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1 U.S. NUCLEAR REGULATORY COMMISSION

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3 THE GENERIC LETTER ON GRID RELIABILITY

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5 PUBLIC MEETING/WORKSHOP

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7 MONDAY,

8 JANUARY 9, 2006

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11 The meeting was held in the Waterford

12 Suite of the Hyatt Regency Bethesda, 7400 Wisconsin

13 Avenue, Bethesda, Maryland, Chip Cameron moderating.

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

2 (8:30 a.m.)

3 MR. CAMERON: Hi. My name is Chip
4 Cameron. I'm the Special Counsel for Public Liaison
5 within the Office of General Counsel at the Nuclear
6 Regulatory Commission, and it's my pleasure to serve
7 as your facilitator for this meeting today and
8 tomorrow, and I just want to welcome all of you.
9 I have a few brief comments about meeting
10 process before we get into the substance of our
11 discussions today, and I just want to talk a little
12 bit about what the focus of the meeting is, the format
13 of the meeting, some real simple ground rules, and
14 just give you a real quick agenda overview.
15 In terms of the focus of the meeting,
16 you're going to hear more about this from Mr. Jim
17 Dyer, who is the Director of the Office of Nuclear
18 Reactor Regulation at the NRC, but at least three
19 questions, I think, for you are:
20 Are the objectives of the generic letter
21 on grid reliability clear?
22 Are the information or is the information
23 requested by the questions in the generic letter, are
24 they clear what information the NRC needs?
25 And is it clear what the tie is between

1 the objectives of the generic letter and the questions
2 seeking information?
3 And the NRC is going to give you
4 information on all of this and then we want to hear
5 any comments that you might have, any questions that
6 you might have on all of this.
7 In terms of format, we're going to be
8 basically having some presentations on the generic
9 letter. We're going to have some panels of various
10 organizations, and we're going to go to you for
11 discussion and questions.
12 We built some redundancy into the agenda.
13 For example, there are going to be panels on the
14 generic or on the questions in the generic letter, but
15 also we have a panel tomorrow, an industry panel with
16 NEI and INPO and the NRC, and obviously that's going
17 to revisit some of the issues that we talk about.
18 Today we also have a general question and
19 answer question at the end of tomorrow morning so that
20 we can revisit some issues that you may not have had
21 a chance to explore more fully today.
22 In terms of ground rules, when we do get
23 to the discussion part of the agenda, if you have
24 something that you want to say, please signal me, and
25 I'll try to come out with the cordless mic. We also

1 have microphones in the audience, but I would hope
2 that we will not have people queuing up at the mics.
3 That's why I'll try to get to you with cordless.
4 When I do get to you, please introduce
5 yourself to us, your name and affiliation, if
6 appropriate.
7 I would ask that only one person talk at
8 a time for two important reasons. One is that so we
9 can give our full attention to whomever has the floor
10 at the moment, and secondly, so that we can get a
11 clear transcript. We have our stenographer with us in
12 the back of the room. His name is also Chip. We're
13 making it easy for you. For future meetings, just
14 assume the facilitator's name is Chip and the
15 stenographer's name is Chip. So all very simple.
16 That's sort of a joke, I guess.
17 (Laughter.)
18 MR. CAMERON: But not a very big one.
19 When we do get to the panels, and the
20 panels are going to go right through in their
21 presentations, we're going to try to keep the
22 presentations brief, about 15 minutes each. When
23 we're done with the panel presentations, we're going
24 to give them an opportunity to ask questions of each
25 other or comment before we go out to you for comment.

As much as possible, and it may be a little bit difficult in this type of meeting, I'd like to try to follow discussion threads. If someone in the audience raises an issue, before we move on to a different issue, I'd like to check in and see if anybody has any additional views on that particular issue.

Please try to be concise. I think we have plenty of time, but there's a lot involved with this issue. So just try to be concise in your comments and questions.

We will have a parking lot up here that I'll keep. There may be questions that come up that are not relevant to the topic we're discussing at the time, but are relevant to something later on in the agenda. We'll put those up there and make sure that we come back to those when we get to the appropriate part of the agenda.

There are going to be cards, comment cards that the NRC staff will make available to you. Those serve two purposes. One is if you have a comment on some of the issues you hear that you don't get to bring to the floor, the NRC staff will have the benefit of that comment.

I'd like to encourage everybody to speak

1 up rather than using the cards to get your comment
2 before us, but obviously if we run out of time at some
3 point, please put your comments on there.
4 You can also put a question on there, and
5 we'll make sure when we get to the general discussion
6 area tomorrow morning before we close, we'll go
7 through those questions and see if there's any that
8 have not been answered and then we'll use them to
9 answer those questions.
10 And finally, in terms of the agenda, we're
11 going to have some introductory remarks this morning
12 from Mr. Jim Dyer, who is the Director of Nuclear
13 Reactor Regulation, and from Mr. Brian Sheron, who is
14 the Associate Director of Energy and Safety Systems in
15 our Office of Nuclear Reactor Regulation.
16 There's an opportunity for some clarifying
17 questions to both Jim and Brian after that, and then
18 we're going to move to an overview of the generic
19 letter, and we have Mr. Paul Gill from the NRC staff
20 who's going to give you that overview. Again, an
21 opportunity for clarifying questions.
22 We do have specific items on the agenda
23 for the questions in the GL. So we don't necessarily
24 want to get into a big discussion after Paul's
25 presentation, but we do want to give you the

1 opportunity to ask some questions there.

2 Next we have risk insights. The NRC and

3 EPRI are going to present that. After that discussion

4 we'll go to transmission systems, and we have an

5 excellent panel who's going to present on that.

6 We're going to try to adjourn at four

7 o'clock today. At 11:30, there's a lunch break. In

8 the morning, we have a break scheduled for 10:20; in

9 the afternoon a break at 2:45; and tomorrow we're

10 going to get started at 8:30.

11 I just would thank you all for being here.

12 It's going to be an interesting day and a half, and

13 with that I'm going to turn it over to Jim Dyer.

14 Jim.

15 MR. DYER: Is this thing hooked up? Okay,

16 good. The reason I asked is there's a cable sitting

17 here.

18 (Laughter.)

19 MR. DYER: I just said, "Oh, well, I might

20 be tough."

21 First of all, let me say thanks for coming

22 out on a Monday, particularly those of you who

23 traveled in from afar.

24 Just to get a profile of what my audience

25 is today, is there a Federal Energy Regulatory

1 Commission member here, a member of FERC?
2 (Show of hands.)
3 MR. DYER: Well, managed to come in.
4 Good. Welcome.
5 How about North American Electric
6 Liability Council? Anybody?
7 (No response.)
8 MR. DYER: Any members of transmission
9 system operators, independent system operators?
10 (Show of hands.)
11 MR. DYER: Somebody in the back, the
12 middle, the end. Good.
13 How about utilities, NRC licensees or
14 otherwise? What's the utility reps.?
15 (Show of hands.)
16 MR. DYER: Good. How about NRC? How many
17 of the NRC staff have we got?
18 (Show of hands.)
19 MR. DYER: Okay. Good. Look like a good
20 representation, which is important for a workshop.
21 The intent of my opening remarks is really
22 just from a high level to talk a little bit about what
23 this generic letter, why we're doing it, what this
24 generic letter means to me, and then I'm going to
25 leave and let you try to figure out if we're in

1 alignment in that.

2 But I think the actual purpose of this

3 meeting was really outlined in a Commission staff

4 requirements memorandum to us that outlined it. It

5 really asked us to look at three questions:

6 What is intended by the generic letter

7 questions?

8 What does the NRC expect from the answers?

9 And how do we anticipate using this

10 information?

11 And the challenge we have is with the

12 proposed generic letter right now is to take a look at

13 whether we need to make changes to that, you know,

14 conduct this meeting, decide whether we need to make

15 changes to the generic letter to accomplish what we

16 want to, and then get back to the Commission to

17 support getting the generic letter issued by the end

18 of the month.

19 And that goes to allowing the utilities

20 and NRC licensees time to respond and then for us to

21 get back and to be prepared for the summer of '06.

22 So just with that in mind, let me give you

23 a couple of my high level views, I guess, to frame the

24 discussions today. And first of all, you know, this

25 workshop is necessary. The Commission SRM that

1 directed the staff, the only question about that was
2 whether we held it before or after we issued the
3 generic letter and based on schedule and talking to
4 the Commission, you know, we're doing it now before
5 we've issued the generic letter so that you have the
6 opportunity to influence how we can adjust the
7 questions in that.
8 And on a higher level, we're still
9 working, you know, in the post August of 2003
10 environment, whether it was the grid drop of the
11 northeast and into the -- I've been into the Midwest,
12 and we had our lessons learned. We've had a number of
13 action items coming out of that.
14 But the one question that still is before
15 me is whether our current regulations for off-site
16 power are adequate in the current deregulated
17 environment, and that's a question that, you know, we
18 asked ourselves that the NRC staff took a look at and
19 reviewed, and we came to the conclusion they are.
20 You know, off-site power is considered in
21 licensing of the plan as preferred power source, and
22 it provides defense in depth to the on-site power
23 supply. So it has a regulatory purpose, and it's a
24 question of our regulations, and we really looked at
25 three regulations that are outlined in the generic

1 letter.

2 One, the general design criteria of Part

3 50 that are translated from operating reactors into

4 your technical specifications and your licensing

5 basis; the maintenance rule, and particularly, 10 CFR

6 5065(a)(4) for risk management; and lastly, the

7 station blackout rule, 10 CFR 50.63, which concerns

8 coping studies and procedures for recovery.

9 You know, one of the things we have

10 though, one of the questions we have though is whether

11 our understanding of the regulation reflects the way

12 the industry implements these regulations, and making

13 sure we're in alignment is the purpose of this, of the

14 generic letter.

15 And in the generic letter when we worked

16 through the Office of General Counsel and to get the

17 interpretation of the regulations and to make sure

18 that our understanding as articulated in the generic

19 letter is consistent with OGC's, you know, is

20 supported by the Office of General Counsel, and it is,

21 and so that sort of lays out the way we view the world

22 for off-site power with respect to these three

23 regulations.

24 Now, we've got the results from the TIs

25 that we conducted prior to the summer of '05 and the

1 summer of '04 where we went out and we took at some of
2 these areas, and that's what leads us to question
3 whether or not the implementation really reflects the
4 way we understand the regulations and our views on
5 compliance with what the regulations are.
6 And I'll acknowledge that we may not have
7 been asking the right questions, that we may have
8 miscommunicated. We may not have looked under or
9 asked the right people in the organization to get it,
10 and our decision was to go forward with this generic
11 letter in order to facilitate that general
12 understanding of whether or not implementation is as
13 the NRC sees compliance.
14 Let me talk a little more specifics in the
15 four areas that are outlined in the generic letter.
16 The generic letter is framed. It has eight questions
17 in the four areas concerning the three regulations.
18 So let me just give you my views on what the NRC needs
19 are and what we don't need from the generic letter in
20 these areas.
21 And the first area is the general design
22 criteria and the technical specifications which govern
23 off-site power operability and operational constraints
24 on nuclear power plants. You know, what the NRC needs
25 to know is that if your off-site power source is

1 unreliable that you'll declare it inoperable, enter it
2 into the action statement and take actions to fix it
3 and report it.
4 You know, nuclear power plants need off-
5 site power when they've lost the output from the
6 reactor and the generator. If the utilities -- if the
7 nuclear power plant is the only one holding up the
8 grid, then you're not operable, our view. If there's
9 another plant on the grid, another supply onto your
10 grid that if it's lost would cause you to trip and the
11 off-site power to go away, then we don't think they're
12 operable. That's not a reliable source of off-site
13 power.
14 But one of the things we're not asking you
15 to do is to come up with a double contingency, as I
16 think I've heard discussed or I've been questioned in
17 other avenues where you have to figure out how much of
18 -- you know, whether or not a loss of another plant
19 and then taken on top of that another loss of your
20 plant.
21 Unless the two are interconnected, we're
22 not looking for a double contingency or, you know, two
23 layers -- that's it -- of defense in depth.
24 We're also not requiring you to use
25 specific codes or real time contingency analysis

1 methods. I think those are regulated by FERC, NERC
2 and chosen by the transmission system operators'
3 independent system operators.
4 So we're not trying to influence. You
5 have to influence your transmission system operator.
6 If, in fact, that's a question and the utilities can't
7 get good information, we'd like to know about it.
8 We'll address our counterparts in FERC and talk to
9 NERC about whether or not there's adequate
10 communications now.
11 But our understanding is that the system
12 operators in that have the information and do that.
13 The maintenance rule, 10 CFR 5065(a)(4)
14 requires power plant licensees to both assess and
15 manage risk of maintenance activities. This includes
16 considering whether in the grid conditions, and it's
17 outlined in Reg. Guide 1.182 and endorses NEI 9301.
18 You know, what this regulation requires
19 licensees to do is to be able to know the predicted
20 grid conditions for the duration of a planned
21 maintenance outage of a critical piece of equipment.
22 From the NRC's perspective, recently research
23 finalized their NUREG on grid activities, grid
24 reliability, and in our view the grid is more unstable
25 in the summer months and you really shouldn't be

1 scheduling extended outages for diesel generators,
2 batteries, and the turbine driven pumps during the
3 time frame when your grid is predicted to be unstable.
4 That's for long-term planning.
5 Also, the NRC recognizes that when you do
6 schedule things that emerging conditions occur, that
7 a grid you thought would be stable, something happens
8 and it doesn't. What we really expect then is that
9 you'll know about it when it happens and have a Plan
10 B, you know, which may be to reschedule the
11 maintenance, to accelerate the completion of it, or to
12 back out based on what's the best interest in safety.
13 You know, the third area is the station
14 blackout rule with respect to the coping capabilities
15 where each plan is required to cope with the station
16 blackout for a specific period of time based on the
17 vulnerabilities that are expected of that plan.
18 One of those vulnerability considerations
19 is loss of off-site power frequency. You know, what
20 we need to know is that plants are updating their
21 analysis to make sure they're in the right bin and
22 have the right coping abilities, given the conditions
23 of their local grid around them and that they consider
24 all of the loss of off-site power events, that they're
25 not arbitrarily excluding events because of the

1 potential root cause.

2 And the last area is also the station

3 blackout rule, and that also requires plant staff

4 procedures to restore off-site power and using nearby

5 sources. You know, what the NRC needs to know is that

6 the deregulated environment doesn't prevent those

7 kinds of recovery procedures from being implemented

8 and that they're still current under the current

9 environment.

10 You know, in the deregulated environment

11 that we're operating in today, the utilities, you

12 know, they're not an island. They don't control all

13 these different factors anymore. There's a number of

14 different players, and that's why I'm very pleased

15 that we've got, you know, FERC and the transmission

16 system operators and a wide variety of utilities in

17 our licensees and in our staff.

18 You know, what we need to do is to have a

19 healthy discussion, and I'll be the first one to

20 admit, you know, I read through the generic letter

21 again this weekend after I had spoken to NEI and taken

22 a look at it from a different perspective, and I think

23 we need to fill in some of the questions.

24 So from my perspective, the NRC shouldn't

25 be dug into the wording as it is right now. If the

1 intent is to get to a healthy exchange of information
2 and communication about how the grid is managed by the
3 nuclear power plant licensees to the NRC, it's not us
4 trying to infringe ourselves and get into managing the
5 grid ourselves, but it makes sure we have to have a
6 healthy discussion and dialogue about how that occurs.
7 So I wish you the best in the next two
8 days. I think it's a very important meeting. I think
9 what we need to do is to try to get to, you know, a
10 simple understanding of what's expected on the NRC's
11 part and understanding what the kinds of answers that
12 we're going to get and have a good dialogue about that
13 so that when the written submittals come in later this
14 year and it gets close to the summer months, that we
15 can have the assurances and I can assure the
16 Commission that we're ready for any kind of
17 challenging grid summer conditions.
18 So with that, let me just turn it over to
19 Brian and let him make some opening remarks.
20 MR. SHERON: Good morning. I don't have
21 too much more to say than what Jim has already told
22 you. I share his thoughts completely in terms of the
23 purpose of the workshop and everything.
24 For those of you who don't know me, I'm
25 Brian Sheron. I'm the Associate Director for

1 Engineering and System Safety. I guess it would be
2 easier if I told you my name is Chip, right?
3 (Laughter.)
4 MR. SHERON: Anyway, I want to reiterate
5 that the principal goal of the workshop is for
6 everyone to have a common understanding of the
7 questions contained in the generic letter. Because of
8 concerns that were expressed by the industry, the
9 Commission issued a staff requirements memorandum as
10 Jim said on December 20th that instructed us to hold
11 a public workshop to clarify the questions contained
12 in the generic letter.
13 I want to point out this is not an
14 opportunity. This is not an additional comment period
15 for the generic letter. I mean, that has come and
16 gone. This is a workshop to help clarify what's in
17 the letter.
18 If changes are needed, as Jim said, to the
19 letter to clarify what we're looking for, we will
20 revise the letter accordingly, but I just want to
21 reiterate that we're not back in the public comment
22 period.
23 We plan on issuing the generic letter no
24 later than January 27th of this year, and we're also
25 making preparations to issue a temporary instruction

1 to our inspectors that will provide guidance for
2 performing inspections in the area of off-site power.
3 We're going to review the results of these
4 inspections, and we'll determine whether nuclear power
5 plants are prepared for continued safe operation
6 during the summer of 2006.
7 Let me digress a second here. It was
8 actually because of deregulation in the electric
9 industry and as well as the operating events in the
10 past few years, including the August 14th, 2003 East
11 Coast blackout. The reliability of the grid has come
12 into question.
13 Our initial assessment is that our current
14 regulations remain adequate, and I think Jim pointed
15 out the three that we believe apply here, GDC-17, the
16 station blackout rule, and the maintenance rule.
17 However, we believe that additional
18 actions are required to provide assurance that the
19 licensees remain in compliance with the regulations.
20 This is not a new concept. Okay?
21 As times change, as the situation changes
22 in nuclear plants, we reexamine our regulations for
23 whether they're still relevant, whether they still
24 apply. In many cases they still apply, but what we
25 need is because of changing situations in the

1 industry, we need further assurance that compliance is
2 still -- you know, that plants are still complying
3 with the regulations.
4 And for that reason sometimes we believe
5 that because of different circumstances, licensees
6 have to take additional actions. As I said, these
7 regulations are embodied in GDC-17, which is electric
8 power systems; 5065, the maintenance rule; and 5063,
9 the station blackout rule.
10 Either licensees need to provide us with
11 further assurance of a reliable off-site power supply.
12 Now, remember, a generic letter is just a request for
13 information under 50.54(f). Okay? It is not a
14 requirement. It just seeks information, and really
15 what we're asking you is we're saying that we are
16 questioning whether or not you are still in compliance
17 with these regulations for the following reasons, and
18 we outlined them in the generic letter.
19 And so what we're asking you is we're
20 saying if you still believe that you're in compliance,
21 then you need to tell us why you believe you're in
22 compliance, but if you agree with these concerns that
23 we've articulated in the generic letter, we are
24 proposing that there are some actions that we think
25 are necessary that will provide the assurance that you

1 are in compliance, and you need to tell us whether or
2 not you intend to take these actions or, if not, then
3 what actions do you intend to take to demonstrate
4 compliance and to address the staff's concerns, or if
5 you're not going to take actions, to explain why you
6 don't believe any actions are necessary.
7 We will take that information then and we
8 will decide whether or not we believe you've made a
9 sufficient case for compliance or whether we need to
10 take further regulatory action.
11 But I do want to emphasize that this is a
12 generic letter and it's a request for information.
13 It's not imposing any new requirement.
14 As I said, either licensees need to
15 provide us with further assurance of reliable off-site
16 power supply, which is the focus of the generic
17 letter, or we may need to revisit past decisions that
18 were made based on the assumption of a reliable off-
19 site power supply.
20 For example, extended diesel generator
21 allowed outage times where licensees have come in and
22 made, using risk arguments based on the reliability of
23 off-site power that they can go from 72 hours, for
24 example, to a 14-day allowed outage time, and we need
25 to go back. We may have to go back and revisit and

1 say is that still a valid assumption to make that the
2 off-site power remains reliable enough to warrant this
3 kind of a tech spec change.
4 The other thing we're obviously concerned
5 about, and I think Jim alluded to it, is the seasonal
6 variations in the likelihood of losing off-site power
7 and whether licensees need to take further actions to
8 make sure, for example, that you're not taking diesels
9 or turbine driven pumps or batteries or the like out
10 of service during periods when there's probably a much
11 higher likelihood of losing off-site power, for
12 example, in the summer months when there's a lot of
13 electrical storms, when there's hurricanes that are
14 bearing down on the coasts and so forth.
15 We need to make sure that the plants are
16 at their maximum readiness during these periods.
17 I want to reiterate we understand -- you
18 know, I've heard some concern that we were trying to
19 regulate the grid, and I want to emphasize that we
20 understand our limits of authority as a regulatory
21 agency, and we are not attempting to regulate the
22 grid.
23 But we want to make sure that we
24 understand what the reliability of the grid is so that
25 we can take appropriate actions with regard to how you

1 operate your plants.

2 To minimize stress in this area that may

3 be caused by interfacing, the staff will continue to

4 work with the Federal Energy Regulatory Commission to

5 insure that the two regulatory bodies are fully

6 coordinated. In fact, our Commission is planning to

7 meet with the Federal Energy Regulatory Commission in

8 the near future, although I don't think a date has

9 been actually set yet.

10 In closing, I just want to remind you

11 NRC's regulatory responsibility is to insure nuclear

12 power plant safety. We believe issuing a grid

13 reliability letter and ultimately reviewing the

14 licensee responses will allow the staff to determine

15 if licensees are adequately complying with the

16 regulations.

17 With that, Chip, I'm finished. We'll turn

18 it over to you if there are questions.

19 MR. CAMERON: Okay. Thank you, Jim.

20 Thank you, Brian.

21 We may not have Jim and Brian for the

22 entirety of the meeting. So we wanted to give you an

23 opportunity to ask any questions you might have based

24 on the remarks that you heard from both Jim and Brian

25 this morning.

1 And let's go back to this gentleman, and
2 we need to get everything into the microphone so that
3 we have it on the transcript, and if you could just
4 introduce yourself to us, sir.
5 MR. ALEXANDER: Hi. I'm Steve Alexander.
6 I'm with the Maintenance Rule Group at the NRC, and
7 actually I was just here to answer questions in case
8 there are any beyond what Paul Gill says about the
9 maintenance rule.
10 MR. CAMERON: Okay. Thank you very much.
11 Any questions for Jim and Brian based on
12 what you heard this morning?
13 Okay. Alex, please introduce yourself.
14 MR. MARION: Alex Marion, NEI.
15 I'm getting the sense that the NRC has
16 already drawn some conclusions on the performance of
17 the grid in terms of reliability. Is there any data
18 that's been published that's been shared for peer
19 review?
20 MR. CAMERON: Okay. Thank you, Alex.
21 Jim or Brian, on data, and we may be
22 getting into that in more depth later on.
23 MR. DYER: I don't have the details.
24 MR. RAUGHLEY: That's part of a
25 presentation later this morning. NERC/P is giving us

1 some data, and we've worked with them to analyze that.
2 We'll be showing some of the results.
3 MR. CAMERON: Okay. This is Bill Raughley
4 from NRC staff.
5 MR. RAUGHLEY: Bill from NRC research
6 staff.
7 MR. CAMERON: Okay. So we'll put that in
8 the parking lot.
9 MR. DYER: Alex though I will say that I
10 think that as I said before, I think we had a research
11 study that's been out, and I think you've commented on
12 it. We referred to it in the draft stages at the last
13 Commission meeting where our review of loss of off-
14 site power events since 1997, it has changed.
15 They're, you know, grid centered versus plant
16 centered, and the duration has changed, and that has
17 had some influence on us.
18 Again, you know, the initiating events,
19 one of the action items we took away after the August
20 2003 blackout, you know, the power plants performed
21 well, but we took a look at what if. What if there
22 had been extended diesel outages? What if? And we
23 asked ourselves the question do we have assurance that
24 that's the way the plants are always going to operate
25 and always the conditions going to be and if the

1 conditions occur as well as what can we do to enhance
2 the communications to make sure that there's an
3 understanding if the grid does get into an unstable
4 condition, that the power plants are going to know
5 that.
6 And so that's sort of the background that
7 led us to where we're at right now, but as far as
8 coming up with a conclusive risk argument that says
9 that we have to demonstrate to show that this is
10 absolutely positively necessary, I don't think we need
11 to do it, and like I said, we've got some information
12 we're going to share today.
13 MR. CAMERON: Okay. Thanks, Jim.
14 MR. SHERON: Chip, if I could.
15 MR. CAMERON: Go ahead, Brian.
16 MR. SHERON: I wanted to bring in one
17 thing on that, which I think has at least influenced
18 me a little bit, and that is that, you know, a lot
19 of times the NRC gets criticized for being a day late
20 and a dollar short in terms of waiting for something
21 to happen before we take action. You know, we are
22 well aware that, for example, the licensing form which
23 NEI sponsored back in November, one of the senior
24 executives in his opening remarks pointed out that I
25 think the East Coast was going to have negative

spinning reserves in about two or three years. Because this was obviously a discussion about new reactors.

But he expressed a concern which I think kind of struck a nerve with me, and that was that he said, "I don't know where the power is going to come from."

And so we need to be prepared for the fact that, in fact, the reserves, the spinning reserves, are not what they used to be, and I think when we get into summer months and stuff, grids are going to be strained even further than what they were in the past, and that's of some concern.

And so I think that's something else that motivates and drives us to want to have further assurance of reliable off-site power.

MR. CAMERON: Okay. Thanks, Brian.

Let's go right here.

MS. WEBER: My name is Jennifer Weber, Tennessee Valley Authority on the transmission side of things.

In working closely with our nuclear plants, in making sure we're communicating with each other, one of the biggest things that I find is that we need to have a common vocabulary. So I wanted to

1 mention four key words that are used throughout the
2 generic letter and in the discussion that have a
3 different meaning to the transmission side of things
4 than they do to the nuclear house and to perhaps
5 suggest that these terms be defined very clearly in
6 the generic letter and in our discussions.
7 The first term is "unit trip." It is used
8 throughout the generic letter. The grid always
9 operates so that their system is secure for loss of a
10 unit, but I think perhaps in the generic letter you're
11 referring more to a design basis event, such as a LOCA
12 shutdown or a full load rejection.
13 Those are very different events in terms
14 of grid impact from a simple unit trip.
15 The second term is "off-site power," and
16 I think that needs to be distinguished clearly between
17 an external source of power to the plant versus a
18 qualified off-site power source for tech spec
19 purposes. Those are different.
20 To be a qualified off-site source, you
21 have to postulate, again, a design basis and insure
22 that your voltage would hold up in that postulated
23 event. That's different from the physical loss of an
24 external power source.
25 And then the third and fourth words are

1 "reliable" and "unstable." Reliability and stability
2 have very specific definitions in the NERC side of the
3 house in transmission. Like reliability means we can
4 lose a large building or a large line, and we maintain
5 positive control of the grid. That has a very
6 specific definition.
7 Stability has to do with oscillations and
8 system recovery to steady state following a
9 disturbance. So I think those words are used by
10 general people in a different sense than we understand
11 them in implementing them on the grid.
12 MR. DYER: Thank you.
13 As you were saying, you know, as you go
14 through it, the devil is really in the details, you
15 know, and I think that's the real benefit of this
16 meeting, is if we can make sure we've got -- you know,
17 what we're transmitting is what you're receiving and
18 what you transmit, what the licensees transmit back to
19 us is what we receive, you know. It's those kinds of
20 details that are going to be important.
21 MR. CAMERON: Okay, and thanks, Jennifer.
22 I put common vocabulary in the parking lot, and I'm
23 going to ask all of you to be a guide for me about
24 when is the most appropriate time to address, during
25 the next day and a half, to address those issues, but

1 we do have it in the parking lot.

2 Yes, sir.

3 MR. KLECKLEY: Good morning. I'm Phil

4 Kleckley, and I'm in the transmission planning group

5 at the South Carolina Electric and Gas Company.

6 And while we're talking about definitions,

7 I was going to wait until we had a little more

8 discussion, but maybe this is a good time to go ahead

9 and do this.

10 In referring to operability of the off-

11 site power supplies, not being a nuclear person, I

12 don't have much of a background in the usage of the

13 term, but in reading through some of the materials,

14 I'm getting a little bit of vagueness in what I'm

15 understanding it to mean.

16 Does this mean that the off-site power

17 supplies are reliable to the point that it is not

18 necessary to go to the on-site power supplies, or does

19 it mean that if the off-site supplies are lost, they

20 will become available before some other requirement is

21 met?

22 Thank you.

23 MR. CAMERON: Okay. I think that I don't

24 know if, Brian or Jim, you want to say anything or

25 Paul at this point, but certainly it's going to be an

1 issue that we're going to come back to later on.
2 MR. DYER: I think the former. I think
3 the first thing you said, but I --
4 MR. GILL: Jim, I think I'll elaborate on
5 that when I get it in my discussion.
6 MR. CAMERON: Okay. Good. So we won't
7 lose that one. Okay. We'll come back to it.
8 Let's go to this gentleman right here.
9 MR. ROSENBLUM: Dick Rosenblum from
10 Southern California Edison. I'm the CNO there now,
11 but I used to be the head of the transmission and
12 distribution business for the last ten years.
13 Brian's comment about negative reserve
14 causes me to ask that people think about one more
15 definitional difference that I think is going to
16 become important, and it's one not commonly made.
17 There's a difference between grid reliability or grid
18 operability or whatever the defined term we choose to
19 use, which for a transmission person means you've got
20 the right frequency, the right voltage, adequate VAR
21 (phonetic) support, and a bunch of other thing.
22 In-service reliability, a term I have just
23 made up, which means your customers have lights,
24 that's a distinction not commonly made by anybody.
25 Brian talks about negative spinning reserve. The way

1 you get spinning reserve back is you show a bunch of
2 your customers off.
3 The grid is a happy camper through all of
4 that. So I think as we go forward, and I'm not trying
5 to lecture here; you know, it sounds like it; we need
6 to start differentiating between those two things.
7 The nuclear power plant requires grid reliability.
8 Service reliability is immaterial and is, in fact,
9 used to create grid reliability, and that is a
10 distinction that has not historically been made by
11 either the nuclear people or the transmission people
12 in the way I just described it, but is important to
13 this issue.
14 MR. CAMERON: Thanks for offering that
15 distinction, Dick.
16 Anything else before we go on? We'll go
17 right here and then we'll go right over there. Yes,
18 sir.
19 MR. LEAKE: Hi. I'm Harvey Leake with
20 Palo Verde.
21 I think the two points that Jim made were
22 pretty important for the industry one. The industry
23 is not asking for an analysis of double contingencies,
24 and second, that there's not a new requirement for use
25 of real time contingency analyzers.

1 So my question is: is this going to be
2 clarified anywhere in writing?
3 MR. CAMERON: Okay. Thank you.
4 And just before you answer that, Jim, I
5 just want to check in and make sure that the two
6 things that you heard are correct assumptions about
7 what you said.
8 MR. DYER: Yeah, I think we don't require
9 a double contingency, but the one caveat I made was
10 but if you have an off-site supply or a supply to the
11 grid another unit supply -- you're going to get me
12 tangled up now because I know it's probably butchering
13 whatever the vernacular is in the transmission
14 world -- but there's another supply, you know, besides
15 the nuclear plant that will, in fact, take down the
16 grid and cause the nuclear power plant to trip. That
17 would be the largest contingency.
18 The same thing with the real time
19 contingency analysis. We're not specifying a code, I
20 mean, but I'm glad the Federal Energy Regulatory
21 Commission is here, and my understanding is that the
22 transmission system operators are all using literally
23 state of the art codes for our purposes that can
24 predict or do the kinds of analysis that's needed for
25 the NRC regulatory needs in the utilities.

1 If we're wrong, then we need to understand
2 that, but I think you're right.
3 MR. CAMERON: Okay, and the final point,
4 Jim, about whether these issues will be clarified in
5 the generic letter.
6 MR. DYER: Yeah, I thought they were, but
7 I think there's a footnote on the real time
8 contingency analysis code, and it explains -- it
9 doesn't say we're not going to do double contingency,
10 but it does talk about what we are going to ask for,
11 which is the single largest contingency.
12 MR. CAMERON: Okay, and that point that
13 you raised is before us, and it's one of the things
14 that the staff will look at after this meeting.
15 Let's go to Bruce.
16 MR. POOLE: Yeah, my name is Bruce Poole.
17 I'm from the Federal Energy Regulatory Commission, and
18 I guess what you have to say is everyone is judged in
19 NERC on meeting standards. Okay? And so you always
20 have your contingencies because that's set up in the
21 standard.
22 Some people run a computer program that
23 does an on-line contingency analysis all the time, but
24 not everybody does that. Okay? So not every utility
25 will be doing that currently. There are some that are

1 developing systems now that will, and there are some
2 that haven't converted or aren't using that.
3 So I just want you to know that when you
4 say real time contingency analysis, not everybody does
5 that, but they all manage to meet NERC reliability
6 rules by some other method. They may have a program
7 that's not running all the time. It may run every
8 five minutes or every ten minutes. Okay? But it may
9 not be real time.
10 MR. DYER: I think our main thrust is that
11 when the ISO or transmission system operator realizes
12 or analyzes that there's a problem, that there's
13 communications to the utility and what the utility
14 does with that information.
15 MR. CAMERON: Okay. Great. Let's go for
16 one more comment/question, and then we're going to go
17 to Paul. This is a good preview and prelude to some
18 of the issues that are important for discussion.
19 MR. ATTARIAN: Thank you.
20 George Attarian, Progress Energy and
21 Chairman of Working Group 4.6 on off-site power IEEE.
22 My question is that in the last three
23 years the nuclear industry has not been, so to speak,
24 in a hole. There's been a lot of things that are
25 happening. What weight did the staff give to the

1 generic letter to the actions that have been taken by
2 the INPO SOERs and the other actions that are in
3 progress right now by the industry?
4 MR. CAMERON: Great. Thank you.
5 MR. DYER: From my perspective, I think
6 that you're right. The industry has done a lot; the
7 NRC and the industry have both done a lot to
8 understand what's going on, what the conditions are.
9 Clair is here from the Institute of
10 Nuclear Power Operations to participate, and he'll be
11 able to shed some light on that.
12 I think what INPO has done has gone, in
13 particular, beyond, you know, what our regulations
14 are. What we want to know is that the floor is there,
15 you know, what we consider the minimum stuff
16 acceptable.
17 So it's not our intent to regulate to what
18 INPO is expecting because it goes beyond, but it is a
19 subset or below that that we feel our regulations
20 require to regulate at that level.
21 And so hopefully, and I've talked to
22 George Fellgate (phonetic) at INPO, and that what INPO
23 is doing would cause the utilities to exceed what
24 we're doing, but we need to know that that floor is
25 there.

1 MR. CAMERON: Okay. Thanks, Jim, and we
2 do have Mr. Clair Goddard with us who is going to be
3 on a panel tomorrow and will specifically address what
4 the implications are for the generic letter from what
5 INPO is doing, and I'm sure we'll hear about that
6 before tomorrow, too, but I would just thank Jim and
7 Brian for being here this morning, and I'm sure
8 they'll be here as much as they can throughout the
9 next day and a half, but I think we're ready to move
10 on to the overview.
11 Mr. Paul Gill from the NRC staff.
12 Just let me ask. Brian, Jim, do you have
13 anything else that you want to say before we go on?
14 MR. DYER: No.
15 MR. CAMERON: Okay, great. Thank you.
16 MR. DYER: I've got to run.
17 MR. CAMERON: Okay. Thank you, Jim.
18 MR. GILL: Good morning. My name is Paul
19 Gill. I'm the technical lead on the generic letter,
20 and I'm going to use slides to discuss the generic
21 letter.
22 Mr. Dyer and Dr. Sheron have already laid
23 out, I think, to a great extent what I was going to
24 talk about. So what I'm going to do is talk in a
25 little more detail of the overview and the reasons

1 that they laid out.

2 So if I could go to my first slide,

3 please. Go to the next one, Objectives.

4 Okay. I think you heard the objective

5 this morning from Mr. Dyer and Dr. Sheron, but let me

6 follow up on that. The objectives of the generic

7 letter is essentially one to seek information from you

8 in terms of assessing where we are in terms of meeting

9 out regulations. So there's one objective is to

10 verify compliance.

11 And the second objective I would say is

12 that based upon that information, to see if we do need

13 to do something different, such as maybe rulemaking,

14 if that is the case.

15 So we need that information to assess

16 within our agency to find out where we are, and what

17 I want to do also here is to -- my objectives for

18 discussing the generic letter is to provide you what

19 we think is the regulatory basis for asking the

20 questions that we are asking; also to tell you what's

21 intended by these questions, what kind of information

22 we are looking for; and also what we would expect in

23 terms of answers, trying to help you along in terms of

24 what we are looking for rather than send you a very

25 general question and then get responses which may

1 require further elaboration and requests for
2 additional information. So we want to minimize that.
3 We'd like to make it a very smooth transition in terms
4 of getting responses that we understand in terms of
5 what our needs are.
6 And also how are we going to use this
7 information?
8 Next slide, please.
9 We are asking questions. Jim mentioned
10 four areas, but in essence actually, you know, if you
11 got up and looked at it, it's really three areas,
12 although we could make it into four areas. The one
13 is, of course, into the off-site power system, and I'm
14 going to get into the off-site power system to kind of
15 give you the basis, the regulatory basis, and to
16 determine its you heard the words "operability" or
17 "availability," and so on. So I'm going to talk about
18 that as we go through my discussion.
19 And the second area is the maintenance
20 rule, and again, in terms of using looking at the
21 grid, are you taking the grid into when you make risk
22 assessments? Before you take risk significant
23 equipment off, as well as while you are in the
24 maintenance of that equipment.
25 And the third area is station blackout,

1 and I'm going to talk about that a little bit to give
2 you some background, what the requirements were, what
3 your licensing basis is regarding station blackout,
4 and why we think at this time we need to kind of look
5 at it again, given the operating experience as to
6 whether we are still in compliance or not.
7 So those are the three areas that we're
8 going to look at.
9 Now, let me go to the next slide, which
10 will talk about the regulatory requirements, and I'm
11 going to go through each area, first dealing with the
12 off-site power system.
13 You heard mentioned GDC-17. On this slide
14 I've listed the other GDCs, or the general design
15 criteria, that talk about off-site power system, and
16 these other GDCs are the 33, 34, 35 all the way to 44,
17 and they all have requirements for off-site power
18 system.
19 And let me kind of sort of paraphrase
20 what's in those GDCs and you can look at the 10 CFR 50
21 and read in more detail.
22 And what this talks about is -- the next
23 slide -- it talks about the requirements in these
24 GDCs, and these are required for ESF type systems, and
25 it says that for off-site electric power system

1 operation and for on-site electric power system
2 operation, the system safety function can be
3 accomplished assuming a single failure.
4 What it's saying in these guides, general
5 design criteria, is that you have to have an off-site
6 power system available, assuming the on-site is not
7 available, as well as -- the emphasis being on
8 "and" -- have an on-site power system available
9 assuming the off-site is not available.
10 And the single failure, of course, applies
11 to the on-site system because we don't take a single
12 failure in the off-site system.
13 So if you look at these design criteria,
14 it's saying that you have to have both available. So
15 it's not one or the other.
16 I've heard the argument or discussion from
17 people, well, gee, I got my diesels. My diesels work
18 fine. So what's the problem with the off-site?
19 Well, the problem here is that if you
20 strictly look at the design criteria, it's requiring
21 that both be operable at the same time. So what we
22 want to make sure is given the operating experience,
23 do we have an off-site system that is operable and
24 available to perform its safety function? Okay?
25 So that's the regulatory basis for the

1 off-site power system, as well as if you look at GDC-
2 17.
3 Next slide, please.
4 Now, GDC-17, I've kind of pulled out a
5 small subset from the criteria that's listed in the
6 GDC-17 because it talks about the number of off-site
7 power sources into the plant and the design aspects of
8 it, but it also has provisions where it says that you
9 should minimize the probability of losing electric
10 power from any of the remaining supplies, you know,
11 that are coming into the plant to power the safety
12 buses. Okay?
13 And it specifically talks about loss of
14 power from the transmission network. Now, I've heard
15 the arguments, and I think it will be resolution of
16 comments. I think a number of commenters said, "Well,
17 GDC-18 is only a design guide. Well, that is true,
18 but I will then argue that any design, the adequacy of
19 any design, including the power system, can only be
20 determined by reference to the conditions under which
21 it's going to be operating. Okay?
22 Now, whether the system meets the design
23 criteria can only be determined by analyzing the
24 system response under the most extreme operating
25 conditions. So what good does it do to have a design

1 that we think is adequate, but when you actually need
2 it, it's not there?
3 My point being that, sure, there are
4 design requirements, but along with it, you have the
5 operating requirements. Now, the operating
6 requirements are imbedded in the technical
7 specifications. So for those of you that are familiar
8 with the technical specifications for a nuclear power
9 plant, it talks about, you know, the limiting
10 condition of operation should you use one line or two
11 lines. Okay?
12 So that's what we want to emphasize.
13 That's what we want to find out. Given the grid
14 conditions today -- and I'm not going to argue whether
15 the grid is reliable or unreliable at this point. I
16 think the discussion following my presentation will,
17 you know, make a point that grid, you know, of course,
18 is -- that we see on the horizon some issues with the
19 grid.
20 The point that I want to make here is are
21 you in compliance with your technical specifications
22 if you know that the grid is not going to be there or
23 the off-site power is not going to be there if you
24 have a unit trip.
25 I know we had talked about what's a unit

1 trip. In this case it would be a nuclear unit, and so
2 the point being that, you know, are we in compliance
3 or not. Are you meeting your licensing basis or not?
4 Are you meeting the tech spec or not?
5 So the regulatory basis for the Questions
6 1 through 4 that are in the generic letter basically
7 are based upon the GDC's criteria, the technical
8 specifications that, you know, are part of your
9 licensing basis. You know, I'm talking about the
10 nuclear power plant licensees now.
11 Okay. Let's go to on the next slide, and
12 I will come back and talk about, you know, in a little
13 more detail the off-site power system when we get to
14 the questions.
15 Now, let me just come back to the off-site
16 power system. I forgot about this slide. If you look
17 at this slide, we talked about this RTC, real time
18 contingency analysis, and so on.
19 Now, let's go back to the bold where the
20 4(d) regulation. Okay? All the utilities were
21 vertically integrated utilities. The transmission
22 folks were part of the same group that were the
23 nuclear unit or the fossil units. They all talk to
24 each other openly.
25 And one of the licensing bases or one of

1 the criteria that if you go back and look at our
2 standard review plan, NUREG 800, Chapter 8, it lays
3 out very specific evaluations that you have to make
4 for the off-site power system, and it talked about
5 this contingency analysis. Okay?
6 And here Jim talked about single
7 contingency versus double contingency.
8 Now, if you review your, say, licensing
9 basis, you'll find in the U.S. FAR that the analysis
10 that you perform at that time during the license was
11 to look at three areas. One was the loss of the
12 largest single supply, and in most cases it most
13 likely is going to be the nuclear unit, or it could be
14 some other unit that is even larger than the nuclear
15 unit.
16 You have to assume that failure of that
17 unit and show that the off-site system is available
18 and functional. Okay. I'll use those words instead
19 of being "operable," or you look at the most critical
20 transmission line and assure us or assure yourself
21 that there's adequate voltage or adequate, you know,
22 power available to power the safety buses.
23 And the third criteria was the largest
24 load, that if you lost the load rejection, for
25 example, that you still would have off-site power.

1 Now, the question in terms of being
2 available, operable, or functional, what we have to
3 look at is for most plants today we have the degraded
4 grid wall ditch (phonetic) set points because that's
5 what's going to cause you to lose off-site power or
6 going to cause you to lose power to the safety buses.
7 Because if your voltage dips below the degraded grid
8 wall ditch set points, you're going to lose off-site
9 power.
10 So the real key issue from our perspective
11 is do you have adequate voltage in the switch yard,
12 which is the off-site power system, to power the
13 safety buses?
14 So that's one simple way of looking at or
15 assuring adequate off-site power system. Okay?
16 Now, let's go to the slide that talks
17 about the maintenance rule, and, Steve, thanks for
18 coming, for answering any questions on the maintenance
19 rule since I'm not an expert in that.
20 The maintenance rule requires under (a)(4)
21 to perform, you know, risk evaluation or do a risk
22 evaluation before you take equipment out of service,
23 and it was alluded that now we are doing a lot of
24 maintenance at power. For example, diesels from three
25 days Dr. Sheron mentioned, and now we have going to 14

1 days when the unit is at power or when the nuclear
2 power plant is supplying -- the grid is supplying
3 power.
4 And the question is that you need to look
5 at the maintenance. You have to look at the -- before
6 you take that diesel out or any other what we call
7 risk significant equipment out, that, indeed, the grid
8 risk is factored into your risk evaluation, not only
9 when you go into the maintenance, but you should also,
10 you know, keep on top of it while you're maintaining
11 it to see if conditions change.
12 So that's an area where we have, you know,
13 questions. We want to have some information. So we
14 can better understand how you are implementing that
15 provision of the maintenance rule with respect to the
16 off-site power system.
17 Next slide, please.
18 Now, in the station blackout area, if you
19 look at the statement of considerations, the EDG or
20 the emergency diesel generators, which are the on-site
21 power sources, its reliability or -- I'm sorry -- its
22 availability was considered to be very, very low, and
23 that was based upon only looking at the corrective
24 maintenance that was done at power for the emergency
25 diesel generators. And as indicated here, it was less

1 than one percent.

2 Now, in terms of station blackout rule,

3 the target reliability that is factored into the rule

4 is either .975 or .95.

5 Now, you know, this low availability that

6 was assumed in the station blackout determined those

7 targets. Now, what if your current unavailability is,

8 say, three percent or something different? Then you

9 say, you know, the question is going to be how are you

10 meeting your .975 reliability target if your diesel is

11 not available to you for three percent.

12 So that there's a concern now that not

13 only the diesels that you have. You're taking them

14 out for ten, 14 days, say, during a refueling cycle

15 and doing maintenance at power. What is the real

16 unavailability of those diesels?

17 And as I understand it, and somebody can

18 correct me, that according to the industrial guide,

19 preplanned maintenance unavailability is not counted

20 into the overall unavailability of the diesels. So it

21 would seem to me that perhaps the unavailability will

22 be something that if you factor that in it might be

23 even higher than what it is being reported.

24 I think I'm going to take a little bit of

25 water. My mouth is all drying up.

1 And also under the station blackout rule,
2 the assumptions that we made, for example, to
3 determine the coping duration, and again, the station
4 blackout rule is not a very easy rule. It's very
5 cumbersome, and in the sense that before you determine
6 your coping duration you have to go through a lot of
7 analysis of calculations.
8 And one of the items in determining the
9 coping duration is looking at the off-site power
10 characterization. Let me put it that way. In other
11 words, you look at the off-site power system and
12 determine what kind of off-site power system you have.
13 In the station blackout rule, it gives you three
14 grades: P-1 through P-3. In other words, from the
15 very best to the very worst, and based upon what group
16 that a specific site or plant fell into the off-site
17 power group determines, along with emergency diesel
18 generator reliability target that was chosen, as well
19 as, you know, some other factors. You determine what
20 would be your coping duration.
21 That is, that if you had a station
22 blackout, for how long would it take for you to
23 recover off-site or on-site power? So that is a
24 coping duration that you have to maintain the plant in
25 safe shutdown condition.

1 And most of the plants according to
2 station blackout rule either fall into four hours or
3 eight hours. So let's assume that you have a plant
4 that has a four-hour coping duration, and its original
5 determination was made upon the off-site power group
6 being either P-1 or P-2, and the question that we are
7 asking in this area is based upon the operating
8 experience, given the loss of off-site power events
9 which you will hear later on about, what if you now
10 become a P-3 group? What would be the coping
11 duration?
12 And if you look at the guide, the Reg.
13 Guide 1.55 or the NUMARK (phonetic) 8700, you're
14 coping duration might be higher than four hours. It
15 may be eight hours or 16 hours.
16 So given that, now the question is that
17 from our perspective is the four-hour coping analysis
18 adequate to keep that plan safe if you don't expect to
19 recover that off-site or the on-site, you know, either
20 from four hours to eight ours.
21 Now, for four-hour plants, the majority of
22 them depend upon natural circulation. So the analysis
23 has been done for those plants that are four hours
24 using the natural circulation, that they have enough
25 water. Okay? They have enough battery for four

1 hours.

2 So now from the staff's perspective, what

3 if your duration became eight hours? Do you have

4 enough battery? Do you have enough water?

5 And I don't think, you know, we can sit

6 back and say, "Gee, everything is going to be all

7 right." Maybe it would be all right, but I think the

8 question needs to be answered, and we have to ask this

9 question: that if, indeed, your original coping

10 duration is still being maintained, if it is, then

11 your analysis is okay. And if your coping duration is

12 now changed, then you need to ask yourself, you know,

13 do I need to do something different now.

14 So that's where the questions in the

15 station blackout area are being driven from. Now, we

16 are concerned that if your coping duration changes or

17 increases -- let me put it this way -- then your

18 current analysis is no longer valid, and you need to,

19 you know, tell us one way or the other whether it is

20 or not.

21 But the first step you have to do is to

22 determine whether your coping duration is impacted or

23 not. Okay? So that's a real safety concern there.

24 All right. Chip only gave me what, about

25 45 minutes to an hour? So I need to move fast here.

1 Let's go into the generic letter itself
2 and talk about some of the questions and hopefully
3 later on in the workshops or in the clarification
4 period we can answer some of your questions.
5 In the first area, off-site power, there
6 are four questions as I mentioned, and those four
7 questions basically go:
8 Question No. 1 goes to the agreements with
9 your transmission system operator or your ISO, since
10 various terms are being used, for monitoring off-site
11 power. That's kind of the handshake arrangement that
12 we are asking you about. What kind of arrangement you
13 have with your transmission system operator in terms
14 of communicating with him, or the transmission system
15 operator communicating with you about the grid.
16 Now, as I mentioned earlier, your
17 licensing basis established the contingency analysis
18 that was done during the license. That is your
19 licensing basis.
20 Now, as we know, today many of the
21 transmission systems are separated from generation or
22 even for those utilities that have not gone to
23 deregulation, I believe your generation is separated,
24 although be part of the same company.
25 Now, as I understand it, the grid is being

1 operated -- let me put it this way -- in a different
2 manner than was originally envisioned. As I said, in
3 the old system, you did a contingency analysis, and
4 you operated the grid within the bounds of that
5 contingency analysis.
6 Today I don't think we can say that
7 definitively, that the grid is being operated within
8 the bounds of that contingency analysis. Well, that's
9 the question we are asking you. You need to tell us
10 whether it is or not.
11 Now, remember the old contingency analysis
12 assumed, you know, the flow, okay, megawars,
13 megawatts, whatnot, how many lines and so on. Maybe
14 physically nothing has changed, but certainly I think
15 you will agree the flows have changed, and if the
16 flows have changed, your analysis I would think
17 changes, and that was the case at Callaway back --
18 what was it? -- 1999. They had excessive flows
19 through their system which were not part of,
20 originally analyzed. Now, the question is where else
21 is this happening. We know that, you know, of course,
22 the famous blackout. I won't go there.
23 But the question that we want to know, and
24 I think rightfully so, we need to ask you that is your
25 grid being operated within the bounds of your

1 analysis, or I could put it another way. Is your
2 analysis still valid?
3 And you need to tell us whether it is or
4 not. And we talked about the programs or, you know,
5 the tools that are available today. Mr. Poole
6 mentioned that some utilities are using, you know,
7 these tools; some are not. But even if you don't have
8 on-line tools for a given, say, plant, that if you're
9 using off-line tools, that you can periodically look
10 at different scenarios or your transmission system
11 operator will look at, you know, different scenarios
12 and operate the grid, and I assume that that's what
13 they're doing, is operating the grid within the bounds
14 of that analysis.
15 The real question is: does that now match
16 up with the licensing basis type of analysis that was
17 done during, you know, the original license?
18 So the first two questions for the off-
19 site power system deal with those two areas. One is,
20 you know, communication with your transmission system
21 operator. Second is what kind of tools is your
22 transmission system operator using, and how often it
23 is updated.
24 How often is communicating to you as a
25 nuclear power plant operator what's going on in the

grid? Okay?

And the two other questions within that off-site power system is now talking about the availability or operability of the off-site power system. Okay?

So next slide, please.

And I'll come back to those questions in a little more detail, but for the maintenance rule, again, let me mention that there are two questions in that area where we are asking in terms of the risk evaluations as a part, you know, of your overall risk for taking an important piece of equipment that you need for mitigating either a loss of off-site power or, you know, any other occurrence on the plant and maintaining that.

How often are you updating that evaluation while the equipment is out for maintenance? Okay?

Let's go to Slide 13.

Okay, and this goes back to now off-site power system again. The first question says: describe any formal agreements with the transmission system operator to promptly notify the nuclear power plant when conditions of the surrounding grade are such that the greater voltage below tech spec requirements or a loop could occur following a trip of

1 the reactor.

2 And I could have very well said trip of

3 the reactor or a critical transmission line or largest

4 load rejection. But our focus was that we believe

5 that the nuclear unit or the nuclear generator

6 probably is most likely the largest generator on the

7 system, and what we want to know is if that generator

8 is providing support to the grid for maintaining that

9 voltage, now if that trips, are you still going to

10 have adequate voltage, you know, in the switchyard to

11 power the safety buses?

12 Now, if you don't, if the voltage is not

13 adequate, your degraded voltage relays are going to

14 isolate or trip the off-site power and go on to the

15 emergency diesel generators.

16 Now, you know, if you've got both diesels

17 ready and available, great. Okay. That's what we

18 want, but what if you have a diesel on the floor,

19 you're doing a major overhaul, and the other diesel

20 fails to start and you've lost off-site power?

21 Now you're into station blackout, and I

22 don't think we want to go there. Okay? Now, I hear

23 arguments. "Yeah, we've done analysis. We're okay

24 for station blackout," but I don't think, you know, we

25 want to force, challenge our systems through where,

1 you know, something might work, might not work. Okay?
2 So the first question basically is saying
3 in terms of these agreements that you have with your
4 TSO to let you know when things are not so good on the
5 grid, as well as for you when you're taking something
6 out when it might impact the grid. So it's a two-way
7 communication. Although we don't have any -- we can
8 regulate that as I understand it, but certainly we can
9 ask the question what are you doing as a nuclear power
10 plant operator to keep on top of this, meet your
11 licensing basis.
12 And this particular question has -- now we
13 could have left that question as a general question
14 and gotten responses, which may or may not have been
15 adequate, and then we would have to go out for a
16 request for additional information. So we decided
17 that it would be better and more effective in terms of
18 asking you very specific honed questions in terms of
19 what information we're seeking.
20 So that's why you see these subparts to
21 these questions. We have broken each question down in
22 terms of the information that we want you to send back
23 to us.
24 So we will ask the question: was the
25 required notification timed for example, that if your

1 transmission system operator, you know, whatever tools
2 he's using, determines that the grid is in stress
3 condition, how long does it take for him to let you
4 know?
5 Okay. And how often does he do that or
6 how often do you check with your transmission system
7 operator?
8 Okay. So those subpart questions are
9 essentially to help you and help us get the
10 information from you that we need.
11 Now, the question is that if you don't
12 have any of these arrangements with the TSO, then one
13 of the subpart questions is tell us how do you think
14 you're meeting your licensing basis if JDC-17?
15 So you know, you might think there are a
16 lot of questions, but actually many of these questions
17 are very simple, straightforward answer and this was
18 essentially to make it more efficient for you and for
19 us to get the information.
20 The question as I mentioned talks about
21 the tools. How do you insure that the off-site system
22 will remain operable following a trip off your unit or
23 nuclear power plant?
24 And we are not mandating. You know, you
25 used the reliably centered -- I mean, these modern

1 tools, real time contingency analysis and so on, but
2 given that your grid is changing, let me say hour by
3 hour or maybe day to day -- I don't know. Okay? It
4 depends on what part of the country or what part of
5 the grid you are associated with -- that if you don't
6 use these tools, and I'll just throw this questions up
7 to you, tell me how you're going to find out what's
8 happening on that transmission system. That is now
9 supplying power to your plant.
10 Now, you know, I think it seems to me that
11 if the grid conditions are changing, then you have to
12 use a tool that tells you what's going to, you know --
13 or get heads up as to if type scenarios, that what if
14 I lose that unit or if I lose that transmission line,
15 what's going to happen?
16 And from a nuclear power plant operator
17 perspective, you know, you would want to know. Do I
18 have that off-site available to me or not?
19 Now, remember in the context of off-site
20 power we always refer it to as preferred power. That
21 is the most reliable preferred power source that you
22 can gave for the nuclear power plant.
23 Now, if that is not going to be preferred
24 in the sense that it is not -- you know, again, I'm
25 kind of a "what if" type of conjecture here -- if that

1 power source becomes unreliable, then maybe we ought
2 to start thinking in terms of, gee, we can rely on the
3 off-site power. Maybe we ought to look at something
4 different. You know, maybe we need to go to another
5 power source that we can rely upon.
6 So it seems to me that, you know, in the
7 resolution of the comments I saw a lot of questions
8 about, you know, RTCA. You know, it's not required by
9 your regulations. Sure, it's not required by
10 regulations, but tell me how you're going to do it.
11 Okay? I'll throw it back at you.
12 You know that your grid, for example --
13 and, again, it may or may not be true in every case --
14 your grid is not being operated in the manner on which
15 your license is based, and I went through the
16 licensing basis.
17 Now, you tell me: is the grid being
18 operated in the bounds of that analysis that was
19 submitted to get the license? Okay, and it appears to
20 me that the only way you're going to be able to do it,
21 that your TSO has to use these tools either on line or
22 off line, and we're not fussy about which, you know,
23 whether you do it on line or off line, but you need to
24 assure yourself and us that, indeed, you're meeting
25 your licensing basis. Okay. As simple as that.

1 Now, if you're not using any of the tools,
2 if your TSO is not using any of the tools, then tell
3 us how you're meeting, you know, -- you know, how do
4 you assure you have adequate and reliable off-site
5 power system?
6 So the questions are basically focused in
7 that area, and we can, you know, talk more about these
8 questions if need be.
9 And the third question talks about
10 operability determination for post trip, and that
11 would be slide number 18, please, and let's go to the
12 gist of the questions on 19 and 20. I'm sorry. Just
13 19. That has six subset questions.
14 Voltage inoperability triggers. In other
15 words, we want to know what triggers do you have in
16 terms of that you don't have adequate voltage in the
17 switchyard?
18 And it talks about double sequencing
19 operability. This is not the double contingency that
20 Jim was referring to.
21 Now, as I understand it, you may not be
22 licensed to double sequencing, you know, type of
23 scenario. It assumes that you have a trip of the
24 reactor and your off-site power is still there and
25 assumes that you have a LOCA at the same time, but if

1 you have a LOCA you have a unit trip.
2 And it assumes that you still have power.
3 You haven't lost the off-site power. So to meet
4 mitigate LOCA, you're going to have to sequence on all
5 the safety equipment that you need.
6 Now, the question is: what if you lose
7 power, delayed loss of off-site power? That you lose
8 off-site power some time into when you are sequencing
9 on the safety equipment.
10 And I think this issue has been discussed
11 with the industry, you know, over the years, and I
12 don't think you reached any conclusions on that as far
13 as I know, but we are asking that question: have you
14 thought about it? What if you lose off-site power
15 now? Are you now going to, you know -- you know, is
16 that diesel that comes on, is going to now block load
17 or is it going to -- or some other, you know, safety
18 equipment fails -- have you looked at in terms of
19 those type of scenarios?
20 And tell us, you know, what's the outcome
21 and if you, you know, declare that equipment to be
22 inoperable if that should happen?
23 Okay. So that's kind of a, you know,
24 "what if" scenario that you lose off-site power at
25 some time later than when the reactor trips.

1 And of course, in all of these questions,
2 we are asking, you know, training and procedures. Do
3 you have adequate procedures and training for your
4 operators? I think that's a very important one.
5 And the fourth question in that area is
6 tech specs require that plant's off-site system be
7 operable as part of the plan limiting condition of
8 operation. So if you are familiar, for those of you
9 that deal with tech specs, you will find that it has,
10 you know, allowable values. These days we are
11 changing from the actual trip values to allowable
12 values, and we are looking at or we are asking you,
13 you know, do you have any guidance in place that
14 alerts your operators in terms of the set point trip
15 values as well as on-site equipment, such as voltage
16 tap changing, you know, transformers or some of the
17 voltage control equipment that you are using within
18 the plant or within the switchyard that helps you
19 maintain that voltage or the operators are, you know,
20 familiar with it, trained in it, you know, in that
21 equipment. Okay?
22 And so those are the questions that we are
23 asking in the off-site area, in the four areas, and as
24 I said, the reason why we kind of made it into four
25 questions was to help you, you know, understand and

1 also to focus on the type of information that the
2 staff was looking for or is looking for. Okay?
3 Let's go to Slide 22 and 23. More onto
4 the risk area. Under (a)(4) you're required to
5 evaluate off-site power system or include it in your
6 risk evaluations.
7 The questions that deal in this area is
8 input into the risk assessment. During the
9 maintenance are you monitoring the grid? The question
10 came up about seasonal variation. I think according
11 to our maintenance rule experts, yeah, you're not
12 required to do it, but wouldn't it be nice to know
13 what you're doing and when do they occur. Are they in
14 the summer months, as we think it is, or are they in
15 the winter months?
16 You know, depending upon the geographical
17 area that you're in your seasonable variations that
18 impact the grid might be different. You might have a
19 winter peak rather than a summer peak.
20 So those are the questions that we, you
21 know, are asking in that area. In terms of the
22 seasonal variation, do they impact your loop
23 frequency? Okay?
24 And then also this goes back to the
25 communication between the TSO and the nuclear power

1 plant operators. If they find things, you know, that
2 are becoming stressed on the grid, how long does it
3 take for the TSO to inform you or do you make periodic
4 checks with the TSO to keep on top of it?
5 And you know, for us to think that, gee,
6 I'm just going to sit here and wait for the TSO to
7 tell me, that may not happen. So I think, you know,
8 we need a very smooth, very effective, you know,
9 communication type of agreements or protocols or
10 whatever you want to call them between the
11 transmission system operator and the nuclear power
12 plant operators.
13 And then there's the second question that
14 deals with -- it's how are the results of the
15 maintenance risk assessment included in the results of
16 the grid stability evaluations used in managing risk?
17 Okay, and this has nine subparts to it.
18 Again, you know, dealing with the maintenance and the
19 communication with the TSO.
20 Okay. Let's go to Slide 28 on station
21 blackout.
22 Now, for station blackout I mentioned
23 about, you know, how we arrive at the coping duration.
24 There's a very cumbersome process to go through to
25 come up at the coping duration. Now, the regulatory

1 guide that addresses station blackout is 1.155, and
2 the complement document or the industry guidance is
3 NUMARK; I believe now might be NEI 8700. I don't know
4 how they numbered it. But those were the two
5 documents that were used for implementing station
6 blackout rule.
7 And if you examined the Reg Guide 1.55,
8 Section 2 that talks about off-site power and the
9 NUMARK 8700, Section 4.3.2, those two sections or
10 those sections in the Reg. Guide and the NUMARK very
11 specifically talk about having procedures for
12 restoring off-site power and the use of nearby local
13 power sources.
14 The question we are asking in that area is
15 I believe that from our feedback from the TIs, that
16 either all or the majority of the plants have
17 procedures for restoring off-site power. What we did
18 not see is that the use of nearby power sources -- and
19 they are defined in the reg. guide as to what they
20 are, and also in the NUMARK it talks about local power
21 sources such as the generators or black star diesels
22 and so on, and it also talks about in the NUMARK that
23 you should coordinate all of this with the load
24 dispatchers.
25 Okay. In the old days we did not use this

1 fancy term about transmission system operator. The
2 transmission system operator was basically a load
3 dispatcher. The guy that controlled the transmission
4 system.
5 So now if you don't have the
6 communication, you know, agreement or protocols in
7 place with your transmission system operator, the
8 question that we want to know is how are you now going
9 to implement this feature of using the local power
10 sources. Have these arrangements been carried through
11 from the old system to the new system or they've kind
12 of just fell off the deck?
13 Okay. So we want to know, you know, where
14 are you, you know, for your specific plan. Have you
15 carried that, you know, feature across from the old
16 system to the new system, and based upon the answer,
17 you know, then we would evaluate it and see what we
18 need to do.
19 The other question that we are asking is
20 about the loop frequency or loss of off-site power due
21 to grid related events. In the station blackout, they
22 looked at loss of the off-site power due to many, you
23 know, in plant type of losses or losses due to the in-
24 plant type of equipment failures, loss from the
25 sweeter weather (phonetic), extremely sweeter weather

1 and so on, and also looked at the grid related losses.
2 Now, given that we've had some loops, and
3 again, that's a question for debate. I think you will
4 hear both sides saying, now, the industry is probably,
5 EPRI is probably going to say, well, you know, we
6 haven't had that many or haven't had any. Staff is
7 going to show you differently, I think.
8 But leave that aside. The question that
9 we want to know from our electrical area in terms of
10 implementing the station blackout rule, that if your
11 frequency has changed due to grid related loops, how
12 is your impact duration?
13 Okay, and I talked about that. What if
14 you go from four hours to eight hours? Okay. Now, it
15 depends on the answer, that if you're still four
16 hours, you have analysis that shows the plant is going
17 to be safe for four hours, but should you now go to
18 eight hours, your old analysis is no longer valid.
19 And we need to ask that question because,
20 you know, we can't sit here and get a warm feeling
21 that everything is going to be all right if, indeed,
22 you're coping duration has changed. Now, we can argue
23 whether, you know, what are grid related losses and so
24 on, and I think with some plants we've argued that
25 back and forth, but we need to ask you that question,

1 and it's a very serious question in the sense that
2 let's not fool ourselves. If, indeed, your coping
3 duration has changed, you no longer are meeting the
4 station blackout rule.
5 Okay. Because if you get to station
6 blackout as I kind of told you, you know, with one
7 diesel on the floor, the other one doesn't start and
8 you've lost off-site power; you are in station
9 blackout. Now, the worst thing is that if you don't
10 recover within the time period for which you are
11 licensed, you've got a very serious safety issue
12 because you're going to run out of battery; you're
13 going to run out of water. Okay? And you know,
14 you're going to have serious consequences.
15 I think with that, I'm kind of done.
16 MR. CAMERON: Okay.
17 MR. GILL: I don't know why my mouth is
18 drying up. Maybe I'm nervous, right?
19 MR. CAMERON: thanks, Paul. That was a
20 pretty comprehensive overview of the generic letter,
21 the regulatory requirements, the assumptions.
22 We have a few minutes for questions and
23 commentary. Keep in mind that all of the questions
24 are going to be addressed in detail by the panels, and
25 Paul is going to be here as a resource on that.

1 Perhaps questions, he went through the regulatory
2 requirements. Maybe questions on the regulatory
3 requirements or assumptions that the NRC is basing the
4 GL on might be appropriate at this point.
5 Let's go to Alex Marion. You're going to
6 use this? Okay, great.
7 MR. MARION: Alex Marion, NEI.
8 Point of clarification and a couple of
9 other comments. Mr. Gill, in your presentation you
10 talked about the off-site power characterization
11 that's used as part of the station blackout coping
12 analysis, and that's the P-1, the P-1 category, and if
13 I understood you correctly, you indicated it goes from
14 the very best to the very worst, and I'd like to
15 clarify that.
16 MR. GILL: Well, what I was saying was --
17 MR. MARION: The categorizations represent
18 the configurations of off-site power for the U.S.
19 plants.
20 MR. GILL: That's right.
21 MR. MARION: Not necessarily quantifying
22 good, bad, or indifferent.
23 MR. GILL: I was probably using -- just to
24 make my point, if I have three categories, P-1 to me
25 is the best. P-3 says if you're in P-3, you have the

1 worst off-site characterization of the off-site power
2 configuration to your plant.
3 So if you will indulge me, in my passion
4 I say that's the worst. Now, I'm not saying that in
5 a derogatory manner. I'm saying in a very relative
6 term, going from the very best to the very not so
7 best.
8 (Laughter.)
9 MR. GILL: If that's what you like. I
10 mean, you know, I'm about semantics here.
11 MR. MARION: Since this is being
12 transcribed, I want to make sure the record is clear.
13 MR. GILL: Sure, no.
14 MR. MARION: And they do represent the
15 off-site power configurations for plants who were
16 licensed by the NRC.
17 MR. GILL: That's correct. I'm not saying
18 that's not acceptable.
19 MR. MARION: Now, the methodology, the
20 methodology plays out a process where you're
21 penalized, if you will, for certain configurations.
22 That's part of the process.
23 MR. GILL: Right.
24 MR. MARION: And I respect your opinion.
25 You did make a couple of comments that some of the

1 information that's being requested is not required,
2 and I agree with that.
3 You also clearly in the generic letter,
4 the basis for requesting the information is to obtain
5 information to make a decision on the operating
6 license of a plant under the provisions of 50.54(f).
7 Just a comment, again, for the record.
8 Sine the subject of the questions are not required,
9 then how does 50.54(f) play out since they're clearly
10 not in the licensing basis of the plant? And that's
11 a subject we can talk about for hours, but I just want
12 to put that on the record.
13 Lastly, there's a new provision or a new
14 portion of the proposed generic letter that's
15 different than what was released for public comment,
16 and that deals with training. Given that that was
17 added and the public stakeholders did not have an
18 opportunity to comment, could someone explain the
19 rationale for not putting it out for comment or at
20 least seeking stakeholder comment on that particular
21 area?
22 MR. CAMERON: Do you want to address that
23 last point?
24 MR. GILL: Well, the last point in terms
25 of adding the training procedures and training, the

1 Commission issued an SRM, the same SRM that it asked
2 us to issue a generic letter, had a provision in
3 procedures and training. If I can be up front about
4 it, we kind of missed it, and then when we discovered
5 that it needed to be done, so we included that.
6 It was cleared with the Office of General
7 Counsel. They said we didn't have to go back out
8 again for re-comments, that we could include it in the
9 generic letter.
10 MR. CAMERON: Okay, and I guess the bottom
11 line here is, as you heard Mr. Sheron talk about
12 earlier, this is not meant to be a reopening of a
13 comment period, but anything that you say during the
14 next day and a half is going to be looked at by the
15 NRC staff. So I guess the most important thing is if
16 there are substantive issues related to the training
17 procedures, raise them during the next day and a half
18 so that the staff will have the benefit of your
19 comments.
20 In terms of the last point before that
21 that Mr. Marion raised in terms of the 50.54(f), Paul
22 or Brian? Brian.
23 MR. SHERON: Fifty, fifty-four (f), you
24 know, as you know, it allows the staff to request
25 information. I think the words are to determine if we

1 want to suspend, modify, or whatever your license.
2 Okay?
3 We use that as an opportunity to gather
4 information if we believe there is a safety concern
5 associated with principally compliance. We can use it
6 for two reasons.
7 One is we can gather information to
8 determine if we need to change our regulations. In
9 other words, if we are seeking information to
10 determine if our regulations are inadequate, you know,
11 we need to, for example, promulgate a new regulation
12 or in this case, we determined that we believed our
13 regulations were adequate and covered the situation
14 that we're dealing with, but it raised -- the
15 situation raised questions about whether we had
16 assurance that compliance was being achieved.
17 And you know, we use the generic letter.
18 Again, what's in the generic letter, what is
19 requested, as Alex said, it's not a requirement or
20 anything. What we're doing is we're saying that this
21 is what we think would be sufficient to demonstrate
22 compliance. We're trying to help the industry to some
23 extent. We're telling you what we would accept.
24 And if a licensee comes in and says, "Yes,
25 we're doing this. We have these protocols with our

1 TSO. You know, we take a look at risk or grid
2 reliability when we go into a maintenance outage or
3 whatever," you know, then we would probably find that
4 acceptable and say, "Yes, you know, we're satisfied
5 you're complying with the regulations."
6 Now, if you don't want to come in and say,
7 you know, I agree with the NRC and am doing all of
8 these things, then you want to know what you are
9 doing. Okay? You know what the underlying concern
10 is. So you need to tell us what provisions you've put
11 in place to help us provide that assurance.
12 We will evaluate that and, you know, I'll
13 be quite honest. You know, if we don't find it
14 acceptable, then we'll decide what we have to do,
15 whether it's a plant specific backfit or not.
16 You've got to remember a lot of times
17 people always say, "Well, why don't you just backfit?"
18 Well, we could do that, okay, if we had
19 perfect knowledge and we knew that every licensee was
20 definitely not complying with a regulation. But we
21 don't know that, and we'd like to give the industry
22 the benefit of the doubt, and that's why we go with
23 the generic letter, and that's why it requests
24 information that says we don't think you're complying
25 or we think there's a compliance issue here. We need

1 more information before we can make a decision. Okay?
2 We're not at that point where we can just
3 say everybody has to be backfit and do the following.
4 We want to give you an opportunity. If you have other
5 information that says, you know, "Well, look. I don't
6 have this specific protocol or whatever with my TSO,
7 but this is what I do have," we'll evaluate it, and if
8 it makes sense, then that's fine.
9 But that's the whole purpose of a generic
10 letter, okay, is we explain what our concern is, what
11 the safety concern is. We give you an opportunity to
12 either tell us what you are doing, why you don't think
13 it's a concern, or as I said, we try and be helpful
14 and say this is what the NRC will find acceptable, and
15 if you want to do it this way, then you know, you can
16 commit to it and, you know, we'll all move forward.
17 MR. CAMERON: Hey, thanks, Brian.
18 Alex, Brian put a finer point on the
19 50.54(f) issue. Do you have anything else that you
20 want to say on that before we move on?
21 MR. MARION: Alex Marion.
22 Our comments that were submitted on the
23 draft generic letter, I think, contain all of the
24 details.
25 MR. CAMERON: Thank you.

1 Dick.

2 MR. ROSENBLUM: Thank you.

3 Dick Rosenblum from Southern California

4 Edison again.

5 I get a little confused both when I read

6 the generic letter and when I listen to various people

7 from the NRC discuss this about what the NRC

8 expectation is concerning the interface between the

9 nuclear power plant and the grid operator,

10 transmission operator in this respect. Hypothetically

11 if the power plant were designed appropriately and

12 operated appropriately to GDCs and station blackout

13 rule, et cetera, et cetera, and if the grid operator

14 used whatever interface criteria were in an agreement

15 between the nuclear power plant operator and the grid

16 operator to notify the plant operator any time those

17 conditions weren't being met; so you've got a clear

18 interface requirement, all the criteria are adequately

19 assessed and known, the grid operator operates the

20 grid. Any time you are outside let me just say

21 acceptable operating space on the grid, they call the

22 nuclear power plant operator and let them know.

23 Is that acceptable, or do you have to have

24 that, which is sort of Question 1(a), and 1(b) which

25 says, "And, oh, by the way, periodically talk to your

1 grid operator above and beyond that," because that's
2 very unclear and it permeates this discussion.
3 If you have acceptable operating interface
4 requirements, is it okay for the grid operator to
5 operate and let you know when those are no longer
6 being fulfilled, or do you somehow have to do more
7 than that?
8 MR. CAMERON: Okay. Thank you, Dick.
9 And I think the question is very clear.
10 Paul, do you understand the question, Paul?
11 MR. GILL: No, I understand the question,
12 and again, I don't see where the confusion is coming
13 from. What we are asking is that, yeah, as I
14 explained, there is a licensing basis. There is a --
15 you know, for the off-site power system. Is the
16 transmission system being operated in the confines of
17 that analysis?
18 Now, if it is not, then the TSO needs to
19 tell the nuclear power plant operator that if I lose,
20 say, a nuclear unit or lose a transmission line or
21 whatever, then you're not going to have adequate
22 voltage. He needs to communicate that to the nuclear
23 power plant operator.
24 MR. CAMERON: And, Dick, let me make sure
25 you're on the record. No, don't worry about that, but

1 I guess the question you had is if there is an
2 existing protocol that will cover when the TSO has to
3 communicate, et cetera, et cetera, is that sufficient
4 or is there something over and above that that you
5 need to do?
6 And based on what you have heard from
7 Paul, is there still an ambiguity there?
8 MR. ROSENBLUM: Well, I fully understood
9 the answer, but it seems as I listen to the
10 discussions and as I read the generic letter to be
11 inconsistent with some of the assumptions underlying
12 some of the questions in the generic letter, and
13 that's why I thought that seminal issue needed to be
14 resolved.
15 If that interface criteria, assuming
16 everything is appropriate, and notifications across
17 that interface criteria are necessary and sufficient
18 and you need do no more than that, then the clarity
19 that that is necessary and sufficient is very
20 important to us.
21 MR. CAMERON: Okay, and I guess that one
22 of the objectives of the generic letter might be for
23 the NRC to determine whether that arrangement is
24 necessary and sufficient, and if it is necessary and
25 sufficient, is that the end of the question?

1 Paul, do you have anything?

2 MR. GILL: You know, again, as I said,

3 unless they just want to talk. I mean, the nuclear

4 power plant operator needs to know when that

5 transmission system, the basis for having reliable

6 off-site power is outside the bounds of that.

7 MR. CAMERON: Is some of the information

8 that's given to us in response to the generic letter

9 if the operator, the licensee, rather, said that we

10 think that our arrangement is going to provide us with

11 everything necessary and sufficient to address these

12 concerns, then that would be something that would be

13 useful to know.

14 Brian? Okay. Let's go to Mike, and I

15 forgot that Steve Alexander, our maintenance expert,

16 had one caveat that he wanted to add to Paul's

17 presentation, but let me go to Mike on this issue.

18 Mike.

19 MR. MAYFIELD: Mike Mayfield, Director of

20 the Division of Engineering at NRR, and this generic

21 letter is coming out of my division.

22 So at some point I'm the one that

23 everybody seems to be steamed at.

24 (Laughter.)

25 MR. MAYFIELD: I think as Jim Dyer opened

1 this up this morning, part of what we're willing to do
2 is see if there are areas we need to clarify in the
3 generic letter. This strikes me as one that we don't
4 want to get out today and give you an answer. It's a
5 fair question, and it's plainly something we need to
6 go back and be real clear on in the generic letter.
7 So that's the commitment you'll get, is
8 we'll go back and look at the way we're posing the
9 questions and the background information, and
10 hopefully we'll make that real clear as we go forward.
11 MR. CAMERON: Great. Thank you for that
12 comment, Dick, and leading to clarification that the
13 staff is going to take a look at.
14 Steve, did you want to add anything to
15 Paul's presentation on maintenance? Go ahead.
16 MR. ALEXANDER: Steve Alexander.
17 The new name for our reorganized branch is
18 PRA Operational Support and Maintenance in the
19 Division of Risk Assessment, and I had some input into
20 the generic letter in the maintenance rule area.
21 And just a couple of clarification.
22 People talk about simply taking risks equipment out of
23 service prior to maintenance. The maintenance rule,
24 Paragraph (a)(4), talks about maintenance activities,
25 and that's a little bit broader definition.

1 And so what we did is in the generic
2 letter we coined a term "grid risk sensitive
3 maintenance activities." So it's important to keep in
4 mind that those include three categories of things.
5 One is maintenance activities that could
6 cause or require a plant trip or a plant shutdown, and
7 to clarify a question we had earlier, you know, once
8 a plant trips for whatever reason, it doesn't have to
9 be for a design basis accident. You still have to
10 remove decay heat, and so the unit trip for whatever
11 reason is going to be affected by the availability of
12 off-site power.
13 And so that's one of our categories of
14 grid risk sensitive maintenance activities. So
15 that's, again, anything that could cause a plant trip
16 or could require a plant trip or plant shutdown.
17 The second is anything that might cause
18 loss of off-site power for no other reason, just
19 because it could cause a trip in breakers in the
20 switchyard. So switchyard maintenance might be an
21 example of something that could be grid risk
22 sensitive, because it may cause you to divorce from
23 short power, to use my old life here, and therefore,
24 affect the availability of power for safety buses.
25 And the third category of grid risk

1 sensitive maintenance activities that we talk about
2 are those that could affect the ability to cope with
3 a loss of off-site power or station blackout. So you
4 kind of are trying to maintain when we're thinking
5 about this the big picture of all three of those types
6 of maintenance activities that can affect maintenance
7 risk, which is what Paragraph (a)(4) requires you to
8 assess.
9 And even though it doesn't specifically
10 require formal agreements with the transmission system
11 operator, in fact, there's no documentation
12 requirements or procedural requirements whatsoever,
13 and also because it doesn't require things like RTCAs,
14 but what we want to know with respect to the
15 maintenance rule is because we believe that off-site
16 power availability, reliability, stability, all of
17 those things are an external condition that affects
18 plant risk, therefore it should be taken into account
19 in the assessment; we also think that in order to do
20 a meaningful grid reliability evaluation as part of
21 your (a)(4) risk assessment, you need to be able to
22 communicate with the TSO, and so we'd like to know is
23 that being done and how it's being done just to
24 provide some reasonable assurance and expectation of
25 consistent compliance.

1 Thank you.

2 MR. CAMERON: Thank you very much, Steve.

3 Let's take a couple more questions. We

4 will be going back through these issues. Let's take

5 a couple more because we're headed for a break time,

6 and let's go to this gentleman right here. Yes, sir.

7 MR. THORSON: Yeah, James Thorson, Detroit

8 Edison.

9 I had a very specific, I guess, question

10 and possibly a comment with respect to the RTCA

11 programs. The generic letter in question, 2(f), asks

12 about nuclear power plant actions with respect to when

13 the TSO might notify the nuclear power plant on the

14 loss of their RTCA capability.

15 And I guess my question is: what was it

16 that caused the NRC to try and put the onus on the

17 nuclear power plant to produce an operability

18 determination upon the loss of an RTCA, which will be

19 very difficult for the nuclear power plant to do

20 without the same tools as a TSO? Why did it end up in

21 that category rather than perhaps over in the risk

22 area, which may have been a little, at least in my

23 opinion, you could recognize perhaps that you were in

24 a state of increased risk as opposed to a state of

25 needing to determine operabilities?

1 I was just curious what caused the balance
2 to shift towards operability as opposed to a state of
3 increased risk.
4 MR. CAMERON: Paul.
5 MR. GILL: I guess the way I would answer
6 that question, what it's asking is that if your TSO
7 does not or loses the RTCA program, for example, he
8 has no way of now looking at the grid or transmission
9 system to see the status in terms of meeting the NPP
10 requirements.
11 Remember, I talk about the licensing
12 basis. For example, if he doesn't have the RTCA, you
13 know, for a unit trip, for example or critical
14 transmission line, he has no way of knowing that
15 you're going to lose off-site power at the nuclear
16 power plant.
17 So the question that we are asking is that
18 if he does not have the RTCA, therefore you don't have
19 the information that if the reactor trips you're going
20 to have adequate power in the switchyard or adequate
21 voltage. Let me put it that way.
22 Now, if you don't have adequate voltage,
23 then the question of operability comes in. For
24 example, if the unit trips or reactor trips, your
25 voltage goes down below the degraded grid voltage set

1 point. So you're going to lose off-site power to the
2 safety buses.
3 So now the question is one could pose a
4 question, is your off-site system operable under those
5 circumstances or not?
6 MR. THORSON: (Speaking from an unmiked
7 location.)
8 MR. GILL: No, but your TSO should be able
9 to communicate to you and say, "I don't have the RTCA
10 program available to me," to tell you that your system
11 is going to be -- everything is fine. So as a nuclear
12 power plant operator, you have two choices. You could
13 just sit there and do nothing or declare off site
14 unavailable, for example.
15 MR. CAMERON: Okay. It sounds like this
16 is --
17 MR. GILL: You know, you --
18 MR. CAMERON: It sounds like this question
19 is raising a lot of concerns, and I'm going to put
20 this question in the parking lot right now, and we'll
21 come back and explore it because it seems like it's a
22 big issue. Okay?
23 MR. GILL: All the question is posing is
24 it says when you get such a notification, okay, do you
25 conduct an operability evaluation or not.

1 MR. CAMERON: Okay. James, we're not
2 getting you on the record here, and I am going to put
3 this in the parking lot because it sounds like there's
4 several of your colleagues who also have a concern
5 her, and we are going to be -- I'll check with the
6 staff in terms of when the best time to discuss that
7 is.
8 So let's take two more comments now and
9 we're going to take a break, and we're going to get to
10 everybody, but it just won't be right now.
11 Yes, sir.
12 MR. MOIENI: Parviz Moieni from the PRA
13 Group. Oh, sorry. I thought I was speaking too loud.
14 Parviz Moieni from the San Onofre PRA Group.
15 I'm glad Steve Alexander is here so he
16 basically will have an answer for me.
17 When you look at the generic letter, the
18 grid reliability evaluation has been mentioned a lot,
19 and of course, RCTAs have been mentioned a lot. Grid
20 reliability relation, I hope the staff basically
21 realizes what that means, and it basically clarifies
22 the term very well for the PRA engineers because, as
23 we know, when we do the PRA evaluations or risk
24 evaluations for (a)(4), we go back to our PRA, and we
25 have a safety monitor at the plant, real time safety

monitor. So we use that.

The attributes for grid reliability right now for our PRA and I believe for most of the PRAs is loss of off-site power frequency and duration, which basically translates into recovery.

How do we basically translate the grid conditions to the grid reliability? This is really important, especially when the two attributes are lot frequency and recovery or duration. It's not an easy task, especially when you go outside the switchyard. When you go to the grid, this becomes almost an open ended problem.

Then the other thing is that I heard that RCTAs reliability of the grid. How do you relate the RCTA results to grid reliability? Let's say I want to do a risk evaluation and I call my grid operator or the grid operator, and he gives me some ideas. How do I translate it to my low frequency and duration?

So are there any reports? Are there any published data that shows me any correlation between RCTAs even on a generic basis, not plant specific base, to grid reliability?

Back in 1997 -- this is just for information -- we had to do the PRA group with the engineering, had to do a blanket start study to show

1 that when we sell our fossil plants, the blanket start
2 capability or reliability is pretty high.
3 So we had to do a study basically for
4 consideration San Onofre blanket start units, San
5 Diego Gas & Electric, even consider the Hoover Dam for
6 some other power sources.
7 Believe it or not, it took us about three
8 months, and a group of like ten engineers, some from
9 the grid operators back then or grid control centers,
10 to come up with a reliability of the blanket start
11 because we went outside the switchyard. We considered
12 the grid, other sources.
13 So it's not an easy task. I don't think
14 when we want to do basically a weekly control
15 evaluation or equipment control evaluation to consider
16 the grid reliability in the sense of grid reliability.
17 So it's very important. The generic letter, I think,
18 redefines what we mean by grid reliability, how we
19 translate or correlate the grid reliability, grid
20 conditions to grid reliability.
21 Right now if you ask us, we say, yeah, we
22 basically have some conditions that raises the loop
23 frequency and duration for certain conditions, but is
24 it a real time? No, it's not a real time because we
25 don't know how to do it.

1 So I hope that this would be basically
2 clarified. Otherwise I think the answers would be yes
3 or no. So I don't think we would basically give very
4 exact answers because we don't know. At least I don't
5 know how to do it.
6 Thank you.
7 MR. CAMERON: Okay. Did the NRC staff
8 note that request for a clarification on grid
9 reliability?
10 And, Steve, if you're going to say
11 something on that, I guess try to make it quick.
12 MR. ALEXANDER: I can't address his
13 question with respect to the entire generic letter,
14 but with respect to the maintenance rule area, those
15 of you who are familiar with Paragraph (a)(4) of the
16 maintenance rule realize and are also familiar with
17 the way that we have inspected and enforce those area
18 of the last five years we don't expect that every
19 external condition or event be quantitatively analyzed
20 and evaluated. We recognize that it is difficult, in
21 some cases impossible for people to do quantitative
22 analysis of various external conditions, including
23 grid reliability or availability or conditions.
24 And so what we expect as far as
25 maintenance rule compliance is that you recognize that

1 under some conditions there may be increased plant
2 risk. If you can't quantify that, it's going to
3 translate, as you said, basically into additional risk
4 management action, some of which involved making
5 decisions on what kind of maintenance you're going to
6 do.
7 So to comply with the maintenance rule,
8 you can do a qualitative analysis of the risk,
9 qualitative risk assessment and decide if the way that
10 you're doing the maintenance things may need to be
11 postponed, rescheduled, done a different way,
12 contingency plans or compensatory measures may need to
13 be taken, and in fact, with all kinds of things that
14 have to be analyzed qualitatively in terms of risk,
15 the risk assessment amounts to a recognition that the
16 risk is increased and then taking some kinds of
17 actions that can reduce overall plant risk or that
18 target specific areas that need to be looked at
19 because of the nature of the external conditions that
20 are causing the increased risk.
21 So it can be done qualitatively in a
22 blended fashion.
23 MR. CAMERON: Okay. Thank you.
24 And, Mike, again in keeping with perhaps
25 necessary clarifications in the letter. Okay. Good.

1 I think that we probably should take a
2 break now and see if we can get back on schedule. I'm
3 putting Mr. Thorson's issue, which is RTCA capability,
4 does that transfer into inoperability or increased
5 risk; I'll put that in the parking lot, and we will
6 come back and discuss that.
7 And I think right now we're slated for
8 about 15 minutes on the break. We do have more hard
9 copies of the slides coming. There is a USB one of
10 those little gadgets for those of you who want to plug
11 it into your laptop and download it, but we will have
12 hard copies for you.
13 Restrooms are back in that corner.
14 There's coffee on the lobby level. I have about 17 to
15 11. Why don't we come back in about 17 minutes and
16 we'll get started.
17 (Whereupon, the foregoing matter went off
18 the record at 10:42 a.m. and went back on
19 the record at 11:00 a.m.)
20 MR. CAMERON: Okay. Just a couple of
21 announcements before we get started with what we're
22 calling the risk insights panel which are going to
23 cover material related to GL Questions 5, 7 and 8.
24 One is Mr. Thorson raised the issue of RCTA capability
25 and whether that corresponds to inoperability or

1 increased risk, and excuse my ignorance in
2 characterizing that, but I think you all know what the
3 issue is.
4 We're going to -- it seems like that fits
5 into the discussion of not this panel but the next
6 panel. So we're going to try to get to it there, and
7 we're going to go to Mr. Tom Koshy of the NRC staff to
8 sort of address that for us, and then we'll get into
9 a discussion.
10 Another overarching issue that we need to
11 get to at some point that I've heard people express a
12 concern about is the whole idea of providing
13 information to the NRC, the licensee providing
14 information that really is in the province of another
15 organization over whom the licensee has no control
16 over.
17 So that seems to be something that runs
18 through these discussions.
19 We're going to go to the next panel and we
20 have Dale Rasmuson from the NRC staff Office of
21 Nuclear Regulatory Research; Mr. Bill Raughley from,
22 again, NRC Office of Nuclear Regulatory Research; and
23 then we have Mr. Gary Vine from EPRI, the Electric
24 Power Research Institute.
25 So are we going to start with Dale or

1 Bill? Dale, then Bill, then Gary, then we'll give
2 them an opportunity to ask each other a question or
3 so, and then we're going to just go to you.
4 There's supposed to be a lunch break in
5 the middle of this panel, and we'll just see how the
6 time is going.
7 So okay. Let's turn it over to Dale.
8 MR. RASMUSON: Thank you very much.
9 I'm Dale Rasmuson from the Office of
10 Nuclear Regulatory Research, and as you know, NRC
11 recently finished a detailed update of station
12 blackout risk in terms of core damage frequency. The
13 report has been published as NUREG CR 6890, and it's
14 currently in printing and will be issued soon.
15 Next slide or this slide. That's the one
16 I want.
17 Okay. Station blackout risk measured in
18 core damage frequency is highly dependent on four
19 factors. They are loss of off-site power frequency,
20 loop duration, emergency diesel generator reliability,
21 and plant specific coping features such as battery
22 depletion time, turbine driven pump performance,
23 alternate on-site AC power sources, and reactor
24 coolant pump seal design.
25 These four elements are included in the

models, the standardized plant analysis risk models that were used in our analysis.

Next slide, please.

In our next few slides, I will summarize some insights from our recent study and then Bill will discuss insights he has gleaned from his analysis of some NERC data.

Next slide.

We first began with a review of the definition of loss of off-site power event and station blackout event. Note that these definitions are plant based or, if you want to use units, I'm referring to plant. We've used that to refer to a single unit, opposed to site based or recent based, and they're independent of the cause of the event.

Loop events were classified as plant status, critical or shutdown, and also as to the type of the event, plant centered, switchyard centered, grid related or weather related, following the protocol set up in NUREG 1032 and NUREG CR-5496.

Next slide, please.

This slide compares loop frequencies for two periods, 1986 through 1996 and 1997 through 2004, and these periods were defined in NUREG CR-1784, and this is showing the types of events and the

1 operational status.

2 For critical operation, plant centered and

3 switchyard centered frequencies have decreased, but

4 the grid related frequency has increased. The weather

5 related frequency remains about the same, and may I

6 say that for the -- there was only one shutdown or one

7 plant centered event for the latter period, 1997

8 through 2004.

9 For shutdown operation the switchyard

10 frequency has decreased and grid related frequency has

11 increased, but is not dominant compared with the

12 results for critical operation. Notice the difference

13 in the Y scales between the two graphs. The overall

14 shutdown frequency is approximately five times the

15 overall frequency for shutdown operation.

16 Next slide, please.

17 In this slide we compare seasonal

18 variation in loop frequency. The summer period is

19 defined as May through September, with the non-summer

20 period being the other seven months. For critical

21 operation, all four category frequencies are higher

22 during the summer period. In particular, the

23 switchyard centered and grid related frequencies are

24 much higher during the summer period.

25 For shutdown operation, the frequencies

1 for most categories are about the same. However, the
2 grid related frequency is greater during the summer,
3 but again, it's not dominant compared with critical
4 operation.
5 Next slide, please.
6 This slide shows a comparison of critical
7 looped events by months within the two time periods.
8 In the first graph we notice that the events occur
9 about equally across the months, 1986 through 1996.
10 And the dark ones, the blue ones are the summer
11 period. The lighter ones are the non-summer.
12 The second graph shows that the vast
13 majority of the events occurred during the summer
14 period during 1997 through 2004. The different summer
15 versus winter is highly statistically significant,
16 even with the August 14 2003 events removed and if we,
17 in addition, remove the Palo Verde events, the three
18 vents that occurred in '04.
19 Next slide, please.
20 This slide shows the number of switchyard
21 centered and grid related events for critical
22 operation and shutdown operation for the summer and
23 non-summer periods. The number of critical operations
24 switchyard centered events has decreased, but the
25 majority occurred during the summer period for 1997 to

2004. For the grid related events, most occurred during critical operation, and all occurred during the summer period.

This slide shows the annual loss of off-site power frequency for critical operation from 1996 to 2004. There is a decreasing trend from '86 through '96. The trend is essentially flat from '97 to '02. The decrease in the number of loop events is due to a decrease in plant centered and switchyard centered events beginning in the mid-1990s.

Only one plant centered loop event occurred during the period 1997 to 2004. Note that the number of critical looped events in 2003 and '04 is much higher than in previous years. For 2003 there were 12 loop events and for '04 there were five loop events.

Note that there were only, well, zero events in '05, you know, for a critical operation, and two for shutdown operation.

Next slide, please.

This slide shows the trend in annual average duration for loop events. The trend is increasing for the period '87 through '96, and the trend for loop duration for '97 to '03 is essentially flat.

1 Average durations have been increasing, in
2 part, because of the number of shorter duration events
3 has been decreasing, while the number of longer
4 duration events has remained about constant.
5 Next slide.
6 This slide shows the results of the
7 station blackout evaluation together with two results
8 from sensitivity studies. The industry mean, median,
9 and the max and minimum -- these are point
10 estimates -- are being shown, and that shows the range
11 for all the plants. So that represents 103 values in
12 those ranges there.
13 The industry annual mean SBO risk is in
14 the mid ten to the minus six range based on updated
15 loop frequencies, including '97 to '04 and updated
16 component data from mainly '98 to '02. Know that if
17 only the '03 and '04 data are used to determine the
18 loop frequency, the SBO risk would increase by
19 approximately a factor of three over the baseline
20 case. This is not shown in the figure.
21 The two sensitivity study show an
22 increased loop frequency during summer and decreased
23 loop frequency during the non-summer, and you can see
24 that there is an increase in the loop frequency for
25 the summer event, which is based on an increase in the

1 frequency of the loss of off-site power frequency.
2 I will now turn the time over to Bill.
3 MR. RAUGHLEY: FERC Order 888 was issued
4 in April 1996 and require that generators have open
5 access to the electric power transmission system.
6 Open access transmission generally results in more
7 power transactions and consequently more power train
8 transfers that change the power flows.
9 Increased power flows on the transmission
10 system have the potential to lower the nuclear power
11 plant off-site voltage to a level of impact.
12 Regardless of the restructuring status or
13 participation in the power market, all states and all
14 MPPs are exposed to the design and operating changes
15 associated with revised power flows attributable to
16 open access transmission. The case in point is the
17 1999 Callaway event. In this event the reactor
18 tripped from a problem in the heater drain system. At
19 the same time heavy power flows from interregional
20 transactions in the power market depressed switchyard
21 and safety bus voltages below that required for 12
22 hours.
23 This event prompted an IN and subsequent
24 RES interest in NERC transmission operating data that
25 I'll discuss later.

1 The next bullet, the U.S.-Canadian August
2 14th blackout task force report states that with the
3 absence of major transmission projects in the past ten
4 to 15 years, utilities have increased the utilization
5 of existing transmission facilities to meet increasing
6 demand without adding major equipment.
7 The task force report goes on to state
8 that the systems being operated closer to the edge of
9 reliability than it was a few years ago, and if
10 nothing else changed, we'll see more widespread
11 events.
12 In 2004, we had the West Wing event that
13 involved the simultaneous trip of three Palo Verde
14 units along with three loops.
15 As I've mentioned already, experience has
16 shown grid initiator reactor trips and loops impact
17 nuclear plant operation, and I've listed a few
18 examples here.
19 They also discussed the loops. Similar to
20 the loops, many of the recent reactor trips initiated
21 in the nuclear plant switchyard, the transmission
22 network or were widespread grid event.
23 At the March 2005 regulatory information
24 conference, Mr. Dyer who first spoke stated that in
25 2003 there were 23 reactor scrams of nuclear power

1 plants associated with grid problems, eight of which
2 were the blackout, and in 2004 there were 15 scrams
3 associated with group problems.
4 And as the last point, during the blackout
5 everything went as planned. There were no safety
6 problems, and the plants performed as expected, but
7 there were some event anomalies, I think, that
8 highlight some of the concerns that were expressed.
9 During this blackout, one of the licensees
10 was testing his EDG to the grid for its monthly
11 surveillance. The operator tripped the EDG and it
12 realigned to the safety bus, but it shows one of the
13 concerns about the risks for maintenance activities
14 with reactor power. In this case you'd lose both the
15 loop and the diesel from a single initiator, and in
16 this case if you carry that thought forward through
17 the single failure criteria, if another diesel, then
18 you'd be in a station blackout, and that's one way to
19 get to a station blackout.
20 Had the transmission operator understood
21 the importance of a diesel or the nuclear power plant,
22 the operator, the condition of the grid that day, this
23 activity may have been delayed or stopped to avoid the
24 risk of exposure.
25 Next slide.

1 What I've shown, this slide relates
2 directly to Paul's point about the last paragraph in
3 GD-17 where the licensees need to take provisions with
4 regard to the probability of a reactor trip given a
5 loop.
6 And this slide shows increases and
7 seasonal variations in that probability, and it is
8 sometimes referred to as a consequential loop. On the
9 left are the results of a study that was finished
10 before the August the 14th blackout, and on the left
11 are the results of the L study. On both studies you
12 can see that the annual frequency is doubled, and then
13 the summer frequency is approximately doubled against.
14 In these events, the reactor trips for
15 whatever reason, typically resulting in a loss of
16 generation in addition to a relatively large load from
17 the transfer of the NPP house loads, nuclear power
18 plant, house loads from auxiliary power to off-site
19 power. About 90 percent of the plants are designed
20 such that this happens.
21 This results in a voltage depression that
22 lasts a few seconds until the grid makes up the
23 difference. During an accident there would be an
24 additional load and voltage drop from the starting of
25 a safety load.

1 In either case if the voltage dropped low
2 enough, they operate at the greater voltage relays,
3 which operate or which automatically start the EDGs.
4 Reactor trips of random tests of the
5 capacity and capability of the grid in the events that
6 are driving the numbers here, the capability of
7 transmission system to supply power was affected by
8 transmission and non-safety nuclear power plant
9 equipment. In one case the plant owned transmission
10 load tap changer had been inoperable for 11 months,
11 and the plan grid operator response following the
12 reactor trip was ineffective.
13 In another case, the transmission system
14 owned both its regulator, had been wired incorrectly,
15 and the licensee reported that heavy power demand and
16 transmission outages contributed to the voltage
17 suppression.
18 In another case, a switchyard circuit
19 breaker, the generator circuit breaker, which is in
20 the switchyard, faulted, failed to open, and it
21 resulted in a second fault that caused the loss of
22 off-site power.
23 The grid is being operated in a condition
24 for whatever reason such that a reactor trip will
25 result in the loop than the probability of a loop for

1 that period of time is significantly above the numbers
2 on this slide and in Dale's presentation.
3 The entity that knows whether or not the
4 reactor trip or unit trip or reactor trip will result
5 in a loop relies on input from the transmission
6 entity.
7 What I also showed in the NUREG 1784 is I
8 pointed out that the typical risk analysis is to
9 consider a reactor trip in the loop to be independent
10 events. That is, the probability of a loop
11 initiating event is not impacted by the trip. As
12 shown in this NUREG, parsing out the consequential
13 loops from the typical loop fault tree in the
14 assessment of risk for maintenance and tests provides
15 for a way to do sensitivity analysis to evaluate the
16 impact of combinations of degraded grid EDG
17 unavailability, summertime probabilities and the
18 remaining loop frequencies.
19 As shown in this NUREG, these risks may be
20 made partially or fully offset the risk reduction from
21 SBO implementation.
22 Next slide.
23 And that might help to answer some of
24 Parviz's questions that he asked at the end of the
25 last presentation.

1 What we did here is after the August
2 blackout, we were tasked to obtain and analyze grid
3 data to assess the grid reliability so as to identify
4 changes, emerging trends that may be precursors to
5 impacts on NPP operation and risk. The nexus between
6 the grid and the NPP, or I keep calling NPP nuclear
7 power plant, is that the nuclear power plant is
8 connected to the grid as the generators of load and
9 subject to the same condition.
10 What I'm going to show in the next few
11 slides is an assessment of grid reliability based on
12 performance trends developed from their NERC
13 definitions of grid reliability. These are the only
14 definitions of grid reliability I could find, and this
15 includes the 600 grid disturbance events from their
16 database. It's the disturbance analysis database,
17 which is on their Website, and approximately 8,000
18 transmission load relief requests from '97 through
19 2005.
20 We used the data to provide reliability
21 measures to gauge the recent changes in grid
22 operation. The work benefitted from the guidance and
23 peer review by several NERC members.
24 What I did basically was bend the NERC
25 events according to their definitions. Examples of

adequacy events -- well, first off, NERC obtains a subset of events reported to the Department of Energy that are required by one of the CFRs, and they're really looking at the big stuff. Examples of adequacy events are areas wide voltage reductions, more than three percent. Examples of operating reliability events are losses of more than 50,000 customers for an hour, the loss of 300 megawatts of load for more than 15 minutes or load shedding of more than 100 megawatts under emergency conditions.

And there's a bunch of other criteria which is on the NERC Web page. All of the adequacy and operating liability events were blackouts, not to be confused with the NRC station blackout. About 15 percent of the NERC events only affected the distribution system, and the rest involved a transmission generator system. So what we're looking at is predominantly the performance of the transmission system.

The data contained some nuclear planned events. Basically about once every five years one of these impacts a nuclear power plant.

Next slide.

In this slide the adequacy trend is on the left and the operating reliability on the right. The

1 year-to-year days vary cyclic just like the loop data.
2 I had 20 years of the data and divide it into five-
3 year intervals on the horizontal axis and the number
4 of events on the vertical axis.
5 For the operating reliability, I came up
6 with the number of weather events in yellow and the
7 non-weather events in red. The NERC data clearly
8 indicates decreases in grid reliability.
9 As another observation, there's enough
10 change that the data since 1997 may be more
11 representative of grid operation than before.
12 On the left, improvements in adequacy of
13 the generation supply over the 15 years prior to 1999
14 have been offset by the declining group performance
15 from '99 through 2003. On the right, the operating
16 the liability was less from '99 to 2003 than it was
17 for the preceding 15 years for both weather and non-
18 weather events.
19 Next slide, please.
20 This slides is a subsort of the operating
21 reliability data. On the left are the larger events,
22 those involving a load loss of more than 800 megawatts
23 and the outage was around 750, 760 megawatts, and I
24 rounded it up to 800.
25 On the right are the events where it took

1 more than four hours to recover power to most
2 customers.
3 The figures show that since 1999, the
4 bigger blackouts are getting bigger, and of longer
5 duration the blackouts that occurred before '99.
6 I've got tons of sorts of this information
7 and some of them that the parallel Dale's data are
8 that since '99 the median size and median duration of
9 blackouts have increased.
10 Thus it appears that pushing the
11 transmission harder has diminished the grid's
12 capability to withstand contingencies when not
13 operated within reliability limits. It appears that
14 the U.S.-Canadian blackout task force assessment was
15 correct.
16 We would expect the implementation of
17 enforcement of reliability standards would improve the
18 situation and only time will tell. It's going to take
19 four or five years at least to change the reliability
20 trends that we're looking at on either the nuclear
21 plant side or the grid side.
22 Next slide.
23 This is the sort of NERC disturbance data
24 by months similar to Dale's sort by month. In this
25 slide I measured, and it's from 1997 and 1993.

1 Clearly, there's seasonal variation in the NERC
2 disturbances which increased sharply and peak in the
3 May-December time frame.
4 As you can see, you must be prepared for
5 a loop all the year, but what we're trying to
6 communicate here is that the things are changed enough
7 in the summer that you need to use different numbers
8 for your summertime risk assessment.
9 Next slide, please.
10 This slide was taken from the NERC long-
11 term reliability assessment. You heard earlier Mr.
12 Dyer or Mr. Sheron say that there was some indication
13 that in some areas there's a depression of or lack of
14 a reserve.
15 This slide deals with the capacity margin,
16 which is what's left over after you take the connected
17 load less planned/unplanned outages, less your reserve
18 requirement so that this is what's left over.
19 Now, what NERC is that they do a ten-year
20 forward looking assessment and the executive summary
21 of the current assessment which looks out to 2014
22 states resource adequacy is dependent on new
23 generation projects and the transmission system will
24 be operated at or near limits more frequently and that
25 the fuel supply in most regions are adequate.

1 These assessments examine, among other
2 things, the seasonable variation in the load and
3 capacity margins. Other information in the NERC
4 assessment shows the load growth of approximately two
5 to three percent per year and a decline in new
6 generation projects.
7 This will lead to the decrease in capacity
8 margins which are projected in the NERC slide here.
9 In this figure NERC compared a series of four ten-year
10 capacity margins for the summer operation of U.S., and
11 on the top you're starting with 2002, and as time goes
12 on, as you proceed from top to bottom, it's 2002,
13 2003, 2004, 2005.
14 So for 2005 in comparison to 2004 -- I'm
15 sorry -- the capacity margin for 2006 is about 15
16 percent less than the last projection, and decreases
17 to nine percent.
18 The curve shows the capacity margins are
19 shrinking with time. With less margin the grid will
20 be less robust and have less give to it.
21 The NERC regions have input to these
22 assessments and typically evaluate the information,
23 and if you pull that thread, if you go from the NERC
24 assessments to the ISO assessments, that that's where
25 you can get into where some of the ISOs are showing an

1 erosion of reserve requirements in the 2008-9 time
2 frame.
3 And likewise these NERC assessments, I
4 think, are very insightful. If you keep pulling these
5 threads, things seem to go the way they say.
6 As a result of the Callaway event, RES
7 took interest in the NERC transmission load relief
8 request logs and trends that are available on the
9 Website. Anticipating transmission line congestion
10 for more power transactions in the power market,
11 they're created the system of procedures and logs to
12 manage the congestion in eastern interconnection.
13 The reliability coordinators in the
14 transmission operation monitors the transmission line
15 limits. As predetermined limits are approached. The
16 reliability coordinator issues a TLR Level 1 to Level
17 5. Level 1 is an alert. Two to five require actions
18 such as backing out of a transaction or reconfiguring
19 some portion of the system.
20 The TLRs come from approaching the limits
21 as a result of power transactions. We've used the
22 info here to once again show the seasonal variations.
23 In addition, the chart shows the TLR data has become
24 more -- the system has become increasingly congested
25 from '99 to 2005. So if you start, the bottom line is

1 '97, '98, '99, and you work your way up to 2005. So
2 as deregulations kicked in and the power transactions
3 have increased, just a lot more activity.
4 And then I've done other sorts of this
5 data to show that there's a concentration of problems
6 at some flow gates and at some times in here. So that
7 I've indicated some bottlenecks or problem areas.
8 Next slide.
9 In this slide what I did was a log-log
10 plot of both the NERC data on the top and the NRC
11 Dale's loop data on the bottom. The durations, the
12 actual recovery times for the nuclear plant data, and
13 the restoration times reported in the NERC data, and
14 the blackout data, the nuclear plant blackout data is
15 up in the -- near the curve and goes down to the --
16 much before the 1,000 minute drop-off.
17 The NERC data, they have eight or nine
18 points reported from the different regions, but that
19 falls up in the knee of the curve also, but the point
20 here is that the August 14th blackout event is not an
21 outlier on either curve.
22 Note also on the curve if you look at the
23 grid events are longer than the nuclear plant events,
24 but it goes to show that the nuclear plants could be
25 exposed to events longer than those that they're

1 experiencing.

2 The events on the bottom of the NERC chart

3 are largely from ice storms where several transmission

4 towers were toppled at the same time. The risk here

5 comes from the fact that as the event gets longer, the

6 diesel reliability drops off. So if you plug in some

7 of the longer event numbers, you get much lower diesel

8 reliabilities than you would from typical nuclear

9 plant event.

10 The other thing that's happened here is

11 that most of the recent events are at or below the

12 knee of the curve and the events before 1996 are up

13 above, and most of them before 1996 were plant

14 centered. So what has happened is the plants have

15 corrected their problems. There has been a

16 disappearance of plant centered events as shown on

17 Dale's slide, and what that has left is a lot of

18 switchyard transmission system and grid events, so to

19 speak, and the recovery times of those are longer. So

20 that I think that explains the increase in the loop

21 duration.

22 But nonetheless, the numbers are the

23 numbers, and that's what you've got to use in the

24 analysis.

25 On the last two slides here, I've

1 summarized what Dale and I have told you, and our
2 bottom line is that we think the overall data and
3 experience support the generic letter. There's a lot
4 of offsetting variables going on here, and looking at
5 them all at the same time, the overall loop frequency
6 of the looped events have been declining since '88,
7 '86, but there was an upturn in 2003-2004. The grid
8 center loops are up significantly in recent years.
9 The average loop duration has increased significantly
10 since '86.
11 In recent years, almost all of the loop
12 events have occurred in the summer, May to September,
13 and that's where NRR is getting their seasonal
14 variation conclusion from.
15 And then the last slide, recent events
16 have raised questions about the likelihood of a loop
17 caused by reactor scrams. The seasonal variations in
18 loop fence and grid reliability raises questions about
19 maintenance of EDGs or SBO coping features during
20 summer months or during times of grid distress.
21 The fact that there's change going on adds
22 uncertainty about the future. You've got a moving
23 target here we're trying to hit, and the point of all
24 this loop stuff that I went over from NERC is that
25 there's a lot of loop precursors, but as a NERC grid

disturbance have risen significantly in recent years.

And then I also wanted to mention that SECY 050192 was recently issued by Research, and that's the status of the accident sequence precursor program and the standardized risk models, and it shows a statistically significant increasing trend in accident precursors involving a loop from '93 to 2004.

In the ASP events, the accident sequence precursor events are those events which have occurred where the condition of core damage probability is more than ten to the minus six, more than one in a million. When they reach ten to the minus five, that triggers more investigation by the NRC, and ten to the minus four and so on. We reach higher and higher level of interest in response from the NRC.

Gary.

MR. VINE: Hi. I'm Gary Vine from EPRI.

Next slide, please.

All right. We've been working with both NRC and with the industry for over 20 years on grid and diesel liability data. This goes back to the early to mid-1980s when the station blackout rule was taking shape and we were looking at the data. We found in those early days that there was a rather huge divergence between our analysis of the data and NRC's

1 analysis of the data, but those differences have been
2 largely reconciled over the years.
3 What was happening in the early years is
4 that both industry and NRC were relying heavily on LER
5 information for assessing the frequency and duration
6 of either diesel events or grid events, and it turns
7 out that a lot of that data was not very useful.
8 We ended up having to go talk to
9 individual plants and find out exactly what happened
10 in each of these events, and we determined in many
11 cases, for example, that maybe the grid had been
12 declared inoperable for a period of two days when it
13 was available within an hour or two, but it was not --
14 the plant was not put back on the grid until we were
15 really confident that it was a stable situation, nd we
16 would continue to operate off the diesels, and of
17 course, that would skew the data tremendously toward
18 a longer even than was really deserved in the data
19 analysis.
20 There were similar cases where there were
21 back-up or alternate AC power supplies available off
22 site or on site that weren't reflected in the LER. We
23 would learn about those things as we investigated the
24 event in more detail.
25 As we began looking at the data much more

1 comprehensively, NRC joined us and then through the
2 '90s and into this decade we usually found that the
3 raw data differences between our analysis of these
4 events and the NRC's event, pretty minimal. We've
5 been pretty close on the raw data since those early
6 years.
7 We've published a number of reports. We
8 continued in this analysis of both grid and diesel
9 reliability since the station blackout rule and
10 continue to do so. We've had very good cooperation
11 with NRC Research, which we have an MOU with and we've
12 done a lot of work together in this and other areas.
13 But there has been some divergence in our
14 analysis of the event since the August 14th event, and
15 perhaps a little bit earlier than that as well as we
16 began looking at grid centered events a little
17 differently.
18 Again, not a huge divergence in the raw
19 data, but significant divergence in interpretation of
20 the data. It's important to recognize just for
21 perspective that the goals of the station blackout
22 rule have been met or exceeded, and I'll say a little
23 bit more about that later, and also that the industry,
24 I think, even though the grid situation that we all
25 face due to deregulation and technology changes and

1 everything else is moving. We've generally kept the
2 pace of that with our own programs at our plants with
3 configuration risk management and our maintenance rule
4 programs.
5 Next slide, please.
6 Again, for perspective, no nuclear plant
7 either caused or contributed to the August 14th event,
8 and all of the affected plants performed as designed.
9 You need to remember those, those important factors.
10 Arguments about the dominance of the
11 summer events I think needs a little closer
12 examination. First of all, you know, if you look at
13 this statistically, some of this is absolute data, and
14 some of it is relative data, and if you look at it on
15 a relative basis, you get a pretty skewed picture, and
16 I think some of that came out in the last two slides
17 that NRC presented.
18 First of all, a lot of our data is skewed
19 by one event, the August 14th event, which, again, all
20 of our plants did perform as designed in the August
21 14th event.
22 The root cause of all these loop events is
23 generally not correlated to season. Now, this is an
24 important point. If, in fact, the summer is driving
25 a large increase in loop events, one would assume that

1 if you go down and look at the root cause of these
2 summer events that you'd see a seasonal basis or a
3 seasonal driver for that higher frequency, and in
4 fact, that's not the case. I'll get to some more
5 details on that later.
6 Emergence of longer duration grid events
7 as a higher percentage of the total loop events is
8 really driven by the fact that we have reduced the
9 number of the shorter duration or the plant centered
10 events over the last 20 years. It's pretty parallel,
11 I think, to the performance we've seen in or the
12 outcomes we've seen from PRAs in general that have
13 shown that you've reduced plant risk by roughly an
14 order of magnitude over this period primarily by
15 dealing with plant centered risks and improving our
16 plant performance, design operations, and so forth, to
17 reduce our PRA numbers or core damage frequency
18 numbers, and that what that leaves you, of course, is
19 a higher percentage of external event contribution to
20 risk.
21 The same thing is happening here with the
22 grid. As we continue to improve our plant
23 capabilities, the residual that is left is going to be
24 more externally driven.
25 The total number of loop events over

1 history has actually gone down over this 20-year
2 period. So I guess the point there at the end is that
3 no good deed goes unpunished as we continue to improve
4 our plant safety. The focus gets on that residual
5 risk, and that's where we're focused today.
6 Grid weaknesses can occur at any time.
7 It's not strictly a summer related phenomenon. You
8 have to be on guard 12 months out of the year. Just
9 some simple points here. The longest recent
10 occurrence of a sustained grid weakness that lasted
11 for 776 hours -- that's quite a period of time --
12 occurred in California in January and February. This
13 is when they were less than 1.5 percent reserve margin
14 for an extended period of time.
15 The major northeast blackout that occurred
16 that kind of drove the creation of EPRI occurred in
17 November. Picked up last week's Nucleonics Week.
18 Weather conditions forced four parallel units off the
19 French grid. This event occurred at the end of
20 December, 6,000 megawatts down.
21 So there are events throughout the year,
22 and I'm going to say a little bit more about the
23 summer connection here at the bottom of this slide and
24 later, but we need to recognize that this is not just
25 a simple, you know, worry about this in the summer and

1 not 12 months out of the year.

2 Grid weaknesses can occur any time. If

3 you look at some of the charts that we're shown by NRC

4 having to do with reserve margin, reserve margin is a

5 relative term, and if you've got a lot of plants out

6 and spring outages and fall outages, whether it's

7 nuclear plants or fossil plants, and your reserve

8 margin can come down quite a bit if you've got

9 unexpected warm weather in the spring or something

10 like that.

11 The next bullet is an example of that when

12 they had a pretty serious problem in California just

13 April of this last year, because it warmed up quite a

14 bit before all the plants were back on line from their

15 spring outages.

16 The primary causes of loop events over the

17 last ten years and in order of importance are shown

18 here at the bottom of this slide. Random equipment

19 failures, adverse weather conditions, the August 14th

20 event which was the third largest contributor which

21 was really mostly maintenance related, driven out of

22 the grid, and then random human errors. These are the

23 first four. There are others. Animals created quite

24 a few of them as well. That's number five and number

25 six.

1 But the important point is that of these
2 four primary causes or root causes, none of them are
3 really specifically restricted to a summer type of a
4 problem. Random equipment failures can occur 12
5 months out of the year, as can adverse weather
6 conditions. We have adverse weather conditions in the
7 winter as well as in the summer.
8 So we just need to keep this perspective
9 on this summer data.
10 The draft generic letter talks about the
11 summer months being May through October. That's a
12 five-month span, and there's also concern about
13 hurricanes. I think Brian mentioned that this
14 morning. Those, as we know from this last year's
15 bitter experience in the South, extended into November
16 and I think even early December.
17 So we're kind of categorizing a six-month
18 period, five to six-month period here as a period of
19 concern, and if we end up taking, you know, an extreme
20 position here that basically says no maintenance on
21 plant electrical equipment during an extended period
22 of time like that, we could have some unintended
23 consequences.
24 So I think from a more sophisticated risk
25 approach we would prefer to see a look at this. It's

1 not just as simplistic as watch out for the summer and
2 not any other time.
3 The top bullet here just repeats the point
4 I made earlier about the conclusions of NUREGs
5 analysis of the station blackout rule. It was
6 effective in meeting NRC's expectations and, in
7 particular, diesel reliability has been higher, higher
8 than was originally anticipated when the rule was
9 crafted, and this has kept our overall station
10 blackout effectiveness quite high over the years.
11 The likelihood of grid induced loop is a
12 function of plant location. Again, not a one size
13 fits all solution here. We worry sometimes about
14 plants at ends of transmission lines. There are a
15 number of plants in situations like this, the Florida
16 peninsula and so forth. They have a different
17 situation than the rest of the country.
18 Weather vulnerable regions. Again, this
19 is not just summer phenomenon. There are different
20 weather concerns at different parts of the countries
21 at different times.
22 Industry's capability against loop events
23 has improved greatly since the days of the station
24 blackout rule implementation. It's not that we've
25 simply complied with the coping times and the station

1 blackout rule and haven't done anything since then.
2 We've done a huge amount of work. You're going to
3 hear a lot more from what INPO has done in this area.
4 We've created a lot of tools that have been very
5 helpful in helping plants, and of course, the advent
6 and continued improvement in plant specific risk
7 models has helped a great deal in dealing with grid
8 reliability.
9 Next slide.
10 We have a forum, an EPRI committee, in
11 effect, that is called the configuration risk
12 management forum. It's actually meeting concurrently
13 as we speak here. Their annual forum is occurring
14 this week down in Florida.
15 This forum is the focal point for
16 industry's assessment of CRM practices across the
17 fleet. CRM, of course, is essentially a real time
18 capability to analyze plant risk and to be able to
19 make operational decisions by operations people,
20 maintenance people and so forth, to optimize the
21 timing of those factors that you have control over,
22 such as placing equipment out of service for
23 maintenance.
24 The workshop at the same place as we speak
25 is explicitly including discussion of grid related

1 events in the agenda, and there are NRC personnel in
2 attendance.
3 CRM is focused on managing risk due to
4 both unplanned and planned conditions as primarily
5 those are controlled by operators, and it explicitly
6 includes consideration of grid issues. Based on a
7 lengthy survey that we did within the CRMF in 2004, a
8 little over a year ago, we've determined that grid
9 reliability is being addressed in the majority of
10 plant models. You'll see at the bottom of this 85
11 percent of the plants responded, and of those 85
12 percent, the vast majority of them are either
13 quantitatively or qualitatively addressing grid
14 performance in the way they do their CRM modeling, and
15 obviously their management decisions on making outage
16 decisions and maintenance rule decisions.
17 Next slide, please.
18 The survey that was conducted in 2004
19 examined three specific type of grid disturbances:
20 severe weather, switchyard maintenance activities, and
21 other external events that could affect the grid,
22 including grid instabilities, regional flooding,
23 forest fires, and other things that are in effect.
24 And conditions affecting risk may or may
25 not be under the control of plant staff. Obviously

1 plant staff has control over switchyard maintenance,
2 but it doesn't have control over maintenance that's
3 being done, you know, 100 miles away from the plant.
4 It doesn't have control over weather
5 obviously, but at least it can anticipate weather
6 conditions.
7 We've talked a lot about quantitative and
8 qualitative means being used to assess grid
9 performance and grid reliability. This is kind of a
10 repeat of a point that the gentleman from San Onofre
11 made before the break, and that is that we can do a
12 reasonably good quantitative job of assessing
13 switchyard reliability, and we can quantitatively,
14 although not with the same degree of accuracy, but at
15 least quantitatively make some reasonable assumptions
16 about weather related events, if there's a storm
17 coming or stuff, you know that you've got a heightened
18 condition of risk.
19 The area that EPRI has, as far as we can
20 tell from all the CRM activities in the industry, have
21 not been able to quantitatively model is the grid
22 itself. We've been working on this for a number of
23 years. We've got a pretty significant cross-sector
24 effort at EPRI with our nuclear sector, our fossil
25 sector, and our power delivery sector working on these

1 grid reliability issues, and although we've done a lot
2 of pretty sophisticated modeling of the grid, the
3 ability to feed back a reliability number back to the
4 plant on what the condition of that grid is at any
5 point in time is a pretty impossible task at the
6 present time.
7 CRM obviously requires increased
8 maintenance controls when conditions indicate, but
9 it's determining when those conditions really indicate
10 that that is the tough thing to do. I mentioned that
11 we've got a pretty significant cross-sector activity
12 at EPRI looking at grid related risk and performance.
13 We're involved in establishing industry-wide guidance
14 across the board in both plant and grid areas. You
15 can see the list of the things that we've got covered
16 there.
17 We also addressing a lot of equipment
18 reliability issues through either configuration risk
19 management or pretty extensive switchyard users group,
20 transformer users group that's looking at those
21 aspects of plant performance working hard on such
22 things as switchyard breakers, transformer liability
23 and so forth, with guidance on both maintenance and
24 operations of those components for improved
25 reliability.

1 We're looking at turbine generator
2 torsional problems that have cropped up as a result of
3 grid oscillations. We're going a lot of work with
4 devices for voltage support for maintaining VARs.
5 The next slide, as I mentioned, we've
6 issued about 50 reports over the last 20 years on
7 reliability. These are the last four that have been
8 issued related to off-site power reliability and
9 causes of losses of off-site power. We do a
10 cumulative update about every year or so.
11 And finally, as I said, the ongoing CRM
12 workshop in Florida has taken away the top EPRI
13 experts on grid performance and grid reliability. So
14 I'm filling in and probably will not be able to answer
15 as many questions as these guys would. Frank Rahn is
16 the overall coordinator of our grid reliability work
17 and works with people in power delivery and
18 generation.
19 His boss, John Gaertner, and Ken Canavan
20 are deeply involved in the PRA side of this. Wayne
21 Johnson is our equipment reliability expert for grid
22 related matters.
23 And that's it.
24 MR. CAMERON: Okay. Thank you very much,
25 Gary, Bill, Dale.

1 We do have the hard copies of the slides
2 available out in the back. So all of those helpful E-
3 mail addresses and hone numbers will be on there.
4 You just heard a presentation on the data
5 and on the implications of the data, and I guess the
6 focus of this discussion should be on what the
7 implications of the data are, and I think it would be
8 helpful for Mike Mayfield and all of his staff if you
9 had suggestions on how the GL should be adjusted based
10 on what your view is about the data, please bring that
11 forward.
12 I'm going to give the panelists an
13 opportunity if they want to ask a question or comment
14 on what the other panel has said before we go out to
15 all of you.
16 Gary, anything at all? Bill?
17 MR. RAUGHLEY: I had a couple
18 clarifications. One is I don't think the NRC ever
19 said no maintenance. What we're trying to do is get
20 the proper numbers used in the assessments of risk
21 when you do maintenance tests outage activities.
22 Ma'am, if you could go back to my next to
23 the last slide. That one -- next one. One more.
24 There you go.
25 With regard to this plant, you know, the

1 fact that I said that the plants had eliminated the
2 plant centered events, if you look on these curves, it
3 provides a way to visualize the problems, is you have
4 a relatively flat, large number of events which are of
5 low consequence. They're actually much, much less
6 than 100 minutes, and those are the ones that are
7 largely plant centered, and those have been
8 eliminated.
9 The risk significant events are on the
10 straight part of the curve, and those are the ones
11 that remain. So what they've done is you have
12 eliminated the low risk events from a risk
13 perspective. It's not to say that the plants haven't
14 done an outstanding job in eliminating the actions to
15 prevent recurrence of the problems, but from a risk
16 perspective, you haven't done anything.
17 MR. CAMERON: Okay. Dale, anything?
18 MR. RASMUSON: Yes, just one
19 clarification. In the comments that we received from
20 EPRI and from others on our reports in that regarding
21 the August 14th event, a lot of the comments focused
22 that we ought to count it as one event, but I'd just
23 like to point out that that is changing the definition
24 of loss of off-site power. We're not saying that the
25 definition that we've used that you saw here was that

1 it affected the plant, and we're calculating risk of
2 the plant.
3 There was one event in August 14th, but
4 it's not a loss of off-site power event, you know. I
5 mean according to our definition. According to our
6 definition, there were eight occurrences of loss of
7 off-site power where plants lost -- their safety buses
8 went dead and the EDG started, and so that's what we
9 are counting, and with the fact that if you look at
10 the distributions, that's when the events occurred,
11 changing the subject here.
12 The events occurred during the summer. I
13 mean, no one can argue with that, you know. We're not
14 saying what the causes are. We're not looking at
15 that. We're just saying they occurred during the
16 summer. Those are the facts.
17 And so we can go and say some other
18 things, but that's when the events occurred. And
19 people bring up like other blackout events, but you
20 know, like the '96 grid blackout in the West. No
21 nuclear power plants lost power to those things, and
22 so you know, they're not relevant to our PRA analyses.
23 So that's just some clarification I'd like to point.
24 MR. CAMERON: Okay. Thank you, Dale.
25 And just a couple of words about lunch,

which is always important to people. We originally were going to give you lunch at 11:30 so that you could avoid the rush of lunchtime in Bethesda.

We're running late now. So we're just going to keep going for a while with you and then take the hour long lunch break, but we won't go longer than 12:30 with this.

But with that comment, Alex, do you want to come up?

All right. Alex Marion, Nuclear Energy Institute.

MR. MARION: Alex Marion, NEI.

Thank you.

I have a dilemma. At NEI we represent the industry in interactions with the Nuclear Regulatory Commission. Here we have a situation where the organization that the industry relies on for these kinds of analyses and data assessment is EPRI, and they're saying one thing relative to the historical performance of the grid and how you characterize and assess events, et cetera.

Then we have the NRC, on the other hand, taking a different approach, and I understand what you said, Dr. Rasmuson, in terms of how you analyzed the events, but we're in a quandary. Is there any way to

1 bring the two parties together so that we get a common
2 understanding and treatment going forward?
3 Because I see the different opinions just
4 compounding over time and the gap getting broader
5 instead of coming together to a common approach. So
6 I would just like to offer as a potential follow-up
7 action item for us to get together and get into some
8 down-to earth dialogue so that we don't have these
9 inconsistencies in interpretation and assessment.
10 MR. CAMERON: Okay. Thank you.
11 And obviously that's not only just a
12 short-term related to the GL, but a longer term.
13 John, do you want to talk to that?
14 Go ahead and please introduce yourself.
15 MR. KUECK: This is John Kueck at the
16 Advisory Committee for Reactor Safeguards, although I
17 am not here representing the Advisory Committee but
18 myself.
19 As Gary said, this work has been going on
20 for 20 years, and I guess maybe him and I are the
21 oldest folks in the business since I started that work
22 back in the '80s myself.
23 MR. CAMERON: We'll let the record show
24 that.
25 MR. KUECK: Yes. Looks can be deceiving.

1 Yeah, that's a great comment that I think
2 Alex has made, and you probably need a third party in
3 this, and that's NERC. I think it would be important
4 to get NERC's views on this. I know when Bill
5 released his report there were comments raised by both
6 NERC and NEI, and they're very contrasting.
7 When you look at one set of comments from
8 the people that do this for a living, you get a
9 different perspective than NEI. So I think it's very
10 important that all of these statistics has a
11 fundamental engineering basis as to why they represent
12 what they represent, and unless you have that basis,
13 statistics are just numbers.
14 So I think it's important; it's extremely
15 important to probe down and find out the basis and
16 then agree on that basis. I mean, I think no one more
17 important to get involved in that process would be
18 NERC.
19 And I guess from having done this work for
20 all these years, I mean, we're only kidding ourselves
21 if we believe nothing has changed in the last 20
22 years. A lot has changed in the last 20 years, and
23 things are going to continue to change, as you can see
24 with the plots that Bill had put up earlier about the
25 reductions in spending reserves and so on.

1 So I think it's not only today that we're
2 needing to deal with this problem. We also have to
3 think what's going to happen over the next ten years.
4 When they came in for advanced reactors and they
5 talked to the Commission, the driving need for new
6 reactors is based load capacity by 2015.
7 Okay. What's going to take us to 2015?
8 I think we have to look also into the future in this
9 and say are we doing the right thing. Are we getting
10 prepared to carry this load into the next generation
11 of nuclear power plants?
12 Because if we don't do it now, there is
13 not going to be a new next generation. We have to be
14 able to address the most important risk contributor to
15 nuclear power plants today, and that is station
16 blackout. Anybody that does risk knows that that's
17 driving things. So just a few comments from my
18 perspective.
19 MR. CAMERON: Okay. Thank you, John.
20 And I'm going to ask the panel if they
21 have any comments, but two issues on the table. One
22 is a longer term action, not just int he NRC's lap,
23 but in EPRI's, NERC, but is there a mechanism that can
24 be used to try to reach consensus on the implications
25 of the data?

1 So I know that Mike Mayfield has that on
2 his action list. Short term, again, Alex
3 characterized it. There's a difference of opinion
4 here on what the implications are for the GL. I guess
5 that the NRC staff would be interested in any comments
6 on how the GL might be changed to accommodate these
7 different opinions.
8 So I'll leave you with that for a second,
9 and then I'll go to Dale and Bill and Gary to see if
10 they have any comments at all on what we heard from
11 Alex and John Kueck.
12 Dale.
13 MR. RASMUSON: I just wanted to say that,
14 you know, we have met with EPRI, you know, to
15 coordinate some of these things, and we do differ on
16 the August 14th event. There is a difference on that,
17 but the definition that we have been using is the
18 definition that has been around since 1032. You know,
19 that was the definition that was used there for loss
20 of off-site power.
21 And so we're not changing definitions at
22 all in that regard. I'd just like to emphasize that.
23 MR. CAMERON: Bill, anything you want to
24 say in regard to the dilemma that Alex has and the
25 suggestion that he made?

1 MR. RAUGHLEY: As Dale said, we've met, I
2 think, three times with EPRI. Dale is the last word
3 on the statistics. We do have the same raw data.
4 Dale did base his risk. Baseline risk is based on the
5 minimum recovery time. He's done sensitivity analysis
6 for the actual times, and with regard to the numbers
7 of events, one other major point of disagreement is
8 EPRI definitions include events when the reactor is
9 not at power, which have absolutely nothing to do with
10 station blackouts. So they don't enter into Dale's
11 statistics, and that's the fundamental difference in
12 the numbers, is that they exclude -- you reduce the
13 summertime event from eight to one, and then you add
14 eight non-power events that are largely in the winter,
15 and then that masks the summertime phenomena.
16 So I think we understand the difference,
17 and I don't know how long we want to beat this horse
18 to death, but Dale is using numbers that have been
19 around since 1970-whatever, you know, when John was a
20 youngster with hair, and he hasn't changed a thing.
21 It's just pumping the same data into the same formulas
22 and getting the answer, and it shows change, and I
23 think we need to respond to it.
24 And, yes, we would love to meet with the
25 industry and keep this discussion going for the long

1 term, but I think for the short term, the numbers are
2 the numbers. You know, unless we want to change the
3 definitions, and again, that's a long term thing.
4 MR. CAMERON: Okay. Let's ask Gary to
5 comment on this.
6 MR. VINE: Sure. I appreciate Alex's
7 comment. I think to one of the points made here about
8 including shutdown events or not, we think that
9 shutdown events, even though the plant is down at the
10 time, is relevant operating experience to learn from,
11 and so it does tell you if the plant was up what would
12 have happened, and so we look at it more broadly, and
13 I think that helps balance the picture.
14 But I think the most important point to
15 make here is that the differences of view between the
16 industry and the NRC this time around as compared to
17 20 years ago when the station blackout rule is
18 originally being formulated are fundamentally
19 different.
20 In the early run through this in the '80s,
21 it really was the raw data that we disagreed about,
22 and we worked through a process to get to a joint
23 understanding of that raw data, and then things went
24 pretty smoothly, and in fact, our MOU with the Office
25 of Research is pretty much restricted to analyzing the

raw data, getting that understood and agreed to on both the industry and the NRC side, and then we give the data to NEI and RES gives it to NRR, and NRR and NEI work on how to interpret it and what it ought to mean in regulatory space.

But we are then pretty successful in getting agreement on the raw data. In this particular case, although there are some differences of opinion on the raw data, the fundamental difference, I think between what we're coming up with and what RES is coming up with is that interpretation of the data as it goes forward to the decision makers, and we just see the data differently than does RES in terms of what it ought to mean for plants in the country and what they ought to be doing about it.

So we're really into an area of judgment that really is not just a difference of opinion on data, but really a judgment issue between NRC and industry as to is this picture that we see here significantly different than what was expected in the station blackout rule. Is it significantly less safe than it was at the time the station blackout rule was written to justify major new actions?

And that's not a data question, and it's not an EPRI question. That's an NEI and NRC question.

1 MR. CAMERON: Okay. Let's hear from Rich
2 Barrett. Rich.
3 MR. BARRETT: Thank you, Chip.
4 I'm Rich Barrett. I'm with the Office of
5 Research at the NRC.
6 And I can certainly appreciate Alex's
7 question. You know, we have a number of regulators
8 and regulated entities here today, and they've got to
9 make decisions about where to go next in putting out
10 this generic letter and in responding to this generic
11 letter, and it can be confusing when you're hearing
12 different perspective from the research entity of the
13 NRC and the principal risk entity of the industry.
14 And I can say certainly from the
15 perspective of the NRC that we are committed to
16 continue this work and to cooperate with EPRI and
17 others to get to the very best possible insights from
18 what the data are telling us so far and what the data
19 in the future will be telling us as we see more
20 experience and we pile up more years of experience in
21 this area, and as the grid continues to evolve and the
22 performance of the grid continues to evolve.
23 What I thought was interesting this
24 morning in the three presentations was not just the
25 information about the numbers of frequencies of losses

1 of off-site power, the durations of losses of off-site
2 power, but I think it's important as both Bill and
3 Gary did to go beneath the data and ask yourself
4 what's going on here. What's going on in the grid?
5 For Gary, from Gary's perspective, he took
6 a closer look at some of the root causes, and I think
7 it's important to look at the root causes, and some of
8 these root causes that you saw are not seasonally
9 related. We know that there are others that are
10 seasonally related.
11 I think you also saw that there were some
12 important insights here related to other trends,
13 plants that are near I believe he called it the edge
14 of the grid, plants that are in extreme weather
15 situations. These are all questions that need to be
16 considered in response to this generic letter.
17 Conversely, Bill presented some
18 information that we've gotten, we, the NRC, have
19 gotten from NERC related to precursors to loss of off-
20 site power, and I think it's very important to take a
21 look at these deeper -- a deeper look at some of the
22 things that relate to the vulnerabilities of the grid
23 or the reliability of the grid both from the trends
24 from year to year and the trends from season to
25 season.

1 One of the things I saw this morning that
2 I hadn't seen before was what appears to be an upturn,
3 more and more of an upturn during the December time
4 frame than there was in previous data, and I think
5 that's a long-term challenge for all of us.
6 But at the moment, I think there is no
7 question that we have to address the questions that
8 have been raised. Gary said that a lot has changed
9 and a lot has improved in the electrical systems since
10 the station blackout rule was put in place, and he
11 gave some examples, which I'm not in a position to
12 evaluate, but I think it's also clear that there is a
13 difference in the grid. I think it's also very clear
14 that there are some differences in the way in which
15 the plants are being operated, the technical
16 specifications have been changed significantly with
17 regard to allowed outage times, and it's difficult for
18 us at the NRC to evaluate how all of that plays out in
19 terms of the risk to the plant and continued
20 compliance with the regulations.
21 And so that's the reason why what to some
22 extent has been a research question because it's now
23 moving more and more over the past two or three years
24 into the regulatory arena and the issuance of this
25 generic letter.

1 So I guess my bottom line would be, yes,
2 absolutely, Alex, we need to go forward, the Office of
3 Research and NRR and EPRI, to continue to try to maybe
4 get back to what Gary said was the case a few years
5 back where we understand each other's analyses and we
6 can come to agreement, and in the meantime we need to
7 continue to gather more information about the health
8 of the grid. We also need to take a very close look
9 at the responses to this generic letter to make sure
10 that we understand how the plants are being operated.
11 MR. CAMERON: Great. Thank you. Thank
12 you, Rich. A very positive.
13 I guess I would just put the question,
14 again, in a different way. Is there anything in the
15 generic letter now based on the NRC's interpretation
16 of the data that would produce unintended
17 consequences? Is there anything that should be
18 adjusted or changed in the generic letter?
19 And I guess that's a good segue for Mr.
20 Thorson.
21 MR. THORSON: James Thorson, Detroit
22 Edison.
23 I guess having listened to this recent set
24 of presentations, the Question 5 "Charlie" on the
25 draft generic letter, is there a seasonal variation in

1 the stress on the grid in the vicinity of your nuclear
2 power plant site? Is there a seasonal variation in
3 the loop frequency? And then if yes, discuss when
4 they do occur and what's the magnitude of the
5 variations.
6 I guess, you know, one of the objectives
7 for this form was for the industry to kind of
8 understand what the NRC's expectations was and how we
9 would provide information to you with respect to this,
10 and I guess I'm a little reluctant to get quantitative
11 in my response to the NRC to this question based upon
12 the general, I guess, lack of agreement or on how to
13 interpret the data.
14 And then secondly, in particular, the
15 seasonal variation and the loop frequency for our
16 plant. I'm hoping that our frequency is such that I
17 can't detect a variation. So I guess what I'd like to
18 ask specifically: is it acceptable to remain
19 qualitative when we answer this question or are you
20 requiring a quantitative assessment?
21 MR. CAMERON: Good question. Bill, are
22 you down?
23 MR. RAUGHLEY: NRR needs to answer that.
24 MR. CAMERON: And who are we going to go
25 to, not NRR but Research?

1 MR. ALEXANDER: No, this is NRR.

2 MR. CAMERON: Oh, it is. Sorry, Steve.

3 Sorry.

4 MR. ALEXANDER: Oh, yeah. That's all

5 right. Oh, I'm not insulted. Maybe research is. I

6 don't know.

7 (Laughter.)

8 MR. ALEXANDER: But I'm perfectly happy to

9 be part of either one of them as long as I can, you

10 know, make a contribution.

11 Anyway, no, that's one of the maintenance

12 rule related questions, I think, and of course, it's

13 information that we want to know in general for the

14 generic letter, but quantitative and qualitative are

15 both valid kinds of information. If it's something

16 that you can't quantify, then what we want to know is

17 from that if we don't concentrate on loop frequency

18 per se, are there seasonal variations however you

19 define the reliability and availability of off-site

20 power and in your specific area.

21 We recognize, for instance, that looking

22 at national averages that seem to show there's more

23 loop events in the summertime may be misleading

24 because some plant in certain areas may have more

25 stressed conditions at other times perhaps due to

1 reduced generation capacity, such as in Southern
2 California in the wintertime, for example.
3 So what we want to know is, and
4 qualitative is fine, what are the variations in grid
5 reliability and availability and off-site power
6 availability that you see in your area, if you see
7 any.
8 If the answer is there aren't any, then
9 that's a valid answer.
10 MR. CAMERON: Okay. Great. So in other
11 words, I'm not sure the way it's phrased, but the
12 intent of the generic letter would allow specific
13 companies to answer that question based on their
14 specific situation about what do you see as variations
15 in grid reliability.
16 It could be seasonal. It could be
17 something else?
18 MR. ALEXANDER: The intent we wanted is to
19 get the story on that from each individual plant.
20 That's why we're sending it to everybody.
21 MR. CAMERON: Okay. Thank you very much.
22 Let's go to Southern California.
23 MR. ROSENBLUM: This is Dick Rosenblum,
24 again.
25 Going to the exact same questions, I'm

1 going to try to honor the way the question was asked.
2 Is there anything in the generic letter that we'd like
3 clarified or changed?
4 The same Question 5, I guess it's (c) and
5 (d). The one point I would make is I would like to be
6 sure that the questions being asked are precisely the
7 questions that are intended to be asked, and I say it
8 for this reason.
9 There is an imbedded assumption that
10 somehow grid stress relates to loop frequency, and
11 some of the data I heard and some of the discussions
12 I heard in this session pointed out that loop only
13 occurs when the plant is operating by the definitions
14 we're using -- station blackout. Excuse me. And
15 plants tend to operate in California more in the
16 summer. So the frequency will go up.
17 I'm not sure what's what was really
18 intended. If the question is really about the grid,
19 then it doesn't matter whether the plant is operating
20 or not. The grid has a certain number of events.
21 They do include losses of power whether the plant is
22 operating or not. That's one set of data that
23 responds to one question: what's the grid doing?
24 Firm load interruptions, rolling
25 blackouts, service interruptions, service reliability

1 has nothing to do with that, and all of the
2 presentations, both Gary's and William's, had service
3 reliability interruptions in them that are not germane
4 in my personal opinion.
5 So we have to be really careful, and I
6 would ask people to go back and look at the generic
7 letter and make sure the question you're asking, which
8 we will answer, is precisely the question that's
9 intended to be answered and that the data will then be
10 used to answer that question, not say because plants
11 operate more in the summer than in the winter, the
12 grid is less reliable in the summer. Those two things
13 are not related.
14 So we have to keep the data sets
15 consistent, and we have to make sure that we bring to
16 bear the data that really applies to the question
17 being asked.
18 I'm not sure. I think among the experts
19 that's occurring. I'm not sure among the decision
20 makers that's occurring.
21 MR. CAMERON: Great, and that goes back to
22 the point you brought up earlier about grid
23 reliability versus system reliability.
24 Does the NRC staff have anything that they
25 want to say on that issue? I think it's exactly the

1 type of thing that we're looking for a comment on.
2 Anybody want to say anything about that? You don't
3 need to. I'm just giving you an opportunity.
4 Research or NRR this time?
5 MR. ALEXANDER: Whatever, as my son likes
6 to say. No, it doesn't really matter, but in this
7 case, yes, NRR still, I hope.
8 No, seriously, if you take a look at
9 Question 5(c), it says there a seasonal variation in
10 the stress on the grid in the vicinity of your nuclear
11 power plant site. Is there a seasonal variation in
12 the loop frequency?
13 We didn't mean to assume that there's an
14 iron clad causal relationship between those two. We'd
15 like to get both sets of data. We'll maybe then try
16 to decide what it means, but we'd like to know are
17 there seasonal variations in the stress on the grid.
18 Question D maybe should have included the
19 stress part also, but that's the intent. We want to
20 find out, and we also, at least in the staff we
21 recognize the difference between service reliability
22 and grid reliability.
23 We're concerned about grid reliability in
24 terms of what's available to the nuclear power plant
25 to maintain the safety buses for whatever event, and

1 so we want to know if there is a reason, for example,
2 in July at a given plant, which maybe is more of the
3 average, to factor in something to your grid risk
4 assessments that is not needed at other times of the
5 years. Maybe there isn't, but that's what we're asking
6 the question for, is to find out.
7 MR. CAMERON: Does that explanation help,
8 Dick? And should there be any words added of
9 clarification along those lines into the GL?
10 MR. RASMUSON: I think that answer does
11 help, and it's what I perceived by listening to this
12 whole discussion, but I do believe the GL needs to be
13 clarified about exactly what question is being asked
14 and what that means.
15 So for instance, don't tell us about
16 service reliability issues. What is grid stress? You
17 know, what is a loop? So that the people that answer
18 the question that's truly intended.
19 MR. CAMERON: That's great.
20 Yes, sir. It's Dan?
21 MR. GOLDSTON: That's right. Dan
22 Goldston, South Carolina Electric & Gas.
23 In Slide 4, number four from Dr.
24 Rasmuson's and Raughley's presentation, they gave some
25 definitions of loss of off-site power and station

1 blackout, and then later on you seem to imply that the
2 station blackout definition may be incomplete because
3 you only address that if the plant was on line.
4 That's not in the definition in your slide, and--
5 MR. RASMUSON: No, loss of off-site power
6 can occur at either where the plant is either up or
7 shut down. It is loss of off-site power to the safety
8 bus irrespective of whether the plant is up or down.
9 MR. GOLDSTON: That's all safety buses.
10 Okay. So that's clear on that.
11 Now, station blackout, wasn't that the one
12 that you did say it mattered?
13 MR. RAUGHLEY: Yes, sir. If you look at
14 the definition of station blackout in the regulations,
15 it starts with the turbine trip. It's the loss of all
16 AC power following the turbine trip. That's when you
17 have the decay heat. When you shut down, you don't
18 have much.
19 MR. GOLDSTON: So perhaps it would help me
20 at least if the definition that we used here was
21 exactly the same that we used elsewhere in all the
22 other documents, including the generic letter, because
23 I just got confused. I didn't realize that there was
24 that discrepancy.
25 MR. CAMERON: Okay. Is there any reason

1 why we can't be consistent?

2 Okay. Well, I guess the point is taken,

3 right, Ronaldo? Do you have that?

4 MR. JENKINS: Sure.

5 MR. CAMERON: Okay. Before we go over to

6 San Onofre, let's go to Paul.

7 MR. GILL: Yeah, I just want to follow up

8 on the --

9 MR. CAMERON: Paul Gill.

10 MR. GILL: Paul Gill.

11 -- station blackout.

12 PARTICIPANT: NRR.

13 MR. GILL: NRR. Thanks.

14 The definition for station blackout is

15 loss of all AC power to the safety buses, excluding

16 the batteries. Okay? So if you have battery power

17 inverters, they're not part of the station blackout

18 definition. It's all AC power that is from the off-

19 site system as well as from the on-site system to all

20 safety buses.

21 So that's the basic definition that is

22 used in the rule.

23 MR. CAMERON: Okay. Thank you. Thank

24 you, Paul.

25 If we need to go for clarification on

1 that, we will. Let's go to this gentleman, Parviz
2 Moieni from San Onofre. Again, as Dick said.
3 Question 5(c), it seems we are talking
4 about risk. What is the staff expectation that -- who
5 is the best group at the nuclear power plant to answer
6 this question? Do you think this is -- because this
7 is risk assessment. So usually PRA group has a role.
8 Do you think PRA group can answer this question or
9 this should go to the grid people?
10 And what type of data we should look at to
11 answer this question? Because right now I'm looking
12 at it, and I thought I could answer this question.
13 Right now I don't think I can answer this question.
14 So who is going to answer this question?
15 And a second part of my question is that
16 maybe they can answer this question. We saw a lot of
17 viability, seasonal variability and low plant
18 duration. Do you have information also on the
19 regional like western grid, eastern grid? Are they
20 sensitive through the seasonal or this is just an
21 overall the nation's frequency and duration?
22 MR. ALEXANDER: Let me answer the first
23 question. The answer is yes to your first question.
24 In other words, any group at the plant that has
25 meaningful information to contribute we'd like to get

1 that incorporated into your responses. PRA can answer
2 part of it. Operations can answer part of it.
3 Anybody that's got useful information to contribute,
4 we'd love to hear about it. It doesn't have to come
5 from one group.
6 MR. CAMERON: Okay, and if you need to put
7 a finer point on that, maybe we can discuss that off
8 line with Steve.
9 Quickly, anything on the regional issue?
10 MR. RAUGHLEY: Yes, we do have sorts or
11 you can sort the data to show the differences between
12 the eastern Texas and the western interconnection, and
13 I divided up, you know, had the two NERC bins there,
14 you know, NERC definitions I've been following.
15 And then the events in the western
16 interconnection are largely capacity events and events
17 in the eastern interconnection are largely operating
18 reliability. So you've got both ends of the spectrum,
19 depending on where you are.
20 MR. CAMERON: Okay, great. Thank you,
21 Bill.
22 We're going to take two more questions,
23 and then we'll break for lunch and we'll figure out
24 where we are on this when we come back from lunch.
25 But let's go to -- it's Phil and then

1 we'll go to Jennifer.

2 MR. BRADY: Yes, Phil Brady, PPL,

3 Susquehanna.

4 This one, I'm looking at the data that was

5 provided on like the grid disturbances, the forecasts

6 as far as capacity margin, TLRs. All that data is

7 dated, and I'm not sure how we are going to relate it

8 to our specific plant and be able to then give any

9 sort of information back.

10 It appears you've used that to look at a

11 summer, you know, as being the worst time frame, but

12 yet it could be very much regional as where the

13 problem is in the grid, and therefore, you know, the

14 question may be that when you look at this data, it

15 would be to get much more specific as far as what

16 region, what location had the problems with load

17 flows, had problem with these disturbances to get a

18 better feel for what we need to be then in our

19 response.

20 MR. RAUGHLEY: We agree. I just shared

21 four or five slides. I was told to keep this to 15,

22 20 minutes, and as I mentioned, I'll give you the --

23 what we do have is on our Website. It's ML043000125.

24 So if you want to -- ML043000125.

25 MR. CAMERON: I'll write that on the flip

1 chart, too, for everybody.

2 But let me ask a question of Mr. Alexander

3 again. In terms of that question, the response you

4 gave before about as perhaps needs to be clarified a

5 little bit as you discussed, but your explanation from

6 before about looking for variations, is that relevant

7 to this gentleman's question or am I off the mark here

8 in terms of what we're looking for? Does that help

9 him out any?

10 MR. ALEXANDER: Well, what we're looking

11 for is we might be able to, from the data that we get

12 from each individual plant, in our discussions which,

13 of course, will be ongoing with Research and with

14 EPRI, the data that we get or the information that we

15 get if it's not, you know, in the classical form of

16 data per se, but any insights that we can gain from

17 the responses from each individual plant, from that

18 information we might infer some patterns that could

19 emerge about regional differences as well, and I think

20 this question was focusing on regional differences.

21 And we already have some information as

22 was already said about what some of the different

23 causes of things are in different regions being

24 related to operation in one area more so and

25 historically related to generation capacity losses in

1 other areas.

2 And maybe patterns like that will emerge

3 when we start to get the information. So the answer

4 is I guess until we sort of see the data we don't know

5 if there's going to be a correlation necessarily

6 that's identifiable region to region.

7 MR. CAMERON: Okay. Thank you very much.

8 And we're going to go to Jennifer for her

9 comment or question, and then we're going to take a

10 break. Keep in mind I think Bill said a Website this

11 -- when you go to our Website, this ML number is an

12 accession number for the so-called ADAMS system.

13 Okay? Just in case you might be confused.

14 Jennifer.

15 MS. WEBER: Just real quick, if I'm

16 understanding what you're trying to accomplish here,

17 maybe focusing on seasons is predetermining the answer

18 you're going to get whereas what Mr. Vine said was

19 things like reserves can be a very important function,

20 and I'm wondering if I'm understanding it correctly if

21 what you're trying to get at in C&D is to ask are

22 there definable periods of inquired risk to off-site

23 power adequacy, for example, seasonal variations or

24 low reserves, and -- okay. That's it.

25 Oh, and just to mention that stress on the

1 grid is not necessarily -- having the grid not
2 stressed doesn't mean you're off-site power is good.
3 That's important to capture also, is not periods of
4 grid stress. It's periods of off-site power
5 vulnerability, I think is what you're trying to get
6 to.
7 MR. CAMERON: Okay. Thanks, Jennifer.
8 Thanks for that suggested language, and we'll go to
9 Steve again, which I think which Jennifer is saying is
10 consistent.
11 MR. ALEXANDER: Yes. As a matter of fact,
12 what she's saying is very consistent with the intent,
13 and perhaps we can, you know, craft some better
14 language, but the point is that we would like to know
15 what periods of time during the year, whether they're
16 related to particular seasonal conditions or not, do
17 you experience consistently for whatever institutional
18 or historical reasons a higher probability of problems
19 with off-site power? And we'd like to know that, and
20 then we're going to wonder if that needs to be
21 factored into routine risk assessments at certain
22 times of the year because you have some reasonable
23 expectation of the risk being higher at that
24 particular time for whatever reason.
25 MR. CAMERON: Okay, good. Thank you.

1 I think that was a positive discussion,
2 and let's not lose track of the long-term
3 recommendation that Alex Marion brought up at the
4 beginning of the discussion, but let's go for lunch.
5 I have about 25 to one. So if you can get
6 back here around 1:30, we'll be on time, but we won't
7 start exactly at 1:30.
8 (Whereupon,at 12:34 p.m., the meeting was
9 recessed for lunch.)
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1 AFTERNOON SESSION

2 (1:40 p.m.)

3 MR. CAMERON: Just as a point of order, I
4 think that was a good discussion on the risk insights
5 panel. We're going to start with our next panel on
6 Transmission System Operations.
7 If there are further issue related to the
8 risk insights panel, we'll pick those up tomorrow at
9 some point, but we have a distinguished panel, and we
10 wanted to get them on at the time we said we were
11 going to get them on, and we're going to go with
12 Ronaldo Jenkins from the Nuclear Regulatory Commission
13 who is going to go first. He's with at least at this
14 point Nuclear Reactor Regulation.
15 Okay, and then we're going to go to Susan
16 Court, who's the Director of the Office of Market
17 Oversight and Investigation at the Federal Energy
18 Regulatory Commission.
19 Next we're going to David Nevius, and he's
20 the Senior Vice President at the North American
21 Electric Reliability Council.
22 Then we're going to go to Frank Koza with
23 PJM, and we're going to finish up with Sam "Jimmy"
24 Erven from North Carolina, but with the National
25 Association of Regulatory Utility Commissioners.

1 And, again, we're going to run through the
2 panel, and then we'll give the panelists the courtesy
3 of questions or comments on what the other panelists
4 said, and then we'll open it all up to you.
5 So let's start with Ronaldo.
6 MR. JENKINS: My name is Ronaldo Jenkins.
7 I'm the Branch Chief of the Electrical Engineering
8 Branch in the Division of Engineering. I work for
9 Mike Mayfield.
10 Just a few remarks. I didn't want to take
11 up anymore time from the other panelists. The purpose
12 of this workshop is to hear from you, hear your
13 comments, any kind of feedback you might have, and
14 that's sort of why I was kind of holding back, wanted
15 to jump out of my seat on some of the questions that
16 were being asked this morning, but that would have
17 meant less time for you to make your comments.
18 So I'd just like to encourage you to kind
19 of let everything hang out, what you feel needs to be
20 changed, but in order to make any clarifying changes
21 to the GL, we do need specific comments, and so if
22 there is language that is confusing that might lead
23 you to an unintended consequence, please let us know
24 and we'll certainly factor that into our
25 deliberations.

1 Thank you.

2 MS. COURT: I wanted to make sure I had

3 all of the electronics down here correct.

4 Good afternoon, ladies and gentlemen. My

5 name is Susan Court, and I am, as indicated, the

6 Director of the Office of Market Oversight and

7 Investigation at the Federal Energy Regulatory

8 Commission, and for the purposes of this statement in

9 this presentation, I'm going to refer to the

10 Commission, my Commission, as the FERC to avoid any

11 confusion with your Commission, Ronaldo.

12 I've been a member of the FERC staff for

13 about 24 years, and have held a variety of positions.

14 Before becoming the OMOI Director a couple of months

15 ago, I served as Chief of Staff and had the honor of

16 signing the memorandum of agreement between the NRC

17 and the FERC. Accordingly, I'm very pleased to

18 participate today in this workshop on the proposed GL

19 on grid reliability.

20 At this time I'd like to introduce two of

21 my colleagues who will also be available to answer

22 questions. Mr. Bruce Poole, sitting in the front row,

23 is an engineer with the FERC's Division of Reliability

24 in the agency's Office of Energy Markets and

25 Reliability.

1 Ms. Demi Anas is an attorney with the
2 FERC's Division of Enforcement in my office, OMOI.
3 As you may know, the FERC is currently
4 engaged in crafting rules to create an electric
5 reliability organization or ERO and develop procedures
6 to establish, approve, and enforce electric
7 reliability standards.
8 This rulemaking, by the way, is mandated
9 by the Energy Policy Act of 2005, which we call around
10 the FERC "EPACT." We're very clever people, we people
11 at FERC, EPACT.
12 As a member of the FERC's Reliability
13 Division, Mr. Poole has been involved in that effort,
14 which is pending final agency action. Mr. Poole was
15 also very active in the FERC's efforts following the
16 2003 blackout, which in large part prompted the FERC's
17 involvement in reliability matters before the passage
18 of EPACT.
19 Ms. Anas was very instrumental in
20 developing the FERC's Standards of Conduct, applicable
21 to electric and natural gas companies subject to the
22 FERC's jurisdiction.
23 As it is our understanding that the
24 request to have the FERC participate in this workshop
25 was primarily sought because of the operation of those

1 standards and their impact on off-site power, I will
2 briefly describe the standards of conduct and the
3 provisions that the FERC has made with respect to
4 nuclear facilities.
5 In November 2003, the FERC issued a final
6 rule on the standards of conduct for transmission
7 providers. That's the title of the rule in an order
8 entitled Order No. 2004. So you'll hear these two
9 terms used interchangeably, Order No. 2004 or
10 standards of conduct.
11 The rules became effective on September
12 22nd, 2004, and the regulations are codified in Part
13 358 of Title 18 of the Code of Federal Regulations,
14 for all of the lawyers in the room. I know lawyers
15 like to know about those CFR things, right? Right.
16 In brief, the standards of conduct govern
17 the relationship between FERC jurisdictional natural
18 gas pipelines and electric public utilities, which are
19 referred to as transmission providers, and they're
20 marketing and energy affiliates.
21 Now, a very brief FERC 101, the FERC's
22 jurisdiction is over natural gas companies. The sale
23 for resale of natural gas in interstate commerce and
24 the transportation of natural gas in interstate
25 commerce and also the facilities, natural gas

1 facilities. We have a licensing or certificate
2 function with respect to natural gas companies.
3 The FERC's jurisdiction with respect to
4 electric utilities is over the sale for resale of
5 electric energy in interstate commerce, and over the
6 transmission of electric energy in interstate
7 commerce, and because of EPACT, we also have backstop
8 authority with respect to the siting of transmission
9 facilities.
10 Anyway, going back to the standards of
11 conduct again, standards of conduct apply to these
12 transmission providers. That's natural gas pipelines
13 and electric utilities and their marketing and energy
14 affiliates.
15 A marketing affiliate is a transmission
16 provider's energy sales unit, unless the unit engages
17 solely in what we would call a bundled retail sale.
18 Again, FERC's jurisdiction is over wholesale sales.
19 State commissions have jurisdiction, as Jimmy will
20 point out to you I'm sure, over retail sales.
21 An energy affiliate is an affiliate of a
22 transmission provider that engages in or is involved
23 in transmission transactions, manages or controls
24 transmission capacity of a transmission provider,
25 buys, sells, trades or administers natural gas or

1 electric energy or engages in financial transactions
2 relating to the sale or transmission of natural gas or
3 electric energy.
4 So generally speaking, the transmission
5 providers' affiliates, and there are some major
6 exceptions like local distribution companies that sell
7 at retail, natural gas at retail are not covered under
8 this definition of affiliate.
9 Now, the standards of conduct are designed
10 to prevent these transmission providers from granting
11 undue preference to their marketing or their energy
12 affiliates. They require the transmission provider,
13 one, to function independently from its marketing or
14 energy affiliates, treat all transmission customers
15 affiliated and nonaffiliated on a nondiscriminatory
16 basis, and, three, operate its transmission system in
17 a way that will not unfairly provide benefit to its
18 marketing or energy affiliates.
19 Our enabling statutes, by the way, the
20 FERC's major enabling statutes are the federal PAR Act
21 from 1935, and the Natural Gas Act from 1983, and
22 they're rather simple, straightforward statutes. They
23 basically say that companies can only charge just and
24 reasonable rates and may not discriminate or unduly
25 discriminate in the provision of their sales or their

1 transportation or transmission services.

2 So these rules really are grounded in

3 these fundamental principles, especially the

4 prohibition against undue discrimination that's found

5 in these 1930 depression era statutes.

6 The standards of conduct also require a

7 transmission provider to insure that employees of its

8 marketing or energy affiliates have access only to

9 information available to the transmission provider's

10 transmission customers, namely information posted on

11 the company's OASIS, or open access same time

12 information system.

13 The FERC requires electric transmission

14 providers to post on the OASIS, their OASIS, a variety

15 of information to give all users of the open access

16 transmission system access to the same information.

17 As relevant here, the FERC has adopted

18 several exceptions to the constraints on communication

19 between transmission providers and their marketing or

20 energy affiliates.

21 First, under emergency conditions, a

22 transmission provider may take whatever steps are

23 necessary to keep a system in operation. That's a

24 pretty simple, straightforward proposition. Under

25 emergency conditions, a transmission provider may take

1 whatever steps necessary to keep a system in
2 operation.
3 Thus, under the circumstances like those
4 experienced in August 2003 during the blackout, a
5 transmission provider would be permitted to engage in
6 any type of communication and to share any employees
7 needed to keep the system in operation.
8 Subsequently, the transmission provider
9 would be required to report to the FERC each emergency
10 that resulted from any deviation from the standards of
11 conduct.
12 Also, as a general matter, the FERC
13 permits a transmission provider to share with its
14 marketing or energy affiliates information necessary
15 to maintain the operation of the transmission system,
16 and this information is defined as information
17 necessary to operate and maintain the transmission
18 system on a day-to-day basis, but does not include
19 transmission or marketing information that would give
20 the transmission providers market or energy affiliates
21 undue preference over the nonaffiliated customers of
22 that company.
23 Of particular note here, the FERC has
24 explicitly stated -- now say that ten times fast --
25 the FERC has explicitly stated that this exception

1 covers nuclear plant operators.

2 During the rulemaking proceeding leading

3 up to the issuance of Order No. 2004, one commenter

4 expressed concern that nuclear plant operators

5 belonging to an energy affiliate of a transmission

6 provider would be prohibited from receiving

7 information they need to satisfy certain requirements

8 of the NRC's regulations.

9 The commenter also pointed out that

10 station blackout rules require that nuclear stations

11 have real time information on disturbances and

12 duration of power unavailability under Title 10 of the

13 CFR, specifically Section 5063.

14 In Order No. 2004, the FERC ruled that the

15 transmission provider would be provided to share this

16 type of information with its energy affiliates.

17 The FERC has also permitted transmission

18 providers to share with generation dispatch employees

19 information necessary to perform such dispatch

20 provided that such information does not include

21 specific information about individual third party

22 arrangements.

23 In sum, the FERC's standards of conduct

24 are intended to prevent the communication of

25 commercial information that would give a company's

1 affiliates an undue advantage in the marketplace.
2 They are not intended, definitely not intended, to
3 impede necessary communication between operators of
4 the transmission systems and nuclear power plant
5 generators.
6 On behalf of the FERC, Chairman Joseph
7 Kellaher and other members of the FERC, I thank you
8 for inviting my colleagues and me to participate in
9 this workshop, and of course, we'd be happy to answer
10 any of your questions.
11 MR. CAMERON: Thank you very much.
12 And if you could, please, Dave.
13 MR. NEVIUS: And if you could put my
14 slides up, please.
15 Thanks, again, to the NRC for inviting me
16 to be here. I apologize for my voice. I t's either a
17 change of life or I'm reaching puberty. I'm not sure
18 which it is.
19 This is an extremely important subject,
20 and one in which NEC has been involved for some time.
21 Certainly the August 2003 blackout which has been
22 mentioned here a number of times drew increased
23 attention to grid reliability, especially regarding
24 off-site power for nuclear power plants.
25 I'd like to highlight a few of the things

1 that NERC has done and is involved in today that are
2 relevant to this issue.
3 Next slide.
4 The four topics I'm just going to touch on
5 briefly and then hopefully open it up to you for
6 questions, what we're doing in our reliability
7 readiness audits and what we've learned from those;
8 some collaborative studies that we're conducting with
9 the NRC staff, the status of the off-site power
10 reliability standard that NERC is developing, and a
11 study that was done by one of our regions, the
12 Southeastern Electric Reliability Council on the
13 transmission nuclear interface.
14 Next slide.
15 On the reliability readiness audit, this
16 program was initiated in March of 2004 to address
17 specific issues raised by the August 2003 blackout.
18 In many respects, this program is similar to the INPO
19 evaluations program. The differences are that we will
20 publish or we do publish the results of these audits
21 on our Website.
22 To date we've conducted audits of well
23 over 100 regional reliability coordinators, RTOs, ISOs
24 and other transmission grid operators. Thirty-four of
25 these by my count have been systems and entities that

1 have nuclear units within their footprints.

2 Early on we added the transmission grid

3 nuclear power plant interface topic to our audit

4 questionnaires and to the on-site visit agenda. There

5 were some good practices that we've identified with

6 regard to this interface, and some areas for

7 improvement that we've also identified.

8 Some of the good practices, several

9 utilities and transmission operators have special EMS

10 alarms and displays that give a higher category of

11 importance to situations where post contingency

12 voltages at nuclear safety buses may fall below tech

13 spec limits.

14 Also, one utility in particular, which we

15 cited as an example of excellence, that's American

16 Electric Power, has a special nuclear power plant

17 voltage adequacy load flow program that they run every

18 30 minutes. The details of this are also on our

19 Website.

20 Some entities set more conservative system

21 voltage limits at the place where the nuclear plants

22 are connected to their system, and then lastly, a

23 number of utilities have rather specific interface

24 agreements which include individualized voltage

25 support guidelines.

1 One point that I didn't put on here that
2 I should have is that a number of these agreements
3 require regular coordination meetings, sometimes
4 weekly, at least monthly, between the transmission
5 grid operator and the nuclear plant operator.
6 Next slide.
7 Some of the things that we found that we
8 felt were in need of some improvement, and again,
9 these audits began in the spring of 2004. So some of
10 these issues have already been addressed, that is,
11 communication of nuclear power plant voltage
12 requirements to the transmission system operators.
13 So the operator of the grid knows what
14 those limits are. Also, more detailed modeling and
15 monitoring of the post trip voltages at critical buses
16 in the nuclear power plant using real time contingency
17 analysis or other similar analysis programs.
18 There are some examples. I think Frank
19 Koza will talk about one of them where there's some
20 more detailed modeling of the specific loads in a
21 power plant so that the grid operator can actually
22 determine when critical safety bus voltages may fall
23 below limits under various contingency conditions.
24 And then as Susan Court mentioned,
25 improved understanding of the code of conduct

1 exceptions for nuclear power plants. That was an
2 issue that we've heard about in a number of places,
3 and I'm glad that she was here today to clarify that.
4 All of these readiness audit reports are
5 posted on our public Website, www.nerc.com, pretty
6 simple.
7 Next slide.
8 I also signed a memorandum of agreement
9 with the NRC. The basic agreement was signed in
10 August of 2004, and then I signed four appendices in
11 June of 2005. One of those appendices is a
12 coordination plan for the exchange of operational
13 experience data and information. It describes how
14 NERC and NRC staffs will communicate and cooperate
15 regarding the assessment of grid performance data over
16 time to identify changes, emerging trends, potential
17 vulnerabilities, local problems, statistics,
18 probabilistic risk assessments, et cetera.
19 We're working with the NRC staff to
20 include the nuclear power plant operating parameters
21 in all regional and interregional study work and
22 collaborating on these technical assessments of grid
23 performance, and after the discussion just before
24 lunch, I think we do need to make sure that this work
25 looks very closely at how we count things.

1 There's lots of data, but we need to be
2 smart and intelligent about how things are counted and
3 categorized.
4 We're also looking to expand some of the
5 grid models to represent the nuclear power plants in
6 more detail, and Frank Koza will talk about this pilot
7 project at Susquehanna Nuclear.
8 The next slide.
9 One of the most important initiatives, I
10 think, that NERC has underway is developing a standard
11 on off-site power reliability. NERC was requested to
12 develop this standard by the Nuclear Energy
13 Institute's Grid Reliability Task Force because of
14 changes to grid operation brought about by industry
15 deregulation and restructuring and because of recent
16 operating events. Some of these have been touched on
17 earlier today and are covered in the INPO addendum to
18 SOER 99-1 and in the topical report TR-440.
19 The standard will address required
20 coordination between nuclear power plants and
21 transmission system operators to insure safe operation
22 and shutdown of nuclear plants. The standard will
23 have certain requirements that apply to nuclear
24 plants, to transmission owners and operators, to
25 transmission planners, reliability coordinators, et

1 cetera.

2 Next slide.

3 The interface requirements covered by this
4 standard cover off-site power supply to enable the
5 safe shutdown of the plant during an electric system
6 or a plant event and avoiding preventable challenges
7 to nuclear safety as a result of an electric system
8 disturbance, transient or condition.

9 Here's a list up here on the slide of some
10 of the things that the standard will cover, and I
11 emphasized at the bottom that once NERC becomes the
12 electric reliability organization, which we hope will
13 happen early next year or some time next year,
14 compliance with all of these standards, all of NERC
15 standards, including this one, will be mandatory.

16 We're fortunate today to have Terry
17 Crawley from Southern Company here. He is the
18 Chairman of the standard drafting team for this
19 standard, and when we get into questions, I'm going to
20 drag Terry up here so that he can answer all of
21 your -- he's hiding, but I'll drag him up here anyway.

22 The next slide.

23 The first draft of this standard is posted
24 right now for comment through January 17. Terry asked
25 me to encourage all of you to look at this standard.

1 You'll see the address on the Website. It's easy to
2 find if you get to the NERC Website.
3 It's incumbent upon all of you whether you
4 work in a nuclear plant or you're a grid operator,
5 even folks in the NRC. We welcome any and all
6 comments on this standard. I think the way it is
7 drafted it addresses many of the issues that were
8 brought out in this morning's discussion.
9 I should say that if things go as we
10 expect and we get through several drafts of this
11 standard and we have a ballot of the standard, we
12 would propose the effective date to be around July 1
13 of 2007.
14 The last point I want to make is a study
15 that was done by one of our regional counsels, the
16 SERC region. I noticed there are several folks from
17 that region here today both from the nuclear plant
18 side and the grid operating side.
19 SERC is one of eight NERC regional
20 liability counsel members, and they launched this
21 initiative in October of 2004 to investigate the
22 interface between grid operations and nuclear power
23 plant operations. It's significant because SERC
24 includes over 30 nuclear units within its footprint.
25 The study focused on interface practices, enhancing

1 safe and reliable operation of the plants and off-site
2 power supply, the unique aspects of nuclear power
3 plant operating requirements, and then to share
4 noteworthy practices within the region and with other
5 regions in four areas, which are listed here.
6 Last slide.
7 The white paper, which is somewhat
8 restricted distribution I understand right now, does
9 have a number of areas identified for additional
10 study. They are to investigate the interface with the
11 large RTOs and independent transmission operators and
12 independent transmission companies as opposed to the
13 individual utility transmission operators; to address
14 code of conduct issues regarding communications
15 between transmission operators and nuclear plants; to
16 look at standards for real time tools and model
17 validation; and finally, training and education for
18 improved communications between transmission operators
19 and nuclear plant operators.
20 And I'll conclude by saying I think the
21 word "communication" was used many, many times today
22 and it should be used many, many times as we go
23 forward. There is no substitute whatsoever for
24 learning what happens in the other person's work
25 environment.

1 Grid operators need to know what's going
2 on in a nuclear plant control room and nuclear plant
3 operators need to know what goes on in a system
4 operations control room. That would go a long way, a
5 long, long way to addressing many of the concerns and
6 issues that we're all here to solve.
7 Thank you very much.
8 MR. CAMERON: (Speaking from an unmiked
9 location.)
10 MR. KLECKLEY: Okay. Thank you very much,
11 Chip.
12 And I would also like to thank the NRC for
13 the opportunity to appear before you this afternoon.
14 I'm going to speak about voltage control
15 for the nuclear power plants in PJM. It's a topic
16 that is criss-crossed throughout the generic letter.
17 Our thoughts and comments about how PJM does it are
18 mandatory here.
19 I will say this at the top though. This
20 certainly isn't the only way to do things, and this
21 just happens to be the PJM way of doing it, and there
22 are certain other acceptable ways to conduct business.
23 The first slide, please.
24 Just a couple of introductory comments
25 about PJM. If you could just focus your attention on

1 that pie chart on the right side of the slide, in PJM
2 nuclear power is approximately 30 percent of the
3 energy in PJM. So nuclear power is an extremely
4 important portion of the PJM marketplace.
5 The next slide, please.
6 The next slide kind of indicates all of
7 the nuclear units in PJM. There are 31 separate
8 units, and I'm going to touch upon that a little bit
9 later.
10 The next slide, please.
11 I want to, I guess, pay a small tribute
12 here to the people within PJM who do most of the work,
13 and it's not necessarily PJM. We have a very active
14 group of the nuclear generation owners. That group
15 meets on a monthly basis. We have active
16 participation from all of our nuclear owners, and a
17 lot of the things and improvements that PJM has been
18 able to put in place have been at the encouragement
19 and support of our nuclear owners.
20 The process basically is the nuclear
21 owners work with the PJM staff and our operating
22 committee. Our operating committee is basically the
23 non-nuclear generators plus the transmission owners in
24 PJM.
25 Any kind of new requirement that the

1 nuclear generation owners would bring forward are
2 vetted through that committee structure, discussed
3 with all of the parties and then agreed to and then
4 entered into the PJM manuals.
5 Next slide, please.
6 Okay. This is basically our obligation to
7 the nuclear power plants with respect to voltage
8 control. We're to operate the system within limits,
9 and even if the nuclear power plant has more
10 restrictive limits, we're to operate to those limits
11 as well.
12 The tools we use, real time contingency
13 analysis, a real time contingency analysis application
14 is basically running 4,000 separate contingencies in
15 PJM and it runs about every minute.
16 Beyond that, we are reactively limited in
17 PJM, which means there's a finite amount of transfers
18 we can reliably handle going from west to east across
19 the system. Therefore, we have a second application
20 called transfer limit calculator that is running every
21 five minutes and basically calculating the maximum
22 amount of transfers we can handle from the west to
23 east perspective.
24 Now, beyond those tools, and Dave
25 mentioned in his talk we are I'll say peeling the

1 onion back one more layer with respect to the modeling
2 of the nuclear power plants. We're working with PPL,
3 Susquehanna, and what we're going to try to do there
4 is beyond the real time contingency analysis. We're
5 going to go deeper into the plan and basically model
6 the emergency buses at Susquehanna and for the purpose
7 there of running and making sure that we're able to
8 handle even post accident loads in a reliable manner.
9 Next slide please.
10 These two slides or this slide basically
11 summarizes the voltage standards in PJM. The one
12 that's in the upper left are really our baseline
13 voltage limits, and they apply to all facilities in
14 PJM.
15 The one in the lower right are basically
16 documents, our actions that we take for any kind of
17 voltage situation. So all of these things are well
18 documented, well understood, all published, all public
19 information that both the nuclear power plants, PJM,
20 and all of the market participants know about.
21 Next slide, please.
22 In one of our PJM manuals, that being
23 manual M3, transmission operations, and the link for
24 that is at the bottom of the page here, it outlines
25 the mitigation protocols that we have in place for

1 nuclear power plant voltage limits. Basically it's a
2 three-step process. There's a lot of communication,
3 and the communication goes from PJM to the
4 transmission owner who is connected to that plan, and
5 then out to the plan itself.
6 A lot of communication, a lot of
7 information being shared.
8 The second aspect of this procedure is
9 that we do respect the special needs of the nuclear
10 power plant to have the actual voltage information.
11 So to dovetail Susan's comments, we've made exceptions
12 here for the idea that we need to share additional
13 information to the nuclear power plants that we
14 ordinarily would not share with others.
15 And the final thing is taking action. We
16 were one generation out of its economic merit order.
17 If we are in a situation where we are at least
18 simulating a violation of the voltage limit, so we'll
19 do what we need to do in the economic dispatch to take
20 care of those things.
21 Next slide, please.
22 I do have one example here. This happens
23 to be the Exelon example. We have a number of combat
24 area nuclear power plants. This basically summarizes
25 the process that we go through right now with Exelon

1 to manage.

2 They have a series of higher voltage

3 requirements than the baseline that I showed you

4 earlier. Anyway, PJM builds the conditional

5 contingencies in our real time contingency analysis to

6 monitor post contingency voltage.

7 Then we were running, as I mentioned, we

8 were running this calculation about every minute. If

9 we determine that we'll have a simulated violation, we

10 will contact through the transmission owner a person

11 on the Exelon staff who's the nuclear duty officer.

12 This is an on-shift nuclear person who will have the

13 decision making authority.

14 Once that person is contacted and made

15 aware of the voltage situation, they can either

16 authorize us to run a generation or they can take

17 action at the nuclear power plant to mitigate the

18 problem, and down at the bottom side, if the NDO does

19 authorize generation, then PJM will put additional

20 generators on as necessary to mitigate that post

21 contingency voltage within limits.

22 And if the limit is violated, then Exelon

23 goes into an LCO until the post contingency voltage is

24 brought within limits. Like I say, that's an example

25 of the actual practice we're using for the Exelon

1 plants in the combat area.

2 Next slide, please.

3 Just a couple of words about our outage

4 coordination process. Maintenance risk assessments

5 are mentioned significantly in the generic letter. A

6 process in PJM is that the plan outages are submitted

7 many times almost a year ahead of time to PJM. A

8 consideration is made and PJM has the ability to, I

9 guess, accept the request of any kind of outage

10 request. I'm sorry. We can accept or reject any

11 outage request.

12 And then the real activity begins like one

13 to seven days from the start of the outage where a

14 repeating set of analyses are run to make sure that

15 given the configuration of the grid and the situation

16 with regard to economic dispatch, that we can still

17 accommodate that outage reliably.

18 And then on the outage start date a final

19 analysis is done right before the equipment is

20 switched out of service to insure that we can handle

21 that out age reliably. So there's a whole multiple

22 step process that goes into place to make sure that we

23 can accommodate nuclear outages reliably.

24 Next slide, please.

25 Now, I want to shift gears a little bit

1 here in the spirit of Ronaldo's comments about
2 providing feedback about the generic letter. I've got
3 a series of questions here, and the format of these is
4 the italicized part are the words out of the draft
5 generic letter, and then I posed some questions, and
6 I just want to mention that this comes from the
7 perspective of the grid person who doesn't necessarily
8 know the details of the intent, I'll say, of the
9 nuclear regulation, but like I say, I would just like
10 to offer these up as questions as I'll say an
11 uneducated grid person looks at the generic letter.
12 The first topic, degraded grid reliability
13 conditions, and I know in the generic letter there is
14 a definition provided of what that means, but that
15 definition, if you will, is kind of in nuclear terms.
16 So as I step back and look at that, the questions that
17 I have are kind of in the middle there.
18 Could a degraded grid reliability
19 condition be any kind of circuit breaker maintenance
20 in the substation? Could it be outages of any
21 adjacent transmission lines? Could it be any routine
22 maintenance on the protection systems? Could it be
23 any high load conditions?
24 I would submit to you that any one of
25 those activities in some fashion increases the risk

1 for the nuclear power plant. The question is
2 interpretation. You know, the intent of the generic
3 letter was to address things like that.
4 And my further question is and who decides
5 that. I believe the generic letter places that in the
6 hands of the licensees to decide, and my only question
7 there is the licensee may not be a good judge of the
8 grid risk, and I can tell you for sure that we aren't
9 a good judge of the nuclear power plant risks. It
10 gets back to kind of Dave's point. There has got to
11 be significant communication here.
12 And, I guess, my point here would be that
13 maybe there's some further definition of these points
14 that needs to be in the generic letter because
15 conceivably you could take somewhat extreme
16 interpretations of that term.
17 Next slide, please.
18 The next topic is about basically when to
19 do maintenance, and I guess it kind of puts on the
20 licensee the responsibility to potentially reschedule
21 maintenance based on degraded grid conditions.
22 I think in the earlier sessions this
23 morning we talked about -- and I don't want to get
24 into that discussion about whether there's more risk
25 in the summer or not -- but anyway, you could get to

1 the situation where -- and I'm going to jump to the
2 bottom one -- you would not do maintenance in a high
3 load scenario. That is, in the winter or the summer
4 when there's high peak loads, you would not do any
5 maintenance at all.
6 The flip side of that is -- and those of
7 you who are involved in the grid know this, I guess --
8 in the maintenance season in the spring and the fall
9 there is a lot of equipment out of service, a whole
10 lot of equipment, and I guess if you're looking at it
11 from a risk perspective, that's also a risk factor.
12 Is the grid degraded, so to speak, in that facilities
13 are out of service that you would not entertain doing
14 nuclear maintenance in those periods.
15 So you can do the math there. If you take
16 the spring and the fall and the winter and the summer
17 away, that doesn't give you much time left.
18 So I don't want to be, you know, trite
19 about that, but I mean, you do have to be -- there's
20 a consideration to think about the ability to do
21 maintenance and to do it with the minimal amount of
22 risk.
23 Next slide, please.
24 The next topic I want to just briefly talk
25 about is formal agreements. One could interpret the

1 words in the generic letter to assume a separate
2 agreement, if you will, between each nuclear power
3 plant and their transmission owner. All I would tell
4 you about that is in PJM what we have is like umbrella
5 agreements that each member of PJM signs, is legally
6 bound to, and establishes the requirements in our PJM
7 annual for compliance.
8 So I just would offer out to the staff
9 that hopefully you're open to that kind of an
10 agreement kind of scenario as opposed to either
11 bilateral or trilateral agreements between the nuclear
12 power plant owner and the transmission owner and
13 potentially the TSO.
14 Next slide, please.
15 The next topic has to do with the periodic
16 check-in. I know as was mentioned, I guess, from Dick
17 from -- I'm sorry. You mentioned that this morning,
18 whether there has to be a periodic check-in.
19 In reading the words, I was also concerned
20 about that in that it does seem to imply that the
21 nuclear power plant should be calling their
22 transmission system operator on a periodic basis to
23 make sure everything is okay, so to speak.
24 I just put the numbers up there. We have
25 31 plants. We have eight owners. We have 16

1 transmission owners. We really don't need to put a
2 call center in place for the transmission owners, and
3 as funny as that sounds, I just hope that exception
4 reporting in our minds would be the way to go here and
5 not, in essence, calling periodically to make sure
6 everything is okay, and I just hope that the NRC folks
7 are --
8 (Applause.)
9 MR. KLECKLEY: Thank you.
10 I hope they're in favor of that as a way
11 to go.
12 My last slide has to do with the
13 recommendations in Reg. Guide 1.155, and I guess it
14 talks about what I'll call local power sources that
15 could be put into play here in a restoration activity.
16 The point I wanted to make here was it's very
17 difficult, I guess, to guess or analyze every
18 conceivable restoration scenario. In a situation
19 where the nuclear power plant is located immediately
20 adjacent to some other kind of black start facility
21 that could be used in a restoration, I think that's
22 pretty easy to work with.
23 The thing is though and the point I want
24 to make was there are so many combinations of what
25 could be in service, out of service, available, not

1 available so that in the restoration scenario, it's
2 too simple to say that you're immediately adjacent
3 generators would be employed to facilitate your
4 restoration.
5 In PJM we already give deference in our
6 procedures in our manuals to the importance of
7 establishing feeds into the nuclear power plants.
8 They go basically to the top of the list, and I just
9 want to be cautionary about the idea of specific
10 generators being tied to certain restoration
11 scenarios.
12 I think this is way too complicated a
13 picture to deal with in that situation. If you look
14 at even the August '03 blackout, there were portions
15 of the system on the edges that were very strong and
16 could be immediately employed to start the restoration
17 procedure, and we just have to be careful about that.
18 I think a lot of the restoration
19 literature has been based on a total blackout in a
20 very wide area, and I think what we've seen most
21 recently is that there are portions of this system
22 that are strong around the areas that are blacked out
23 and can really accelerate the restoration activities
24 that way.
25 So my guidance here or my thought is not

1 to be necessarily so specific about how the
2 restoration would be conducted, except to say that we
3 want to give deference to the nuclear power plants in
4 the restoration scenario.
5 And with that I will conclude and
6 certainly be happy to answer any questions that you
7 have in the other period.
8 MR. CAMERON: Thank you, and I know we'll
9 be going back to those thoughts. (Speaking from an
10 unmiked location.)
11 MR. ERVEN: Thanks, Chip.
12 As has been said several times, my name is
13 Sam Erven or Jimmy Erven. I'm a member of the North
14 Carolina Utilities Commission. I also serve as
15 Chairman of the Committee on Electricity of the
16 National Association of Regulatory Utility
17 Commissioners and since everything has an acronym,
18 ours is NARUC.
19 In addition, I also served as chairman of
20 the nuclear issues and waste disposal subcommittee of
21 the NARUC electricity committee from late 2002 until
22 early last year.
23 I'm speaking today on behalf of NARUC and
24 do want to thank the NRC for the opportunity to come
25 today and be with you.

1 NARUC, for those of you who don't know, is
2 the national organization of the state commissions
3 responsible for economic and safety regulation over
4 the intrastate operations of regulated utilities. So
5 as Susan said, we do the intrastate retail regulation
6 in general. They do the interstate wholesale
7 regulation. It's not always easy sometimes to find
8 where the line is there, but those are sort of the
9 black letter law principles that we all follow.
10 NARUC's members have the obligation under
11 state law to insure the establishment and maintenance
12 of such energy utility services as may be required by
13 the public convenience and necessity, as well as
14 insuring that such services are provided at just and
15 reasonable rates.
16 Our members include the governmental
17 agencies in the 50 states, the District of Columbia,
18 Puerto Rico, and the Virgin Islands charged with
19 regulating rates, terms, and conditions of service
20 associated with the intrastate operations of electric,
21 natural gas, water, and telephone utilities. So we're
22 kind of generalists. We're not specialists like
23 virtually everybody else here is.
24 The statement that I'm going to give you
25 today is an update of one that was provided to the NRC

1 by my colleague Commissioner Burt Garvin of Wisconsin.
2 On that occasion he described a resolution for state
3 action on mandatory reliability standards, which NARUC
4 adopted on February 16, 2005.
5 That resolution encouraged state
6 commissions to consider making compliance with
7 existing NERC reliability standards mandatory under
8 state law. We adopted this resolution because at that
9 time, and for some considerable time before that,
10 Congress had not passed legislation authorizing the
11 development and enforcement of mandatory reliability
12 standards.
13 NARUC has consistently supported
14 legislation that would result in the implementation of
15 a mandatory reliability regime, given the interest
16 that all state commissions share in the preservation
17 of a reliable bulk power system.
18 As you know, the Energy Policy Act of 2005
19 -- and we call it EPACT, too -- was signed into law on
20 August 8, 2005. Section 215 of the Federal Power Act,
21 which was enacted as part of EPACT, provides for the
22 creation of the electric reliability organization that
23 both Susan and David referred to.
24 The ERO under this law would have the
25 authority to adopt and enforce mandatory reliability

1 standards. NARUC, as we've said a number of times,
2 applauds the adoption of this reliability provision,
3 and we have attempted to assist in its implementation
4 to the greatest extent possible.
5 On September 1, 2005, the FERC -- and I'm
6 going to call them "FERC" because that's just the way
7 I do it -- issued a notice of proposed rulemaking for
8 the purpose of developing rules governing the
9 operation and approval of an ERO as contemplated under
10 Federal Power Act Section 215. In the NOPR, the FERC
11 proposed regulations addressing a wide variety of
12 issues, such as the criteria that an entity must
13 satisfy to qualify as an ERO, the procedures that must
14 be followed in an enforcement action by the ERO and by
15 FERC.
16 The criteria under which the ERO may agree
17 to delegate authority to propose enforced reliability
18 standards to a regional entity in the manner in which
19 the ERO should be funded.
20 Prior to the issuance of the NOPR, NARUC
21 was glad to participate with certain other interested
22 parties in an attempt to try to work out some of these
23 issues in advance, and I think most people believe
24 that was a fairly useful preliminary process.
25 On October 7th of 2005, NARUC filed

1 comments addressing the issues raised in the
2 reliability NOPR. In our comments we urged the FERC
3 to recognize that the NERC currently develops minimum
4 national reliability standards through an open
5 stakeholder process; that there are differences in the
6 design of the bulk power system in different parts of
7 the country; that regional reliability organizations
8 currently implement the national standards promulgated
9 by NERC in a manner consistent with regional
10 conditions; and that the FERC should build on the
11 existing structure in implementing the new reliability
12 legislation.
13 Although NARUC recognized that existing
14 regional reliability organizations are going to have
15 to adopt and implement certain changes in their
16 operations in order to be eligible to receive
17 delegated authority from the ERO, we urge the FERC to
18 allow the existing regional reliability organizations
19 the opportunity to transform themselves into the
20 regional entities envisioned by the EPACT in order to
21 preserve the existing storehouse of regional
22 reliability information and to provide continuity to
23 the new organizations.
24 The logic behind our emphasis upon the
25 importance of preserving a significant role for

1 regional entities, I hope, is obvious. Historically
2 regional standards criteria and rules had gone beyond
3 the bare minimum level needed to prevent cascading
4 blackouts and have attempted to provide other
5 reliability requirements intended to insure that local
6 problems didn't develop into major ones as a result of
7 the intention.
8 The current allocation of responsibilities
9 recognizes that a national organization lacks the
10 detailed local knowledge of system events and
11 conditions necessary to effectively implement and
12 enforce reliability standards that exist at the
13 regional level.
14 Similarly, a national organization lacks
15 the regional knowledge of local system design,
16 demographics and requirements necessary for customized
17 regional reliability rules.
18 As a result, while NARUC fully supports
19 enforcement of the provisions that call for the
20 adoption and enforcement of minimum national
21 reliability standards, NARUC also believes that the
22 differences among regions necessitate a significant
23 role for regional entities and that FERC should
24 recognize this fact in the final rule that's adopted
25 in the reliability rulemaking.

1 Our participation in the reliability
2 rulemaking proceeding has not been limited, however,
3 to the filing of comments. On December 9, 2005, the
4 FERC held a technical conference that dealt with the
5 reliability issue, and we were privileged to be
6 permitted to participate in that proceeding. My
7 colleague, Commissioner Alan Freifeld of Maryland gave
8 a statement on behalf of NARUC at that time, and he
9 stated that the states have a significant role to play
10 in the maintenance of reliable electric service, and
11 pointed out the provision in EPACT that specifically
12 preserves the rights of states to act to insure the
13 safety, adequacy, and reliability of electric service
14 within the state's boundaries, as long as that action
15 is not inconsistent with the reliability standard
16 developed by the ERO and approved by FERC.
17 As a result, in our view at least,
18 responsibility for the maintenance of a reliable bulk
19 power system is shared among state, regional, and
20 federal and national authority.
21 We look forward to the adoption of the
22 FERC's reliability rules and hope we'll be able to
23 continue to participate constructively in the process
24 of implementing this very important piece of
25 legislation.

1 In our statement last year, we informed
2 you that there's a close relationship in many ways
3 between NARUC and NERC. For several years, a number
4 of our state commissions have actively participated in
5 the NERC standard development process. We have tried
6 to encourage more of that in recent years and adopted
7 a resolution that was approved by the NARUC Board in
8 July of last year that called on states to join the
9 NERC registered ballot body and to participate in the
10 development of and the casting of informed votes on
11 electric reliability standards applicable to the bulk
12 power system.
13 Since NARUC adopted that resolution, at
14 least two other state commissions have taken the steps
15 necessary to participate in NERC's standard
16 development processes. NARUC believes that state
17 participation in the development and approval of
18 reliability standards will and should continue in the
19 future.
20 At present NARUC and its members actively
21 participate in NERC in several ways. NARUC and
22 various states are active observers of NERC's
23 activities. NARUC and at least several individual
24 states are registered as voting members of NERC.
25 The states have two representatives on

1 NERC's standards authorization committee, which
2 develops reliability standards. States have two
3 representatives on NERC's compliance and certification
4 committee, which is the enforcement arm of NERC.
5 The states also have representatives on
6 such NERC standing committees as the planning
7 committee and the operating committee. State
8 regulators and staff also participate in regular NERC
9 briefings that are held by Webcast. Recent briefings
10 have focused on questions such as proposed changes to
11 NERC's reliability standards and industry compliance
12 with existing standards.
13 Finally the states have representatives on
14 the NERC stakeholder committee.
15 In addition to our activities within NERC,
16 we also participate in the activities of the North
17 American Electric Standards Board, which for those of
18 you that don't know what NAESB is, it's a body that
19 attempts to develop uniform business practices for
20 electric and gas industries.
21 Within NAESB NARUC has attempted to insure
22 that the standard business practices that are
23 developed by that organization don't undermine
24 reliable bulk power system operations.
25 Finally, as we indicated in April of last

1 year when Commissioner Garvin was here, the National
2 Regulatory Research Institute, which is affiliated
3 with NARUC, had performed a survey about individual
4 state actions to insure liability at the distribution
5 level. A written version of these remarks is, I
6 think, somewhere floating around the room and there's
7 a summary of the survey results that are available if
8 anybody is interested in looking at them.
9 Chip, that concludes my prepared remarks.
10 If we haven't totally anesthetized everybody by this
11 point, I'll be happy to answer any questions that
12 anybody may have.
13 MR. CAMERON: Okay. Thank you, Jimmy.
14 And thank all of you.
15 You just heard a lot of valuable
16 information about grid reliability, and it goes beyond
17 the immediate issue of discussion, which is the
18 generic letter, but we do have the experts, the
19 resources here. So I would just say take advantage of
20 that if you have questions about grid reliability
21 generally.
22 But we are here to discuss the generic
23 letter and Frank Koza was kind enough to give us some
24 specific examples of some language in the generic
25 letter that may be problematic. So don't lose that

1 focus.

2 I would give the panel an opportunity for

3 any questions between panelists, including any

4 comments that any of you might have on Frank Koza's

5 slides, and maybe just in anticipation, if we could

6 just put the last three or four slides from Frank

7 Koza's presentation up there in case we need them.

8 But, panelists, anything? Ronaldo, you

9 have something?

10 MR. JENKINS: Yes, I have a few questions.

11 Susan, I'd like to thank you for your

12 presentation on the standards of conduct. At the

13 February 2005 INPO, EPRI, NEI workshop in Atlanta

14 there was quite a bit of comments from the

15 participants basically say that, you know, FERC rules

16 prohibited us from sharing information, and I was just

17 going to follow that up with a question.

18 Is there anything with respect to the

19 generic letter that the FERC rules prohibit the

20 nuclear power plants from getting that information

21 from the transmission system operators?

22 MS. COURT: Actually I can't speak to the

23 generic letter itself because our participation, as

24 you may know, was relatively late, and so as far as

25 actually studying the generic letter, vis-a-vis our

1 specific requirements, I can't speak to that, and I
2 apologize for that. I don't think my colleagues can
3 either because I don't think we have really had the
4 opportunity to look at it from that perspective.
5 However, I don't know where they were
6 coming from, to tell you the truth. Because my
7 understanding from what the RECD has said about this,
8 there should be no impediment in communication between
9 the nuclear plant and their affiliates.
10 So maybe there was just a general
11 statement like that. It's hard to kind of address,
12 but the FERC specifically addressed that concern in
13 one of its iterations on those topic.
14 Order No. 2004 was not just a single
15 order. It was actually a combination of orders that
16 were issued over a year and a half period. So maybe
17 they missed that version. I don't know.
18 MR. JENKINS: Thank you for that
19 clarification.
20 MR. CAMERON: And Ronaldo, before you go
21 on, let me ask whether David or Frank has anything
22 that they want to add on on that issue.
23 Okay. Thank you very much, Susan.
24 MR. JENKINS: You had a slide up there
25 that basically indicated that standard would be

1 mandatory compliance. Is that mandatory for nuclear
2 power plants? And exactly how does that dovetail with
3 regulatory requirements?
4 MR. NEVIUS: Well, as the DRO if we
5 establish a standard which we submit to FERC and the
6 provincial regulators in Canada for their approval,
7 once that approval is given, the standard is
8 applicable to all of the NDs that are called out in
9 the standard.
10 In this particular case, the draft calls
11 for compliance with the standard by generation owners,
12 transmission order, operators, et cetera. So, yes, it
13 would apply to nuclear generator ownership and
14 operators.
15 MR. JENKINS: Is there any deference to
16 NRC requirements or do you consider them above and
17 beyond?
18 A similar question that you had this
19 morning about INPO's standards of conduct being
20 higher.
21 MR. NEVIUS: Yeah, I don't think there's
22 anything inconsistent. Terry, don't hide behind your
23 pad this time. There's nothing inconsistent in the
24 draft standard with NRC requirements as far as I can
25 tell. Do you?

1 MR. CRAWLEY: No. The intent is to
2 actually reinforce that so that mainly the primary
3 responsibility the nuclear power plant owner has in
4 this is, number one, to clearly communicate its
5 requirements to the transmission planners, operators,
6 and so forth so that they understand them. Okay?
7 As Dave mentioned, I think a lot of the
8 problems have been just communications or maybe lack
9 of understanding of communications because
10 communications were not concise, and of course, this
11 involves more than just written. You know, you can
12 have a requirement to have a written agreement, but
13 you can only put so much detail into that agreement.
14 So the standard is not intended to go to
15 that level of detail, but it's really to get the two
16 or three or four -- actually there are going to be
17 multiple parties as you well know now with the way the
18 deregulated industry is structured. So it's to bring
19 those parties together to make sure that those
20 requirements, whoever they apply to on the
21 transmission side, are clearly communicated
22 Now, obviously, the nuclear plant owner
23 has other responsibilities as well, such as related to
24 the maintenance rule as far as communicating that type
25 of information.

1 So we've tried to cover all of that within
2 the standard really, as you said, to dovetail the
3 regulatory requirements back into the transmission
4 side so that they get factored into and not overlooked
5 by the transmission planners and operators when
6 they're doing their thing.
7 So we'll take a second look at it, but I
8 don't see anything at this point.
9 MR. CAMERON: Okay.
10 MR. CRAWLEY: Anyone else who's involved
11 on the development of the standard, if you have any
12 thoughts on that, please speak up.
13 MR. CAMERON: Okay, and that's Terry
14 Crawley.
15 MR. CRAWLEY: Sorry. Terry Crawley. I'm
16 with Southern Company Generation, representing
17 Southern Nuclear here.
18 MR. CAMERON: Thank you, Terry.
19 MR. JENKINS: You'll be hearing from us
20 regarding our comments on the standard.
21 MR. NEVIUS: Ronaldo, one point because it
22 came up in discussion this morning. One of the
23 specific requirements placed by this standard on
24 transmission NDs is to inform nuclear plant entities
25 when the transmission entity loses the ability to

1 assess the operation of the transmission system
2 affecting the nuclear plant interface requirements.
3 And that was brought up specifically this
4 morning. So basically if Frank loses his eyes and
5 ears on what's going on in the system, he would be
6 obligated to let the nuclear plants know that he can
7 no longer tell what their post contingency voltages
8 would be, right?
9 MR. JENKINS: And, Frank, what would your
10 response then be?
11 MR. KOZA: Well, we've got two responses.
12 First, if we lose our EMS system, we have a backup EMS
13 and a back-up control center. So we would relocate
14 the operating staff for that backup control center,
15 fire up the backup EMS, and probably be in business
16 within like 30 minutes.
17 Now, within that 30 minute period, we also
18 have our transmission owners who run the same kind of
19 software that we do, can do those calculations, and we
20 would basically hand off to them those calculations
21 and make sure that they informed the nuclear power
22 plants until you're up and running again.
23 MR. JENKINS: Okay. One other question
24 for you, Frank. In terms of action levels, emergency
25 action levels that you outlined there, is the role in

1 blackouts or load shedding actions that will be taken
2 -- that's considered an off normal?
3 MR. KOZA: Well, I think actually July
4 27th would be a good example to just step through
5 briefly. July 27th we ended up calling a five percent
6 voltage reduction in Washington and Baltimore.
7 One thing we do have is we do have a
8 Website that publishes all of the emergency
9 procedures. So anybody, you know, the general public
10 can see all of that stuff.
11 We communicated heavily with both our
12 transmission owners and the generation owners on that
13 day about what we were facing in this area, and even
14 though we had a lot of capacity to the west of us, we
15 had difficulty delivering into Washington and
16 Baltimore.
17 So to me that's the more likely scenario
18 of an emergency situation. At no time were any of the
19 nuclear power plants in this area at any kind of risk.
20 We did at one time consider if the load continued to
21 increase, and if you'll remember that day I think it
22 was like 98 degrees here and so on, but basically
23 we're in a situation where the next step we would have
24 considered would have been a load shed, but we would
25 have done the load shed to protect the reliability of

1 the system.

2 MR. JENKINS: Okay. Thank you.

3 MR. CAMERON: Ronaldo, is that the extent

4 of your questions of the panelists?

5 MR. JENKINS: yes.

6 MR. CAMERON: Any of you want to talk to

7 any of the others before we go to the audience?

8 Susan.

9 MS. COURT: I don't want to talk, not that

10 I wouldn't want to talk to you gentlemen. I'm sure it

11 would be a very interesting conversation.

12 (Laughter.)

13 MS. COURT: The one thing I just thought

14 I'd mention because I can now mention it even as I

15 speak, the FERC is issuing a press release indicating

16 that it's going to consider the ERO rule at a special

17 meeting on February 2nd. So for timing for the ladies

18 and gentlemen in the audience, you might be interested

19 in that rule that Jimmy just described and also has

20 been mentioned by several of us here, will be

21 considered by the FERC on February 2nd.

22 MR. CAMERON: Okay. Thank you very much,

23 Susan.

24 Let me ask all of you. Our agenda called

25 for a break at 2:45. Of course, that was based on

1 coming back at 12:30. I think we're going to go on
2 for a while before we take a break if that's okay with
3 everybody.
4 And I know that some of our panelists have
5 planes, et cetera, et cetera. So let's try to take
6 advantage of them being here.
7 So I'll open it up to all of you. Let's
8 go to Mr. Thorson.
9 MR. THORSON: James Thorson from Detroit
10 Edison.
11 I have a question, I guess, for Frank.
12 It's related to my previous question, and that is, you
13 know, if I get a phone call from yourself saying,
14 "Gee, we've lost our RTCA," what kind of actions would
15 you expect the utility to have the capability of doing
16 in the event of that notification?
17 MR. KOZA: I can tell you the transmission
18 owners at PJM all have real time contingency analysis
19 and are doing virtually the same calculations that we
20 are. Obviously we're focused on the bulk power
21 system. They are focused on the lower voltage, but
22 I'm pretty confident all of them can duplicate the
23 post contingency voltage calculations at the nuclear
24 plants that are necessary.
25 MR. THORSON: So we're being required to

1 ask the next question, which is: what if they can't?
2 MR. KOZA: You mean if we lost both>
3 MR. THORSON: Yes, sir.
4 MR. KOZA: Well, I guess that's where you
5 go into your LCO and that kind of thing.
6 MR. CAMERON: Can I just check that
7 assumption that Mr. Thorson put out there when you
8 said we're being required to go beyond that? Can you
9 -- being required by what?
10 MR. THORSON: Well, if you look at I
11 believe it was two, "Charlie," but I don't have my
12 notes here, there seems to be a strong suggestion that
13 in the event of loss of the total RTCA, that the
14 utility is required to perform an operability
15 determination, and I guess I'm deeply struggling with
16 what we would do in that operability determination
17 because we do not have the capability to duplicate
18 your either regional or local RTCA.
19 MR. CAMERON: Is this your question about
20 operability versus risk? Ronaldo, can we?
21 MR. JENKINS: Well, I guess the main point
22 of that question is going back to essentially the
23 first question, which is that the first question says,
24 well, I have agreements. I have communication with my
25 transmission system operator who is acting for me to

1 basically make that operability determination for me.
2 They are saying that they are providing me
3 with off-site power, and that off-site power will meet
4 my needs.
5 Then if you run into the situation where
6 a tornado or some other catastrophic event takes them
7 out, then the nuclear plant is sitting there
8 operating, and the question is: well, what is the
9 change in status?
10 Now, you know, there is this discussion on
11 the real time contingency analysis versus anything
12 else. If you are using something else, then we would
13 like to know what that something else is, and I want
14 to stay away from trying to tell you what the answer
15 is or what we specifically would say, "Okay. You
16 should come back to us with this particular answer."
17 But there have been examples, for example,
18 Southern Cal Edison, where they use nomograms. They
19 have analyzed and basically developed an envelope in
20 which their plant operates within, and as long as they
21 stay within that envelope, then they're okay, and so
22 if in a situation that you lost your computers, then
23 we go as engineers back to our manual, more primitive
24 types of calculations that we use, that we rely on.
25 So that would probably be an example of something that

1 would be okay.

2 Does that answer your question?

3 MR. CAMERON: This is the issue, and we're

4 going to go here now. Obviously it's an appropriate

5 time. This is the issue that Mr. Thorson brought up

6 before, that there was a lot of murmuring on after we

7 heard the NRC response to it that's in the parking

8 lot. Let's keep going with this and see if we can

9 illuminate it a little bit more.

10 Yes, sir.

11 MR. JURY: Yeah, Keith Jury from Exelon.

12 The question on inoperability evaluation,

13 I mean, obviously we had a discussion very early this

14 morning that not all plants have an RTCA or analogous

15 system, and the generic letter does -- I agree with

16 Mr. Thorson -- it does imply that if you do an RTCA

17 and it does become unavailable, that there's an

18 expectation that you do an operability determination

19 which has very specific meaning to those of us at the

20 nuclear power plants.

21 What I just heard you say was that you

22 would go to some sort of a manual method to try and

23 determine what your voltage is. There's a huge

24 difference between an operability determination and

25 that impact in doing a manual evaluation with whatever

1 tools you have available for your voltage, and I think
2 that that definitely needs to be clarified in the
3 generic letter.
4 MR. CAMERON: If I could ask you, is there
5 any easy, simple language that you would recommend
6 that the NRC put in or is it more complicated?
7 MR. JURY: Well, I think it's more
8 complicated. I guess the question after I've heard
9 the full benefit of the discussion that the NRC is
10 asking is what will you do, if anything, if you lose
11 your RTCA, and I think that's a fair question.
12 I think to tie it to the operability of
13 off-site power even implicitly is not what I heard the
14 intent to be, and I think that earlier when you heard
15 the murmuring, I was one of the murmurers, and the
16 reason I murmured is because you're not going to
17 necessarily default to say we need to do an
18 operability evaluation on off-site power unless we've
19 had one of the by exception phone calls telling us
20 that we have a problem before they lost it.
21 MR. CAMERON: So you might change 2(f) to
22 just very simply say what would you do if you lost
23 your RTCA. All right. Okay.
24 Let's go right here. Yes, sir.
25 PARTICIPANT: Well, Keith pretty much

1 asked the same question, but I'll take it a step
2 further. You have 31 nuclear plants using the same
3 RTCA potentially, at least in our region potentially
4 five or six. If we enter into operability issues
5 associated with the loss of an RTCA and you've got six
6 plants that basically end up with both off-site power
7 sources being declared inoperable, I think that's the
8 last thing we want in a situation like that to have to
9 deal with it.
10 MR. CAMERON: Okay. Thank you.
11 We have some other comments here. This is
12 Phil, I think.
13 MR. BRADY: Yeah, Phil Brady, PPL-
14 Susquehanna.
15 I guess when plants were originally
16 licensed we didn't necessarily have these RTCAs. They
17 were licensed based on studies and analysis, and I
18 guess my position would be that if you ever got into
19 this type of position, you'd go back to your studies
20 and your analysis to confirm that your operation of
21 your system is still valid, and you're basically in a
22 stable environment.
23 MR. JENKINS: That's right.
24 MR. BRADY: And they haven't said that
25 they've lost the capability to monitor the grid.

1 They've just lost the capability to run the software
2 package. That's all we're talking about here, right?
3 MR. KOZA: That's correct, and there are
4 also -- we would go to off-line power studies, but you
5 know, everybody just needs to understand it's not
6 going to be as accurate as the real time information.
7 That's all.
8 MR. JENKINS: Right.
9 MR. CAMERON: Okay. Great. Let's hear
10 from one of the NRC staff. Tom.
11 MR. KOSHY: This is Thomas Koshy from
12 Electrical Engineering Branch, NRR.
13 What we are trying to find out, the higher
14 goal is when the transmission system operator tells
15 you that my program to predict what your off-site
16 power supply will be is not work; when you hear that
17 news, if you continue to believe unless I hear from
18 him everything is fine and I have my off-site power,
19 that's wrong. We shouldn't be reaching that
20 conclusion.
21 Now, Ronaldo just explained to one of the
22 cases where they have a nomogram which they have
23 analyzed and confidently determined that nomogram and
24 voltage indication is adequate to predict what the
25 off-site power will do given a plan a trip. So if you

1 can do an analysis and develop such a nomogram in
2 which you have confidence that if the plan trips you
3 will have the off-site power capable of supplying the
4 whole base and capacity, that is an alternate
5 approach.
6 We heard from PJM that they have their own
7 back-up and further downstream transmission system has
8 the same, similar program running in a more limited
9 area with its own backup. That would be very nice.
10 But in certain parts of the country when
11 you do not have such layers of protection, we need to
12 rely on some analysis. For example, I know about the
13 Palo Verde area. They have certain basic analysis
14 outside which they do not operate because they know in
15 the past years of experience they have done the worst
16 case analysis and said this guarantees sufficient off-
17 site power for our stations.
18 So there are cases when such analysis will
19 remain good, but why are we bringing up this, you
20 know, contingency analysis programming that took
21 place? Because based on the percent market
22 situations, your sale of power and which way the power
23 is flowing is decided probably the previous day or
24 maybe on the same day, depending on other contingency
25 conditions that rise us.

1 So can you predict all of those conditions
2 and the variations in the power flow given that you
3 have to assure that the off-site power remains
4 operable?
5 So in those cases where you cannot make
6 such predictions effectively, you may need to think of
7 having such a software so that you have a higher
8 confidence in making better predictions for your off-
9 site power.
10 I hope that explains.
11 MR. JENKINS: The issue is not whether we
12 asked the question or not. The requirement to insure
13 that systems, structures are operable is a truism.
14 That's the way we run plants. So the only question is
15 if I'm relying on a third party to provide me with
16 assurance they are totally competent, they've been
17 doing this for years. They are the experts. I don't
18 have the capability to do that.
19 Then when they tell me that they can no
20 longer do that for me, then responsibility then
21 resides with me to figure out what to do next, and so,
22 you know, that's pretty much where we are, and whether
23 it's a -- one of the things about the real time
24 contingency analysis program we've struggled with
25 within the staff is that it's very dependent on the

1 particular area you're located in. If you're in an
2 area of the country in which your power flows are
3 fairly predictable, you know pretty much whether it's
4 -- I hate to use the word "seasonal" here -- but
5 whether from time to time they change, but they're
6 certainly within a certain range, the staff has
7 accepted bounding types of analysis.
8 But the reality is that there are plenty
9 of places in the country where things are changing
10 quite a bit. I think Bill Raughley's presentation
11 showed the increase in the number of TLRs, which is an
12 indication of congestion on the system. So that's
13 just a reality of where we are.
14 So I think we can clarify the question if
15 need be, but that's about all I can say about that.
16 MR. CAMERON: Okay, and we did hear a
17 suggested clarification or a simplification on the
18 question.
19 Let's take a couple more points on this
20 and then see if there's another topic related to this
21 panel.
22 Did you want to say something, Mr.
23 Thorson?
24 MR. THORSON: Yeah, just one more, I
25 guess, clarification, but I think one possible

1 solution to this is to move this question out of the
2 operability area and into the risk area. If you
3 consider that situation where your RTCA is lost as an
4 area of increased risk, then a utility has the
5 capability of handling that within their maintenance
6 rule and they can make some relatively intelligent
7 decisions of what work they might do, what they
8 wouldn't do, what they would back out of, and I think
9 that gives you a greater, I guess, confidence level
10 that the direction of safety has been approached
11 rather than simply heading into an operability area.
12 So I guess that's just my two cents.
13 MR. CAMERON: Okay. Thank you for that
14 suggestion.
15 Now, we're still on Subquestion 2(f).
16 We're going to go to Alex and then we're going to go
17 to Paul Gill.
18 MR. MARION: Alex Marion, NEI.
19 I would recommend that those three, four
20 slides that Mr. Koza presented identifying points of
21 clarification from the transmission system operator be
22 considered as changes to the generic letter.
23 MR. CAMERON: Okay. Well, definitely I
24 think Mike Mayfield is shaking his head affirmatively
25 that they will be considered as suggested changes to

1 the generic letter at this point.

2 Paul, did you have something that you

3 wanted to add on this 2(f)?

4 MR. GILL: Yes. This is Paul again.

5 I want to follow up on this question about

6 2(f). I guess we all talk about if you lose your

7 RTCA. Certainly Ronaldo and Tom mentioned that you

8 may have other means to assess the off-site power

9 system.

10 Now, given that if you don't have any of

11 those means and you have no information, you need to

12 look at and see, you know, is that system operable or

13 not.

14 Now, it may or may not be. The question

15 is do you now -- the question is does the NPP conduct

16 an off-site power system operability determination.

17 Okay. Now, we heard from PJM that when

18 the RTCA program for Exelon predicts voltages are

19 going to be below the nuclear power plant requirement,

20 they go into an LCO. As a matter of fact, we have had

21 notification from Exelon plants they exactly did that

22 last year. As a matter of fact, three different

23 times.

24 Now, if you're in this --

25 MR. KOZA: But more often than not we've

1 run generators to boost the voltage.

2 MR. GILL: True, but I'm just saying that

3 they have entered the LCO. All they did was enter

4 their tech specs. Now, if you are sitting blind

5 because you don't have the RTCA and you don't have any

6 other means to predict what the voltages are going to

7 be, the question that we are asking is: do you enter

8 into determining your operability or not?

9 Okay. We're not saying that you declare

10 your system inoperable. We're saying what do you do.

11 Okay? The gist of the question is do you make an

12 operability determination.

13 Okay. Now, if you look at and make a

14 determination, gee, you know, voltages are not going

15 to be there, you enter your tech specs until the

16 problem is corrected.

17 MR. CAMERON: Okay. Let's take one more

18 comment on this. I think we've really been getting

19 some good comments on it, and we have some time

20 tomorrow to continue the discussion, but I just want

21 to make sure that we don't lose track of other issues.

22 Did you want to?

23 MR. GRANGER: Yeah, this is John Granger,

24 FPL, Florida Power & Light. I'm sorry.

25 In that scenario I just wanted to question

1 what if your diesel generator were out of service at
2 that point? Then you would enter a one-hour shutdown
3 LCO, which is definitely not where we want to go.
4 So I think that I agree with putting it in
5 the risk determination versus the operability.
6 MR. CAMERON: Okay. Thank you very much.
7 Okay. We can come back to this if we need
8 to. Now I just would -- I know that Jimmy Erven is
9 going to have to catch two trains, a bus, and whatever
10 to get to his airplane. Are there any questions or
11 comments for Jimmy?
12 Okay. Well, stay with us and just enjoy
13 yourself.
14 (Laughter.)
15 MR. ERVEN: I'm having a great time.
16 MR. CAMERON: All right, and we heard from
17 -- Alex, go ahead. There is one question for you.
18 MR. MARION: Alex Marion, NEI.
19 I received a couple calls over the past
20 couple of months from utilities who were expressing
21 concerns of actions being taken at a state level that
22 may go above and beyond what NERC is planning to
23 incorporate in certain standards or codes of practice.
24 Is there a protocol there or is there a priority where
25 one overrules the other?

1 Where would a utility go when that kind of
2 thing comes up?
3 MR. ERVEN: There's a provision that we
4 refer to in the reliability legislation as a state
5 savings price, which says, in effect, as I indicated
6 earlier, that a state can adopt reliability rules that
7 are not inconsistent with those approved by the ERO so
8 that, for example, if a state chooses to, it can adopt
9 a consistent reliability rule.
10 If someone to whom that rule is subject
11 believes that, in fact, the rule is not consistent
12 with the ERO's pronouncements, there is a provision
13 within which the person subject to that rule can apply
14 to FERC, if my memory is not failing me, for a
15 determination of consistency or inconsistency.
16 That's obviously a protection that's built
17 into the system to make sure that states don't put
18 operators in the position of choosing which of their
19 two sets of regulators they're going to choose to
20 comply with. That risk shouldn't exist on the bill.
21 MR. CAMERON: David, anything?
22 MR. NEVIUS: No, I think the specific
23 example, Alex, is New York State has some more --
24 MR. MARION: I wasn't going to mention
25 that.

1 MR. NEVIUS: Well, I will.

2 -- more specific standards, and they came

3 about after the 1977 blackout, and they consider under

4 certain higher risk situations, under thunderstorm

5 conditions that they'll operate somewhat more

6 conservatively.

7 Now, that's not inconsistent because it

8 certainly serves to enhance reliability and protect

9 reliability.

10 MR. ERVEN: And there actually is a

11 specific sentence in the state exception clause that

12 allows New York to do some things that other states

13 are not allowed to do. Sine I haven't read that in a

14 couple of months I can't tell you exactly what it is,

15 but there is a New York specific provision.

16 That commission has been very interested

17 in reliability rules, as Dave said, ever since the

18 blackout.

19 The other thing that is probably worth

20 noting is that many of the western state commissions

21 have been very actively involved in trying to persuade

22 FERC to allow the west to do certain things on an

23 interconnection-wide basis. I think what's going to

24 come of that effort really is up to Susan and her

25 colleagues, but that sort of tension is out there as

1 well.

2 MR. CAMERON: Okay. Thank you very much.

3 As we noted, the suggestions, the

4 questions that Frank Koza put before us are going to

5 be considered by the NRC, but let's see if any of you

6 have anything to say on these particular slides. Now,

7 I think this is the first slide, Frank, that you had

8 with --

9 MR. KOZA: It's the second one.

10 MR. CAMERON: It's the second one. Okay.

11 Here's the first one which basically

12 pointed out -- go back the other way. All right. One

13 more. Okay. Degredated -- what are degraded

14 reliability conditions? Could they be these four

15 things? Who decides?

16 Anybody want to add anything on that

17 particular slide to us? Tom, do you want to say?

18 MR. KOSHY: This is Thomas Koshy from

19 Electrical Branch.

20 Secure regular maintenance at the

21 substation. If that is a substation immediate to the

22 new glass stations, when you do maintenance on it,

23 does that increase the possibility of causing a plant

24 trip? Or if that increases the possibility of losing

25 off-site power, that does make a difference, and that

1 decision needs to come from the transmission people.
2 I can quote you examples if you look at
3 the operating history. Well, I think it was Beaver
4 Valley they were doing substation maintenance. They
5 lost both units and the off-site power.
6 So it depends on the maintenance and the
7 transmission company needs to characterize what is the
8 level of risk from that maintenance activity. If you
9 can fully isolate that break in maintenance in a way
10 that it will not cause the plant to trip or take the
11 off-site power, then you could consider that to be an
12 acceptable risk.
13 So essentially that is kind of our higher
14 goal when you look at how you need to be sensitive
15 about the maintenance activities that happen in the
16 switchyard.
17 The same case with the protection systems.
18 If you are testing the protective lane for the
19 incoming lines or outgoing lines and if you think
20 ripping those protective relay by actually injecting
21 a current in it can influence the logic in a way it
22 will take a ring bus out, that is significant and that
23 causes challenge to the plant trip as well as the off-
24 site power.
25 These are the type of assessments that

1 both parties need to make, and in the side of
2 transmission and switchyard, the transmission people
3 are more acute and experienced in that area. So that
4 input needs to come to the nuclear station from the
5 transmission site, whereas if it is a break that is
6 within the control of the nuclear stations, they need
7 to make that assessment.
8 So that is kind of the idea behind, you
9 know, having those discussions in general.
10 MR. CAMERON: Okay. Thank you.
11 MR. KOZA: If I could respond to that.
12 MR. CAMERON: Go ahead, Frank.
13 MR. KOZA: The reason I have those up
14 there, Tom, just so you understand, routine
15 maintenance of protection systems, relay technicians
16 go into substations all the time doing what seems to
17 be very innocuous maintenance activities, and I've
18 seen them take out. So I mean, is that to say we
19 never let the relay technicians in to do calibrations?
20 Because I would say to you any time
21 they're in that substation control room, they have the
22 potential to trip the plant and cause mayhem to start.
23 MR. CAMERON: Okay. Any other important
24 issues that someone wants to raise on this? And then
25 we'll go through the rest of them just to make sure

1 that we catalogue it.

2 Yes, sir.

3 MR. LUNSMIRE: Tim Lunsmire from the

4 Nuclear Management Company.

5 A caution on this one. With the grid,

6 since the grid operators or the TSOs don't really have

7 PRA assessments like, say, the nuclear plants, and

8 they don't necessarily understand how we do PRA

9 assessments, how can the grid operators like in our

10 area, mostly it's either they're within our voltage

11 limits, yes or no, or the grid is stable, yes or no.

12 When they do a particular activity on the grid, they

13 look at it to make sure that, yes, they can go with

14 the single contingency or even farther on, but they

15 don't have the same sense of risk as a nuclear plant

16 does where we go in the very detailed (a)(4)

17 evaluations to say the equipment is operable or

18 maintenance rule valuations for risk when we take that

19 evaluation into account.

20 When we ask the grid operator how to do

21 that, how does the staff like us to take that into

22 account? Because they don't have the same

23 philosophies as the nuclear plants do. So it's very

24 difficult to make an evaluation of grid operability or

25 grid risk of whatever the grid operator is doing

1 because they don't have the same perspective as we do,
2 as the nuclear plants.
3 MR. CAMERON: Okay. Thank you.
4 Frank looks like he's agreeing with that.
5 Ronaldo, do you want to say anything in regard to that
6 in terms of the generic letter?
7 MR. JENKINS: Well, I guess you get into
8 this issue of trying to know the entire universe and
9 respond to that in a single correspondence, and I
10 don't think the staff is looking for that. I think
11 that we're looking for known conditions, known
12 situations, whether they come from a PRA study,
13 whether they come from engineering studies that have
14 been done by the licensee to identify vulnerabilities.
15 The idea, and I believe this is coming
16 from the maintenance rule, is how do you factor that
17 into, you know, making your scheduling of taking major
18 pieces of equipment out of service. So Frank brings
19 up a good point in that you can certainly drill down
20 and you can find where a particular technician can
21 cause a problem, but that's certainly not the intent
22 of the generic letter to identify each and every
23 instance that could potentially come up.
24 MR. CAMERON: That seems to be -- we've
25 heard some similar discussion about some of the

1 anxieties associated with the questions where we've
2 heard the staff say that it's certainly not the
3 staff's intent to do such-and-such. Maybe -- and I
4 think you've heard the request for some clarification
5 -- maybe there needs to be some bounding language.
6 MR. JENKINS: You know, it's very site
7 specific, plant specific. There may have been PRA
8 studies that have been done that identify certain
9 circuit breakers that are particularly risk
10 significant, and obviously, you know, you want to
11 factor that into your overall risk management program.
12 But if you were talking about adjacent
13 transmission lines, many plants have several
14 transmission lines coming in and so that doesn't
15 necessarily rise to a level of a degraded grid
16 reliability conditions primarily because what you get
17 to go back to is what's the definition.
18 You're looking for can I get power to the
19 safety buses. If there's an activity that can
20 interfere with that and reasonably interfere with
21 that, then obviously that would be what we were
22 looking for.
23 MR. CAMERON: Okay. Thank you.
24 And I don't want to necessarily rush you
25 through these slides, but I just would like to see if

there are any important comments that people want to make on Frank's examples. This is the second issue that he focused on, and the elimination of when you're going to perform maintenance, I guess, for various reasons.

As Steve Alexander pointed out earlier, the issue is to identify any -- it doesn't matter if it's seasonal or what -- but to identify any potential problems with that, which may solve this issue. I don't know.

But does anybody else want to say anything about this particular slide? All right.

MR. COUTU: Tom Coutu with Exelon Nuclear.

One of the issues that we continually run into, and the previous slide implied a significant amount of integration and planning and scheduling of work both on the grid or on the transmission system and at the nuclear power plant. In terms of codes of conduct or standards of conduct, we have a pretty strict legal opinion on what information can be exchanged that is not public information.

And, Frank, maybe you can help me a little bit with this, but we appear to be very restricted with regards to disclosure of non-public information, including what's going to be out of service on the

1 grid at any particular point in time.

2 I heard today that that should not be an

3 issue.

4 MR. CAMERON: Susan, before you answer

5 that, can I just -- let me just get in response to

6 this slide Steve Alexander on briefly and then let's

7 go to you on that.

8 MR. ALEXANDER: Actually kind of as a

9 preamble to this slide, could we go back to his first

10 set of questions? Because they are really quite

11 closely related.

12 We talk about degraded grid reliability

13 conditions that would warrant the rescheduling of grid

14 risk sensitive maintenance activities, and that's kind

15 of related to the next one, and you asked what are

16 those degraded grid reliability conditions.

17 What we'd like to know is what you

18 consider degraded grid reliability conditions, how you

19 determine if they exist, and what do you do about it

20 if you find them. That's pretty much what it boils

21 down to.

22 Could they be those things? Absolutely.

23 Any or all of the above, and in fact, a reasonable

24 answer to the question would be here's what we think

25 are all the stuff that we deal with that could cause

1 grid reliability problems, and that could increase the
2 risk to the plant. Here's how we determine what they
3 are, what the severity is. Here's how we deal with
4 it. That's kind of what we want to know.
5 And so you suggest that those things could
6 be any of those, and the answer is, yeah, sure, all of
7 them possibly at any given time.
8 A very important thing at the bottom
9 there. Who decides? Licensee may not be a good judge
10 of grid risks in terms of what the possibility of
11 losing the proper voltage and frequency on the grid at
12 any given time, let's say, over the next few hours if
13 there's some condition that might be perceived to be
14 persisting.
15 And the TSO may not have an idea of what
16 those risks are specifically to the plant and then how
17 the subsequent trip of the plant would affect them.
18 So the answer who decides is they both do
19 by talking to one another, and that's why we ask about
20 agreements between the two, and some of the answers
21 that you've suggested are in a general way the kind of
22 stuff that we want to find out about. We're getting
23 an opportunity to get the answers to some of our
24 questions from you today.
25 We'd like to hear from everybody on the

1 same subject.

2 Can we go to the next one please?

3 If the grid reliability evaluation,

4 however you do it, but the point is we think that you

5 should do it, indicate that degraded grid reliability

6 may exist during maintenance activities, yeah, I admit

7 it. We think you should probably consider

8 rescheduling things.

9 We certainly don't expect you not to do

10 maintenance at all. That would be ridiculous, and

11 maybe this was meant, you know, somewhat in a -- but

12 we hope that --

13 MR. KOZA: I was going to an extreme

14 there, no question.

15 MR. ALEXANDER: Yeah.

16 MR. KOZA: I didn't want to get to the

17 point we were doing all maintenance at 4:00 a.m. on

18 Easter Sunday. That's all.

19 MR. ALEXANDER: And your point is?

20 (Laughter.)

21 MR. KOZA: It's a risky time.

22 MR. ALEXANDER: It's a risky time.

23 Well, what we want to know is are you

24 looking at the risks of those conditions, and are you

25 deciding, you know, making conscious decisions about

1 rescheduling maintenance if it looks like it's a
2 prudent thing to do?
3 We don't expect you to say, "Well, it's
4 risky, you know, from January 1st through December
5 31st. Therefore we're not going to do any
6 maintenance." Obviously we realize that, but we think
7 people should pick and choose intelligently their
8 maintenance windows and what kinds of maintenance they
9 do to minimize the risk.
10 MR. CAMERON: Okay. Thank you very much,
11 Steve.
12 And, Susan, you heard the gentleman's
13 question. Do you want to talk to that?
14 MS. COURT: Sure. I didn't want to give
15 the impression that you get a free pass if you're a
16 nuclear facility. There are no free passes here.
17 What I talked about and mentioned were the
18 two major exceptions to the general prohibition
19 against sharing information between and among
20 affiliates, first, in an emergency situation, and I
21 wanted to emphasize and I do emphasize that there's
22 nothing in the Commission's rules, there's nothing in
23 the Commission's intentions that its standards of
24 conduct rules would allow any impediment to a nuclear
25 facility getting off-site power in an emergency

1 situation. Absolutely not.

2 And then the second is the general

3 exception regarding the sharing of information to

4 maintain the operation of the transmission system, and

5 the Commission has specifically spoken to the

6 applicability of that exception to sharing of

7 information between transmission providers and nuclear

8 facilities saying it does apply.

9 That said, I am sure that the legal memo

10 is very careful to point out all the other types of

11 requirements that Order No. 2004 lays out. For

12 example, the functional separation.

13 So there are a lot of aspects of the

14 standards of conduct that I haven't addressed today,

15 and because it was beyond the scope of this particular

16 topic.

17 So the main point is that for general

18 operation and for emergency situations there are

19 exceptions to the general prohibition against sharing

20 information.

21 Order No. 2004, the FERC's standards of

22 conduct are intended to insure in a commercial sense,

23 in a marketplace that affiliates of transmission

24 providers do not get an undue advantage. The

25 intention, the purpose behind those rules is not to

1 impede operations. It's really an economic set of
2 regulations or a set of economic regulations, not
3 physical regulations.
4 So, again, I don't want to question or I
5 wouldn't question the legal memo that a company has
6 gotten because I'm sure it's on a much wider range of
7 topics.
8 And two other things I'd like to mention.
9 The Commission recently, I guess, at the end of the
10 year posted, the FERC posted on its Web page a whole
11 package of enforcement matters for the general public
12 and the industry's information, and one part of that
13 package is a list of frequently asked questions about
14 the standards of conduct. So I just set that out for
15 your information.
16 Also, recently the FERC issued an order
17 which sets up a process where a company can seek
18 information as to whether or not the Commission would
19 institute enforcement action under certain
20 circumstances. This is a no action letter process
21 which other agencies, other federal agencies have
22 used, and the FERC has just instituted that no action
23 letter.
24 So if there really is a question in your
25 mind, again, assuming we're not talking about an

1 emergency, assuming that we're not talking about the
2 average type of operational information, a company can
3 always seek that type of advice as well.
4 MR. CAMERON: Thank you very much, Susan.
5 On this issue about what's the NRC vision
6 of agreements, Ronaldo, let me ask you at this point.
7 What's your take on Frank's questions on this in terms
8 of what a licensee is expected to provide us in
9 response to that question in the generic letter?
10 MR. JENKINS: We have been involved with
11 the whole topic of grid reliability ever since the
12 western grid disturbance in 1996, and you know, from
13 our information visits to transmission system
14 operators, NERC, FERC, we have view that anything is
15 better than nothing.
16 And certainly the formal agreements
17 provides a structure by which information can be
18 exchanged. Now, we don't have a particular vision.
19 I guess that's the answer to your question, nor do we
20 have any restrictions or views that there's a
21 limitation on agreements.
22 The idea is that a third party has
23 responsibility. You've delegated responsibility
24 implicitly to that third party to assure off-site
25 power operability. From our view, you need to have

1 analysis or you do some kind of post trip evaluation
2 of the models that are being used, but in any case the
3 only way that we know of assuring off-site power in
4 this type of environment is by an analysis.
5 And so the third party has to make that
6 call. So obviously communication, as David Nevius
7 mentioned, is the key and it's important to have that.
8 And so we're in a fact finding mode in terms of this
9 generic letter. We're trying to obtain information.
10 MR. CAMERON: Okay.
11 MR. JENKINS: One other thing. During the
12 northeastern power outage August 2003, I had just come
13 out of a briefing of Commissioner Merrifield who was
14 the Acting Chairman at the time, and coming out of
15 that briefing, we found out that the event was
16 occurring.
17 And so going to our NRC incident response
18 center and you go in there and you say, "Well, what in
19 the heck is going on? What is it, that we have a
20 number of plants here that experienced loss of off-
21 site power?"
22 So at that particular instant in time we
23 did not know whether this was being driven by an
24 adversary or whether or not we were dealing with a
25 natural phenomenon or whatever. The main thing we

1 were looking for was information, and I guess I would
2 pose the question that assuming that we get through
3 the clarification part of this generic letter, and
4 everyone here is totally happy with the final product,
5 suppose that generic letter information had been
6 available prior to August 2003 and the staff had the
7 responses back and we had information profiles on
8 licensees so that when that event occurred, we would
9 be able to know, hey, this is what should be happening
10 right now.
11 I think we would have been in a much
12 better shape to respond to that event.
13 MR. CAMERON: Okay, and we're going to
14 take two more comments on this particular issue.
15 Again, just from a facilitator's observation, it
16 seems like there's an anxiety among people in the
17 industry that there should be a correct answer to
18 these questions, and what I keep hearing from the NRC
19 staff is, "Give us the best information you can on
20 this," that there's not necessarily a, quote, correct,
21 unquote, answer.
22 But I think we all realize there's always
23 a fear of what the regulator is going to do.
24 But at any rate, I'm going to go right
25 back here and then come up to you. Okay. Yes, sir.

1 MR. NICELY: Jerry Nicely, TVA Nuclear.
2 Part of the question here, you have
3 "promptly notify," and also question one, alpha is
4 what's the time period for the notification.
5 I know the people running real time state
6 estimator systems, I notice the PJM guy on one of his
7 slides indicated that they had a time period between,
8 I think, 15 and 30 minutes, if I saw the slide
9 correctly, but I guess I'm assuming that it's
10 acceptable. You know, should you calculate that
11 should I have a trip of my nuclear unit and my voltage
12 just may not be adequate, that you may want to run the
13 eight minute cycle one more time to see if the
14 condition cleared or possibly take action to try to
15 alleviate it before calling the nuclear plant and
16 shaking their day up.
17 I guess I just sort of want some opinion
18 both from the staff and maybe what PJM is doing. You
19 know, is it reasonable to allow the transmission
20 operator some period of time to try to alleviate the
21 situation before notifying the nuclear power, unless
22 it's an actual degradation that's happening right
23 then?
24 MR. CAMERON: Frank, do you have anything
25 to say on that?

1 MR. KOZA: Just that the way we do it is
2 we have up to 30 minutes to fix it. If we can't fix
3 it, we'll put generators on. We will do whatever we
4 have to do to fix it.
5 MR. CAMERON: Okay. Let's hear from Tom,
6 NRC staff, and then I want to ask you whether you want
7 to take a break for 15 minutes and then come back and
8 finish with the panel or whether you just want to run
9 straight through and try to adjourn by our four
10 o'clock adjournment time. It's a question for you.
11 Let's hear from Tom first.
12 MR. KOSHY: Could you put that previous
13 page on?
14 The question was individual bilateral
15 agreements between PJM and each nuclear power plant,
16 bilateral with PJM.
17 Let me kind of clarify to you what is the
18 higher goal. The higher goal is that the transmission
19 people clearly knows what the voltage requirement is
20 for each nuclear station. Speaking from operating
21 experience, one developed unit station replaces their
22 service water pumps in an outage. Once they came back
23 on line, they found out that the voltage set points
24 they have is not sufficient because the motors they
25 replaced with are of higher horsepower and it started

1 creating an under voltage such that the alternate
2 source brought under voltage on that condition and
3 then jumped back and both units tripped.
4 This is about ten-plus years ago. I'm
5 just giving an illustration to explain my point
6 because it is very important that the transmission
7 people remain continuously aware of what the plant
8 changes are that influence the acquired voltage for
9 the particular station.
10 So we are not picky on how you make your
11 agreements through a higher corporate level or a lower
12 level so long as this intention is served, so that you
13 have a continuing knowledge of what the exact voltage
14 requirements are.
15 When the plant trips, 1,000-plus megawatts
16 of generation switches to 15 megawatts of load, and
17 when it changes like that, if you have capability to
18 supply only the safety system loads, you cannot do a
19 normal shutdown. You are going to increase the
20 thermal expansion on the plant.
21 So you need to look in and see if you can
22 make that available and the transmission people are
23 clearly aware of the power demand when you actually
24 stopped generating.
25 And you need to revisit that issue

1 especially when you make major modifications to the
2 plant on service water pumps, on those large pumps
3 that are circulating water pumps, and fully aware of
4 that situation so that they can respond to the plant
5 need, and that is the higher goal we are trying to
6 serve.
7 And this is the question through which we
8 are hoping that we can put a strong reminder in the
9 industry to pursue towards a continuous update and a
10 clear understanding on both sides what the expectation
11 is.
12 MR. CAMERON: Thank you, Tom. I'm glad
13 you're here to remind us of what the higher goal is on
14 these, and I think it very useful actually for people
15 to understand that.
16 Can I get a sense of we don't want to keep
17 you here all day, but obviously if we take a break
18 now, I think that we probably have a half hour more of
19 discussion on this particular issue. Do you want to
20 just march through till four or do you want to --
21 PARTICIPANTS: (Speaking from unmiked
22 locations.)
23 MR. CAMERON: That's why I should never
24 ask those questions.
25 (Laughter.)

1 MR. CAMERON: Yeah. I'll tell you what.
2 How many for a break now?
3 (Show of hands.)
4 MR. CAMERON: Okay. I guess you can take
5 one.
6 (Laughter.)
7 MR. CAMERON: But okay. Let's try to go
8 through -- I'm sorry. Being facetious, but if you
9 need to go out, just people do that and let's take the
10 next half hour and continue to explore, and then we'll
11 see if we can go.
12 Do you want to do something before you
13 take a break? All right.
14 MR. REIMERS: My name is Greg Reimers.
15 I'm with Pacific Gas and Electric, Diablo Canyon.
16 And I guess what I clearly heard now is
17 the NRC acknowledges that it will be the transmission
18 operator making operability calls for off-site power
19 because if they predict voltage is going to be too
20 low, we're inoperable. We and our LCOs, and I guess
21 my question is, you know, the nuclear power plant
22 operator seems like the passthrough for NRC
23 requirements on the transmission operator with the
24 higher goal in mind wouldn't it be more efficient
25 since the NERC rules or proposed standards -- the

1 comment period closes at the end of the month for
2 nuclear off-site power issues from the NERC side of
3 the fence. Why not wait until those rules are done
4 and see what the transmission operators are really
5 going to have to do?
6 MR. CAMERON: Ronaldo, I'm going to go to
7 you on this one, and correct me if I'm wrong. The
8 generic letter is asking for information about certain
9 things.
10 MR. JENKINS: Correct.
11 MR. CAMERON: It's not saying that someone
12 should do this or someone should do that.
13 MR. JENKINS: Right.
14 MR. CAMERON: Okay. Is that --
15 MR. JENKINS: That's correct. That's
16 correct.
17 MR. CAMERON: Okay. Do you want to say
18 anything else in response to this gentleman's comment
19 or question?
20 MR. JENKINS: Well, I think that over the
21 years we have -- the staff has been involved with off-
22 site power issues almost going back in the licensing
23 period, and whenever off-site power issues have come
24 up, we have had licensees with their transmission
25 system operators sitting in the same room.

1 I don't recall a single instance in which
2 the transmission system operator was off somewhere
3 else and the licensee is doing something entirely
4 different with the NRC.
5 A case in point was Diablo Canyon. When
6 Diablo Canyon as part of the California deregulation,
7 there was the selling of Laurel Bay unit. The Diablo
8 Canyon came in, and they came in with their
9 transmission system organization, and they explained
10 to us what they would be doing now that the Laurel Bay
11 plant, which is identified in their FSAR as one of the
12 units that needed to run in order to maintain proper
13 voltage at Diablo Canyon.
14 They came in and explained to us what
15 modifications they were going to make in order to
16 insure that their plant would continue to operate at
17 adequate voltages. Okay?
18 So basically, all of the generic letter is
19 about that. It's about insuring that adequate power
20 is provided to safety buses, and of course you know
21 the times as spelled out in the technical
22 specifications limiting conditions for operations,
23 when that should be.
24 So you know, the NRC is not interested in
25 regulating any transmission system operators or

1 owners. I believe that David Nevius and then Frank
2 Koza would be very upset if we were trying to impose
3 any requirements on their organizations.
4 However, there is a responsibility on the
5 part of the nuclear power plant licensee to insure
6 that off-site power is operable during periods of
7 operation called for under the technical
8 specifications.
9 So I hope that answers your question.
10 MR. CAMERON: Okay. Thanks, Ronaldo.
11 We're going to go to this gentleman here.
12 MR. BONNER: John Bonner, Entergy Nuclear,
13 Northeast.
14 A follow-up question on the FERC Order
15 2004. You talk about the sharing of transmission
16 information with affiliate generators. Is that also
17 part of merchant generators?
18 MS. COURT: Yes, yes. It really just
19 depends on whether or not a particular company meets
20 the definition in the rules. So first of all you have
21 to start off with what's an affiliate, and that
22 involves a question of control.
23 So if a company, an enterprise is
24 affiliated with a transmission provider as "affiliate"
25 is defined and performs certain types of functions or

1 is not otherwise accepted from the rule, then yes.
2 So sometimes it's hard to answer that
3 question generally because there might be
4 circumstances, again, whether or not there's just a
5 minimal amount of control that might trigger one of
6 the exceptions to the rule, but it's possible. Let's
7 put it that way.
8 MR. BONNER: So the intent is that it
9 would apply to affiliates or from generators owned by
10 a transmission company as well as generators that have
11 no relationship to the transmission company other than
12 they utilize their transmission --
13 MS. COURT: No. That's not an affiliate
14 then. Remember this whole rule, the standards of
15 conduct deals with relationships between a
16 transmission provider and its affiliates. So a
17 merchant generator that is not affiliated with the
18 transmission provider doesn't trigger the rule. That's
19 just a customer on the system. It's not an affiliate
20 of the transmission provider.
21 So remember the purpose of the rule is to
22 insure that the company, the utility that is
23 transmitting the energy is not giving its affiliate an
24 undue advantage by giving it information ahead of time
25 or information that's not available to everybody else

1 who also wants service on the system. So it has got
2 a fairly simple, straightforward purpose.
3 MR. CAMERON: Okay.
4 MR. BONNER: Can I do a follow-up to that?
5 MR. CAMERON: Okay. Do a quick follow-up.
6 MR. BONNER: So if a generator isn't an
7 affiliate of the transmission company, it's all right
8 for that transmission company to provide information
9 to the merchant generator that's not also available to
10 other generators in the area?
11 MS. COURT: Well, remember there's a
12 general prohibition in FERC's rules which come
13 directly from the statutes that provides that a
14 company has got to act in a not unduly discriminatory
15 fashion vis-a-vis everyone.
16 In other words, if a company is giving out
17 information that is going to, even though there's not
18 an affiliation, it still has to treat everybody
19 fairly. So there's an overall prohibition against
20 undue discrimination.
21 So if a transmission provider is going to
22 give information in the marketplace selectively and by
23 doing so is going to discriminate, then the companies
24 that are discriminated against might have a fair claim
25 against that transmission provider.

1 But that goes to the overall statute.
2 That goes back to 1938, which says that a public
3 utility may not discriminate unduly in the
4 marketplace.
5 MR. CAMERON: And, John, you may want to
6 talk off-line with Susan or Susan's staff if you have
7 some more specifics.
8 MS. COURT: Yeah, if there's a specific.
9 Again, sometimes because of the control issue and
10 things of that sort, just dealing with these questions
11 in a vacuum is difficult.
12 MR. CAMERON: Okay. Thank you, Susan.
13 We have something else from Steve
14 Alexander of the NRR staff.
15 MR. ALEXANDER: Thank you. Still, I hope.
16 I guess I've heard a general kind of
17 concern here that we're expecting that nuclear utility
18 plant operators to be able to have a free exchange of
19 information that's necessary to safely operate the
20 plant with their transmission system operators, and
21 I've noticed a couple of times you've used the term
22 "under emergency conditions."
23 And I guess I have to ask the question two
24 ways. Is there anything that you've heard here in
25 terms of the kinds of information that we would like

1 to have licensees be able to get from the TSOs and the
2 kinds of information that the TSOs would like to get
3 from the licensees of nuclear power plants that would
4 run afoul of your rule, and does the exception allow
5 them to do that whenever they deem it necessary for
6 safe operation of the plant, whether there's an
7 emergency per se or not?
8 Because a lot of the stuff that we have to
9 do is planning for contingencies. What happens if
10 there is an emergency? There may be no emergency, but
11 there is still some risk because your ability to cope
12 with an emergency may be reduced.
13 So if there's anything, and I would also
14 say that perhaps in the near future when you have a
15 chance to review the generic letter in general we
16 would need to know if there's anything in there where
17 the utility could get in a bind in trying to serve two
18 masters. There's no way that we ant that in any way
19 to be able to compromise their to get all the
20 information they need to operate safely.
21 MS. COURT: Well, I can assure you that
22 the FERC does not want the business in the utilities
23 to be serving two masters to a point where that's
24 going to cause a problem.
25 Obviously you serve two masters. You

1 actually probably serve 100 masters with all of the
2 other federal agencies and state agencies out there
3 that you have to address.
4 But in any event, when I mentioned
5 emergency, what I was laying out was that there's a
6 specific exception in the rules for emergency
7 situations, and so when I referred to emergency
8 search, that's what I was talking about, a specific
9 exception.
10 With a subsequent follow-up, in other
11 words, a requirement that the utility then provide the
12 information after the fact so that information sharing
13 that would generally be prohibited, otherwise be
14 prohibited could take place in an emergency situation
15 with notification to the agency after the fact.
16 The other exception was the generally
17 applicable exception for day-to-day operation. That
18 type of information can be shared. As I mentioned,
19 the rule's purpose is geared to prevent the sharing
20 information that's going to have a commercial impact.
21 That's what it's all about, and so that's why the
22 Commission made the exception for the day-to-day
23 operations.
24 The staff is very amenable to answering
25 questions. That's why we created this frequently

1 asked questions part of our Web site. So if a member
2 of the industry has a specific question, we'd be more
3 than happy to. We have a hot line or you can call the
4 enforcement staff or you can call me, and we will try
5 to provide an answer to your specific question.
6 Now, as far as have we heard anything
7 today that would be problematic? I have -- I don't
8 know, Demi. Have you heard anything that would be
9 problematic?
10 MR. CAMERON: Okay. We're going to go to
11 Demi.
12 MS. COURT: This is Ms. Demi Anas, who has
13 worked very closely on the development of these rules.
14 MS. ANAS: And like someone else, I have
15 a frog in my throat today. So I apologize.
16 I think the key thing that we haven't
17 really focused on -- we've talked about the sharing of
18 information -- is that we allow the sharing of that
19 information, but the folks that receive that
20 information are prohibited from passing it along to
21 the folks who were involved in the commercial aspects
22 of the business. We've labeled that as the no conduit
23 rule.
24 So I think to sort of show the whole
25 picture is, you know, we recognize that there's an

1 operational necessity to share certain information.
2 So we permit the sharing of that information, but
3 prohibit the person who receives that information from
4 passing it along to those who are involved in the real
5 merchant activities, the selling or buying of
6 wholesale power. So I hope that adds a little bit.
7 MR. CAMERON: Thank you, Demi.
8 Let's go to this gentleman. This is, I
9 think, the last -- oh, there's two more? One more
10 after this. Okay. This is an issue we talked about
11 before about how often and under what circumstances do
12 you just routinely are supposed to talk to the TSO,
13 again, keeping in mind that there's not necessarily a
14 right answer to any of these questions.
15 Yes, sir.
16 MR. FARKAS: Steven Farkas from the
17 Westinghouse Owners Group.
18 To pursue this question further, a lot of
19 the plants use a 12-week planning cycle to come up
20 with their maintenance task. So this information that
21 we would be asking from the TSO would be on the order
22 of, you know, depending on what stage of the task
23 planning we're in, could be up to 12 weeks ahead of
24 time asking them, you know, is this switchyard going
25 to be out? Is that substation, this breaker? Are you

1 going to be doing relay work?

2 It's not, you know, day to day, you know,

3 we got up this morning and at shift change we want to

4 talk to the TSO and ask him what's wrong today. It's

5 12 weeks worth of knowing in the future what's wrong

6 and the question is: are we allowed to get that kind

7 of information from the TSO?

8 MR. CAMERON: Susan, this may --

9 MS. COURT: I don't know if we've actually

10 specifically addressed that, but we have not.

11 MR. CAMERON: Does this have something to

12 do with does there have to be an emergency or is there

13 something that might be necessary to prevent an

14 emergency, what is the day-to-day operations, what is

15 that type of --

16 MS. COURT: I think it is probably more of

17 the last. This is obviously not an emergency and the

18 Commission's rules don't talk about sharing

19 information to prevent an emergency as such, but

20 clearly what's contemplated by the day-to-day

21 operation is that you have to share information in

22 order to insure that day-to-day operation. Whether or

23 not this 12-week lead, specifically I don't think we

24 have specifically addressed.

25 But, Bruce, did you have a comment on

1 that? This is Bruce Poole who works in the
2 Reliability Division of FERC.
3 MR. POOLE: I guess I don't see how that
4 comes into play because all of the TSOs would have
5 their long-term planning programs, and anything that
6 was going to be taken out of service that far away
7 would have already been identified and should be
8 listed.
9 MR. CAMERON: Yes. Did you have a follow-
10 up question?
11 MR. KOZA: I just need to know are they
12 allowed to (speaking from an unmiked location).
13 MR. CAMERON: Okay.
14 MR. FARKAS: I was going to say all of our
15 transmission outages are posted on the Website, all of
16 them.
17 MR. CAMERON: Frank, do you want to? Did
18 you have an answer? Frank, do you want to repeat
19 that?
20 MR. KOZA: I was just going to say all of
21 the transmission outages in PJM are posted on the
22 Website. So the answer to your question is yes.
23 MR. CAMERON: Okay. I guess the question
24 I have for the NRC staff and for FERC is that the
25 generic letter is asking for information, not saying

1 that this is the right information to give us, but is
2 there a need for FERC to consult with the NRC on these
3 emergency day-to-day operation questions at all?
4 I mean, I don't know. I'm just asking.
5 MS. COURT: Well, I think that under the
6 memorandum of agreement, that if -- well, let me put
7 it this way. The memorandum of agreement definitely
8 contemplates communication between the two agencies.
9 Now, these types of questions though we
10 don't deal with on a day-to-day basis. The rules are
11 out there. Every company is required to have a
12 compliance officer. Every company is required to have
13 a compliance plan, and this, you know, has been in
14 effect now for over a year. So a lot of work has been
15 done.
16 As one gentleman alluded to, his company
17 had a very detailed legal memorandum on it as well.
18 So as far as the NRC and the FERC consulting, that's
19 something that really isn't -- I won't say it's not
20 practical. It's just not going to come up because we
21 don't necessarily have these types of questions come
22 up every day.
23 But I think that if we did have a question
24 that we needed to answer and we were going to put on
25 our frequently asked questions because we do plan on

updating our frequently asked questions on a regular basis and it did involve a nuclear plant, of course we would talk to you about that. No question about it.

MR. CAMERON: Okay. Thank you.

MR. JENKINS: And if we got a response from a generic letter, if there was a generic letter response from a licensee that says basically we can't get this information because FERC rules won't allow us to do that, then obviously we would be talking not only to them, but we would also be talking to --

MS. COURT: Right. Now, as is true for any agency, any federal agency, any state agency -- Jimmy is gone now -- the staff can go only as far as contemplated by the rules, you know, and what the staff does and I'm sure your staff does it as well, and I'm sure your staff does it as well, is staff will give informal advice as to what the rules mean, just informal interpretations, and those informal interpretations are now being, as I said, laid out on the Web page.

If we were to get a question that just simply was not contemplated by the existing rules, what we would do is bring that to the Commissioners' attention to get greater clarity. So within that limit that we can only go as far as the current rules

1 are structured, and I'm stating the obvious, but
2 sometimes that's necessary.
3 I can assure you and I feel very
4 comfortable speaking on behalf of the Chairman of the
5 agency with whom I spoke this morning before I came
6 here that we would work very closely with you on these
7 types of questions.
8 MR. CAMERON: Okay. That's good. I think
9 you pointed out a couple of different ways where if
10 there was a need, there will be an answer.
11 Mike Mayfield.
12 MR. MAYFIELD: I just wanted to point out
13 that I think it's Brian Sheron mentioned this morning
14 the FERC Commission and our Commission are
15 anticipating a joint meeting in the foreseeable future
16 I'm told, and if this is something that is starting to
17 come out as a response to the generic letter, I'm
18 reasonably sure at first at the staff level and
19 potentially at the joint Commission level, this would
20 be something that would be open for discussion.
21 And if, as Susan suggests, it's not
22 something contemplated by the regulations I'm
23 reasonably sure that the two agencies can figure out
24 how to come to grips with that so that it does get
25 addressed.

1 MS. COURT: Absolutely, and Chairman
2 Kellaher looks for ward to having that meeting. That
3 was one of the reasons that we were talking about the
4 NRC this morning.
5 MR. CAMERON: Okay, good. Thank you.
6 Let's go to Keith and then we'll go to
7 Jennifer.
8 MR. JURY: Yeah, one last question on that
9 topic, and, Mike, I appreciate the fact that FERC and
10 the NRC are going to work together. I think that
11 where Exelon is and I think a number of other
12 utilities is it appears that the NRC is looking for
13 deeper and more thorough communications than we
14 believe the FERC rules currently allow, and I heard a
15 question put on the table by Mr. Alexander, I believe,
16 and said could FERC review the generic letter and
17 insure that the level of information that's being
18 asked for by the NRC can be shared.
19 I believe I'd push the "I believe" button
20 on future meetings, but we have a generic letter
21 that's supposed to come out by the end of this month.
22 I think it would serve everybody in this room,
23 particularly the utilities and the NRC, very well if
24 that review could occur in FERC and the NRC could get
25 together and say this is consistent. It's okay that

1 the nuclear plants give this level of information.
2 And if that's not the case that the NRC
3 revise the generic letter before it's issued to go
4 through the response and the RAI process. It just
5 makes absolute sense that it would get reviewed
6 beforehand and not later on down the road when we're
7 trying to implement this this summer.
8 MS. COURT: We'd be more than happy to
9 look at it. Again, we have to function within the
10 existing rules, and so to the extent that the
11 information contemplated by the GL is covered by those
12 rules and we can define it, I think we would be more
13 than happy to say that.
14 I mean, part of the reason that we're here
15 is to be able to provide certain things for the
16 record, and so anyway, I mean, a general -- Demi, do
17 you want to say something?
18 MR. CAMERON: Let me get you on the
19 record, Demi.
20 MS. ANAS: I just want to reiterate that
21 there's nothing in the rules that prohibits the
22 nuclear power plant from providing information to the
23 transmission provider. I think that one question
24 implied that. Did I say it -- nothing prohibits the
25 nuclear power plant -- right, okay. But I think the

one question focused on the nuclear power plant providing information in response to the GL.

It's the information prohibition applies to the transmission provider. So the nuclear power plant operator is free to give the transmission provider any information without any restrictions.

PARTICIPANT: We understand that.

MR. CAMERON: We're not getting this. Okay. Thank you. I think we understand that point, and I think we understand what Keith is going to say.

Keep in mind that as Ronaldo pointed out if in response to these questions a licensee came back with a response that said, well, we have these procedures in place with the TSO, but note that we cannot get this other type of information from the TSO because FERC rules would prevent that, then that would be an issue that would -- that would joint the issue at that point.

I'm not saying that there needs to be dialogue before the -- that it wouldn't be a good idea to have dialogue on this before the generic letter goes out, but I still see the generic letter asking for, well, what type -- you know, what information do you have?

I don't know if David or Frank -- do you

1 have anything on this at all, David?

2 MR. NEVIUS: Well, our draft standard --

3 and Terry can help me here -- does contemplate

4 transmission providers, transmission entities sharing

5 a good bit of information with the nuclear plant

6 operators, coordination of maintenance and planned

7 outages and so on, and a swell as real time operating

8 information.

9 And I think as Susan said, as long as the

10 nuclear plant operator does not then turn around and

11 share that with their merchant side, there's not a

12 problem.

13 MR. CAMERON: Okay, and, Terry, do you

14 want to add anything to that?

15 MR. CRAWLEY: Well, we did think about

16 this --

17 PARTICIPANT: I was looking at R-5, Terry.

18 MR. CRAWLEY: -- as we were drafting the

19 standard. Right. R-5 basically says per agreements,

20 per the agreements that the entities would develop,

21 the designated transmission entity, which could be the

22 transmission operator, the reliability coordinator or

23 depending on who the correct entity is, and the

24 nuclear plant shall coordinate planned outages and

25 maintenance activities affecting the nuclear plant

1 interface requirements.

2 So the concern is the impact that these

3 activities could have on the plant and on their

4 ability to meet their licensing requirements for safe

5 shutdown and, you know, having adequate off-site

6 power.

7 So in fact, we were discussing that maybe

8 we had some discussion about adding something into the

9 standard to actually strengthen the requirement to

10 address any standards of conduct requirements and make

11 sure that there are no problem -- basically grease the

12 skids -- make sure there's no problem. You know,

13 discuss these things up front and make sure there are

14 no problems up front.

15 Now, if the standard is not out yet and

16 we're already having these concerns, so it's kind of

17 after the fact, but let me say one thing. I work on

18 the nuclear plant side, okay, and I think this

19 communication is very important that it take place,

20 okay, for the safety of these plants, but after what

21 I've heard here, if I were the transmission operator

22 or reliability coordinator, I've got a FERC rule that

23 I don't want to violate. I don't have anything from

24 the nuclear side right now that tells me what I can

25 and cannot do. I'm going to land on the conservative

1 side and make sure I don't violate the FERC rule so
2 that I can understand why a communication may not take
3 place in this environment today.
4 So that's all I'm going to say and shut up
5 and sit down.
6 MR. CAMERON: Thank you, Terry.
7 MS. COURT: Okay. One thing, and I think
8 what you're hearing from the FERC representatives here
9 is that we're a little incredulous, I guess, because
10 we thought that the rule provided the type of
11 communication and was an impediment to the type of
12 communication necessary to enable the nuclear facility
13 to get off-site power.
14 So you know, if that were the case, I
15 mean, that would not be as contemplated by the rule,
16 and I think what we're going to need is some really
17 specific examples of this, as why that would be a
18 problem.
19 Generally, we will look at the draft GL.
20 I'm not sure if the draft GL has the specifics in
21 there that is going to basically give you all the
22 comfort that you want, you know, just reviewing it
23 very quickly without looking at it for the specific
24 thing.
25 I didn't see how -- nothing triggered

1 necessarily a concern vis-a-vis the FERC's rules. So
2 there's something going on here or there's
3 something -- there's an undercurrent here which is
4 kind of a mystery to me because, again, knowing what
5 the purpose of the rule is and what the exceptions are
6 intended to accomplish.
7 So there's maybe just some more
8 communication that is needed in that regard. I am not
9 comfortable with promising that the FERC, the
10 Commission, you know, in a quorum voting will comment
11 on the generic letter. I don't think that is really
12 appropriate, and rarely, rarely, in 24 years at the
13 FERC have I seen the FERC itself as the Commission
14 weigh in on another agency's rulemaking or the
15 equivalent of a rulemaking. I may be able to give you
16 some informal staff comments on it.
17 MR. JENKINS: One other aspect of this,
18 and I guess this is what my boss is getting up to say
19 is that Brian Sheron this morning mentioned that we
20 will be pursuing a temporary instruction for the
21 summer of 2006. I wish we didn't have to do that, but
22 we need to have assurances for this next period, and
23 the generic letter getting out and getting the
24 information back, especially having this kind of a
25 dialogue, will give us information we can use to make

1 a smarter temporary instruction type of an assessment.
2 So I don't know if I hit the mark there.
3 Did I?
4 MR. MAYFIELD: Well, I guess I was going
5 to say two things. One, Susan, first of all we would
6 very much appreciate any comment now or before or
7 after the generic letter goes out just to make sure
8 we're all sort of on the same page.
9 MS. COURT: Absolutely.
10 MR. MAYFIELD: Once the generic letter is
11 out, if you're having trouble responding the questions
12 because you somehow feel there is a legal prohibition
13 to the TSO providing you information, that would be a
14 really good answer to put in the generic letter
15 telling us we need to not do anything because you
16 might not be able to answer the question just as a
17 nonstarter.
18 So if that prohibition exists, your legal
19 departments believe it exists, that would be a really
20 good answer, and I think as Chip said, that would join
21 the issue between the two commissions, but to set and
22 continue to wring our hands with hypotheticals, we
23 need some specifics to deal with, and then I'm sure
24 the two Commission will sit down and make this thing
25 come out in the right place.

1 But this issue isn't something that I see
2 as in the best interest of the Nuclear Regulatory
3 Commission to not move forward with. If it's a real
4 issue, then it's something where we need some
5 clarification between the two Commissions to make sure
6 you're able to get the kind of information you need to
7 assure the safety of your plans.
8 MS. COURT: Thank you.
9 MR. CAMERON: Okay. Thanks, Mike.
10 And this is an important issue obviously,
11 and there's a few jagged edges here, and I think that
12 part of Susan being perplexed is because of the fact
13 that people are reading implications into the generic
14 letter rather than just tell us what procedures you
15 have in place.
16 They're thinking that there's another shoe
17 that's going to be falling there, and I think the
18 staff is probably going to wait for that other shoe to
19 fall, and they want to see what information comes in.
20 But as Mike pointed out a legitimate
21 answer may be that while we don't have this type of
22 procedure because we don't think that we're allowed to
23 get it from --
24 MS. COURT: You know, I think the thing
25 that's perplexing, too, and Demi has been living and

1 breathing and drinking these rules for many years, I
2 mentioned the comment that the Commission itself and
3 the exception that the Commission itself made in
4 response to one of the commenters in the rulemaking
5 proceeding.
6 But, Demi, correct me if I'm wrong. Has
7 this been a problem? This is like news?
8 MS. ANAS: This is actually one aspect of
9 the rule that we thought didn't change. We had
10 hundreds and hundreds of comments and opinions during
11 the rulemaking proceeding over a three and a half year
12 span. Only one person brought it up.
13 You know, we can only, as Susan said, we
14 can only articulate what the Commission has already
15 said, and everybody had the opportunity to participate
16 in that rulemaking proceeding. So the Commission
17 addressed the comment that they had received.
18 I think had people fleshed it out more
19 during the rulemaking proceeding, we might be able to
20 tell you a little bit more now because the Commission
21 would have spoken on it. So, you know --
22 MS. COURT: But even then, Demi, have we
23 gotten even questions from the nuclear industry?
24 MS. ANAS: I got one, I think, over the
25 summer.

1 MS. COURT: Okay. So that said, let me
2 just assure you that just because the Commission
3 hasn't spoken to it specifically because only one or
4 two people have raised it in all of that time, that we
5 are -- let me put it positively -- we are open minded
6 about this and we want to hear if there are any
7 problems and if there are any impediments.
8 And I reiterate that the two agencies will
9 work closely together to insure they are not. We're
10 not going to necessarily -- and I'm sure that the NRC
11 wouldn't want this generic letter proceeding to be
12 used to circumvent a set of commercial regulations.
13 I'm sure they wouldn't want to do something like that.
14 MR. CAMERON: I think we can say we
15 wouldn't.
16 MS. COURT: I think it's safe to say, too,
17 but we're talking about operations here. We're
18 talking about reliability here, and I think we're all
19 on the same page as far as making sure that both the
20 grid and the plants are absolutely reliable on behalf
21 of this country. I mean there's no question about
22 that. Everybody in this room, everybody at both
23 agencies, we all have the same goal. So we'll work
24 together.
25 MR. CAMERON: Okay. Thank you, Susan.

1 We're going to go to Frank and then
2 Jennifer, and I think we're going to close off for
3 today. We're going to come back tomorrow, and
4 tomorrow is basically going to be reprise of a lot of
5 these issues because we're going to hear from the
6 industry possibly on a lot of the same issues, and
7 then we have an open session.
8 So we're running about 15 minutes behind
9 time. So we want to try to get you out in time.
10 Frank and then we'll go to Jennifer.
11 MR. KOZA: Thanks, Chip.
12 I just want to amplify Susan's points.
13 Our interpretation is there are no impediments to
14 sharing information with nuclear power plants. When
15 the issue is nuclear safety, we will share anything
16 with the nuclear power plants, and I don't think there
17 are any -- I have to agree with it. I don't think
18 there are any impediments to sharing information.
19 Now, there are impediments on the
20 commercial side with the further dissemination of some
21 of that stuff, but regarding communication with
22 nuclear power plants, there's nothing we wouldn't
23 share in a nuclear safety environment.
24 MR. CAMERON: Okay. Great. Thank you,
25 Frank.

1 And Jennifer.

2 MS. WEBER: Jennifer Weber, TVA

3 Operations.

4 This is a question mostly for FERC,

5 although NERC may have a point. This is about undue

6 preference. What is FERC's position on providing

7 preferential service to a class of generation?

8 Because generally speaking nuclear plants

9 require higher voltage requirements than anyone else

10 that uses the grid, and usually the consequences of

11 not being able to meet that is a controlled, orderly

12 shutdown of a unit which would not impact bulk system

13 reliability.

14 MS. COURT: Let me just give you the

15 classic legal answer from both the PAR Act and the GAS

16 Act.

17 Both acts, PAR Act here is the relevant

18 one, prohibit undue preference, undue discrimination.

19 Unlike some other statutes that forbid discrimination,

20 our statute forbids undue discrimination. So their

21 justified discrimination is permissible under the

22 federal PAR Act, and so you know, if there is a

23 reasonable justification for discriminating in favor

24 of one class of customers over another class of

25 customers, over one customer versus another one, the

1 Commission has spoken to how competition and meeting
2 competition could be a justification for
3 discrimination.
4 Contracting by itself is discriminatory.
5 In other words, the PAR Act is based on contract
6 carriage, and so is the GAS Act. Entering into a
7 contract actually is a form of discrimination because
8 you're locking in a certain amount of capacity or
9 you're locking something in.
10 So the statute in our regulations,
11 accordingly, do not prohibit preference for one group.
12 If the preference is justified, it is not undue, and
13 that's decided on a case-by-case basis.
14 MR. CAMERON: Okay. Thank you.
15 We've had a request from some people who
16 may not be here tomorrow to just briefly try to
17 address this issue which came up before, the issue
18 being one that Frank Koza also put up for us.
19 So let's take a few more minutes and talk
20 to this and then we'll adjourn.
21 What level of additional notification or
22 discussion should there be? And, you know, Frank is
23 basically saying that there's going to be protocols on
24 notification, level of trust and notifications will
25 occur, and Ronaldo, well, someone responds to the

1 generic letter with that. You know, that's a
2 response.
3 MR. JENKINS: If I was the licensee in the
4 PJM system and I said, okay, describe -- I was
5 responding to this question -- describe the procedures
6 to periodically check with the TSO to determine the
7 grid conditions, et cetera.
8 I would then go back to the PJM
9 procedures. I would refer to those as the basis in
10 which I run my plant and here's processed that we
11 follow and the notifications that we have committed
12 to. That would the answer.
13 MR. CAMERON: Okay. So you've heard
14 Ronaldo's take on that. Let's -- I'm going to Mr.
15 Thorson a minute. Let me go to you to see, John, what
16 you think of that.
17 MR. GRANGER: This is John Granger, FPO.
18 Well, the real question is are you
19 requiring the nuclear power plant operators to contact
20 the TSO on a regular basis to, you know, determine
21 the status of the grid. Is that going to be a
22 requirement?
23 MR. JENKINS: The GL doesn't contain any
24 requirements. If you're saying whether the staff has
25 a preference one way or the other, I don't think that

1 the higher goal, if I can use that term, is that we
2 are interested in making sure that nuclear power
3 plants are working with the transmission system
4 operators to insure reliable off-site power, and we're
5 not trying to prescribe any particular limits or
6 numbers or anything of that nature.
7 Obviously if something is working and it's
8 working well, then we will not have a problem with it.
9 It's only when there's an indication that this might
10 create a problem that staff might come back and ask an
11 additional question.
12 And so that's pretty much -- does that
13 answer your question?
14 MR. CAMERON: John, this runs through this
15 whole GL, is that people are reading requirements into
16 it. How would that question -- how would that read
17 that would alleviate your concern that there's a
18 requirement?
19 MR. GRANGER: Well, it simply says
20 describe the procedures, you know, that you use to
21 check the TSO periodically. To me that's saying if
22 you don't have procedures that require you to check
23 with the TSO, then that's not a desired, okay,
24 condition.
25 So it seems like it could be reworded such

1 that, you know, if there was an agreement in place
2 between the TSO and the NPP and it was working and you
3 were notified if there was a condition of instability
4 or degradable, then that would be acceptable, period.
5 It's not like there is an onus that we
6 have to contact the TSO on any periodic basis, you
7 know, unless there's a problem.
8 MR. CAMERON: Okay, and I think I see some
9 agreement with you on this and perhaps the staff needs
10 to think about, even though it's not intending
11 anything, maybe there's a way to reduce the anxiety of
12 the way these questions are asked.
13 And let's go to Mike Mayfield.
14 MR. MAYFIELD: Two points. First, Frank,
15 I think in your presentation you said you'd like to
16 not create communication centers to deal with this.
17 As much as I might like to own stock in the
18 telecommunications world, I don't. So, no, we're not
19 looking to create communications centers.
20 I did commit this morning to Mr. Rosenblum
21 that we would go back and look at was it 1(a) versus
22 1(d), whatever those two questions are. We'll go back
23 and look at it and try to make clear on this issue.
24 You know, I don't know what more we can do
25 today. We appreciate the sentiment. We understand

1 the concern, and we'll go back and try and make sure
2 we're clear on what we're trying to do with these two
3 questions.
4 MR. CAMERON: Great, and you heard Mike
5 make that commitment, and I guess I would just ask you
6 in preparation for tomorrow, did the types of things
7 you heard today from the NRC staff, including going
8 back to look at some of these issues, is that getting
9 to some of the concerns that you have with the generic
10 letter?
11 Because we want to make sure that we're
12 making some progress here.
13 And I just would leave you with that
14 because I think we need to adjourn at this point and
15 take up tomorrow at 8:30. It's going to be a reprise
16 of the day today, perhaps more focused, and so I'd
17 just ask you to think about those questions.
18 If you're not going to be here tomorrow,
19 if you have a concern, a question, please use one of
20 the comment cards and fill it out, and we will put
21 that into the mix.
22 Correct, Ronaldo?
23 MR. JENKINS: Correct.
24 MR. CAMERON: And I just have to ask you
25 to give this final panel and also will include the

1 previous panel in that round of applause for --
2 (Applause.)
3 MR. CAMERON: And thank all of you. I'm
4 sorry that we didn't get to everybody today, but we
5 will get it in the mix tomorrow.
6 (Whereupon, at 4:19 p.m., the meeting was
7 adjourned, to reconvene at 8:30 a.m., Tuesday, January
8 10, 2005.)
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