Safety Evaluation Report (SER) with Open Items issued January 28, 2016
- ACRS License Renewal Subcommittee meeting held March 2, 2016
- Final SER issued July 12, 2016

SER Section 3

3.0.3 - Aging Management Programs

Applicant's Original Disposition of AMPs	Final Disposition of AMPs in Final SER
• 11 new programs – 11 consistent • 33 existing programs - 9 consistent - 18 consistent with enhancements - 5 consistent with enhancements and exceptions - 1 plant specific with enhancements • 1 new program added - 1 consistent with exceptions	• 12 new programs – 10 consistent – 2 consistent with exception • 32 existing programs - 6 consistent - 16 consistent with enhancements - 3 consistent with exceptions - 6 consistent with enhancements and exceptions - 1 plant specific • 1 existing program deleted

Open Item 4.3.3-1

4.3.3-1 – Effects of Reactor Water on Fatigue Life

- **Issue**:
  - The methods used to determine the average transient temperatures to calculate F_{en} factors were not consistent with the guidance in NUREG/CR-6909, Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials.
- **Applicant's Response**:
  - Identified six locations where average transient temperatures were used to calculate F_{en} factors.
  - Recalculated the F_{en} factors for five of the six locations to become consistent with the guidance in NUREG/CR-6909.
  - Found the remaining location (core ΔP nozzle) to be consistent with the guidance in NUREG/CR-6909.
- **Conclusion**: Fatigue Monitoring Program is acceptable.

Conclusion

On the basis of its review, the staff determines that the requirements of 10 CFR 54.29(a) have been met for the license renewal of Fermi 2.