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U.S. NUCLEAR REGULATORY COMMISSION

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THE GENERIC LETTER ON GRID RELIABILITY

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PUBLIC MEETING/WORKSHOP

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MONDAY,

JANUARY 9, 2006

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The meeting was held in the Waterford Suite of the Hyatt Regency Bethesda, 7400 Wisconsin Avenue, Bethesda, Maryland, Chip Cameron moderating.

C O N T E N T S

P R O C E E D I N G S

(8:30 a.m.)

MR. CAMERON: Hi. My name is Chip Cameron. I'm the Special Counsel for Public Liaison within the Office of General Counsel at the Nuclear Regulatory Commission, and it's my pleasure to serve as your facilitator for this meeting today and tomorrow, and I just want to welcome all of you.

I have a few brief comments about meeting process before we get into the substance of our discussions today, and I just want to talk a little bit about what the focus of the meeting is, the format of the meeting, some real simple ground rules, and just give you a real quick agenda overview.

In terms of the focus of the meeting, you're going to hear more about this from Mr. Jim Dyer, who is the Director of the Office of Nuclear Reactor Regulation at the NRC, but at least three questions, I think, for you are:

Are the objectives of the generic letter on grid reliability clear?

Are the information or is the information requested by the questions in the generic letter, are they clear what information the NRC needs?

And is it clear what the tie is between

the objectives of the generic letter and the questions seeking information?

And the NRC is going to give you information on all of this and then we want to hear any comments that you might have, any questions that you might have on all of this.

In terms of format, we're going to be basically having some presentations on the generic letter. We're going to have some panels of various organizations, and we're going to go to you for discussion and questions.

We built some redundancy into the agenda. For example, there are going to be panels on the generic or on the questions in the generic letter, but also we have a panel tomorrow, an industry panel with NEI and INPO and the NRC, and obviously that's going to revisit some of the issues that we talk about.

Today we also have a general question and answer question at the end of tomorrow morning so that we can revisit some issues that you may not have had a chance to explore more fully today.

In terms of ground rules, when we do get to the discussion part of the agenda, if you have something that you want to say, please signal me, and I'll try to come out with the cordless mic. We also have microphones in the audience, but I would hope that we will not have people queuing up at the mics. That's why I'll try to get to you with cordless.

When I do get to you, please introduce yourself to us, your name and affiliation, if appropriate.

I would ask that only one person talk at a time for two important reasons. One is that so we can give our full attention to whomever has the floor at the moment, and secondly, so that we can get a clear transcript. We have our stenographer with us in the back of the room. His name is also Chip. We're making it easy for you. For future meetings, just assume the facilitator's name is Chip and the stenographer's name is Chip. So all very simple. That's sort of a joke, I guess.

(Laughter.)

MR. CAMERON: But not a very big one.

When we do get to the panels, and the panels are going to go right through in their presentations, we're going to try to keep the presentations brief, about 15 minutes each. When we're done with the panel presentations, we're going to give them an opportunity to ask questions of each 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 up rather than using the cards to get your comment before us, but obviously if we run out of time at some point, please put your comments on there.

You can also put a question on there, and we'll make sure when we get to the general discussion area tomorrow morning before we close, we'll go through those questions and see if there's any that have not been answered and then we'll use them to answer those questions.

And finally, in terms of the agenda, we're going to have some introductory remarks this morning from Mr. Jim Dyer, who is the Director of Nuclear Reactor Regulation, and from Mr. Brian Sheron, who is the Associate Director of Energy and Safety Systems in our Office of Nuclear Reactor Regulation.

There's an opportunity for some clarifying questions to both Jim and Brian after that, and then we're going to move to an overview of the generic letter, and we have Mr. Paul Gill from the NRC staff who's going to give you that overview. Again, an opportunity for clarifying questions.

We do have specific items on the agenda for the questions in the GL. So we don't necessarily want to get into a big discussion after Paul's presentation, but we do want to give you the opportunity to ask some questions there.

Next we have risk insights. The NRC and EPRI are going to present that. After that discussion we'll go to transmission systems, and we have an excellent panel who's going to present on that.

We're going to try to adjourn at four o'clock today. At 11:30, there's a lunch break. In the morning, we have a break scheduled for 10:20; in the afternoon a break at 2:45; and tomorrow we're going to get started at 8:30.

I just would thank you all for being here. It's going to be an interesting day and a half, and with that I'm going to turn it over to Jim Dyer.

Jim.

MR. DYER: Is this thing hooked up? Okay, good. The reason I asked is there's a cable sitting here.

(Laughter.)

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

First of all, let me say thanks for coming out on a Monday, particularly those of you who traveled in from afar.

Just to get a profile of what my audience is today, is there a Federal Energy Regulatory

Commission member here, a member of FERC?

(Show of hands.)

MR. DYER: Well, managed to come in. Good. Welcome.

How about North American Electric Liability Council? Anybody?

(No response.)

MR. DYER: Any members of transmission system operators, independent system operators?

(Show of hands.)

MR. DYER: Somebody in the back, the middle, the end. Good.

How about utilities, NRC licensees or otherwise? What's the utility reps.?

(Show of hands.)

MR. DYER: Good. How about NRC? How many of the NRC staff have we got?

(Show of hands.)

MR. DYER: Okay. Good. Look like a good representation, which is important for a workshop.

The intent of my opening remarks is really just from a high level to talk a little bit about what this generic letter, why we're doing it, what this generic letter means to me, and then I'm going to leave and let you try to figure out if we're in alignment in that.

But I think the actual purpose of this meeting was really outlined in a Commission staff requirements memorandum to us that outlined it. It really asked us to look at three questions:

What is intended by the generic letter questions?

What does the NRC expect from the answers?

And how do we anticipate using this information?

And the challenge we have is with the proposed generic letter right now is to take a look at whether we need to make changes to that, you know, conduct this meeting, decide whether we need to make changes to the generic letter to accomplish what we want to, and then get back to the Commission to support getting the generic letter issued by the end of the month.

And that goes to allowing the utilities and NRC licensees time to respond and then for us to get back and to be prepared for the summer of '06.

So just with that in mind, let me give you a couple of my high level views, I guess, to frame the discussions today. And first of all, you know, this workshop is necessary. The Commission SRM that directed the staff, the only question about that was whether we held it before or after we issued the generic letter and based on schedule and talking to the Commission, you know, we're doing it now before we've issued the generic letter so that you have the opportunity to influence how we can adjust the questions in that.

And on a higher level, we're still working, you know, in the post August of 2003 environment, whether it was the grid drop of the northeast and into the -- I've been into the Midwest, and we had our lessons learned. We've had a number of action items coming out of that.

But the one question that still is before me is whether our current regulations for off-site power are adequate in the current deregulated environment, and that's a question that, you know, we asked ourselves that the NRC staff took a look at and reviewed, and we came to the conclusion they are.

You know, off-site power is considered in licensing of the plan as preferred power source, and it provides defense in depth to the on-site power supply. So it has a regulatory purpose, and it's a question of our regulations, and we really looked at three regulations that are outlined in the generic letter.

One, the general design criteria of Part 50 that are translated from operating reactors into your technical specifications and your licensing basis; the maintenance rule, and particularly, 10 CFR 5065(a)(4) for risk management; and lastly, the station blackout rule, 10 CFR 50.63, which concerns coping studies and procedures for recovery.

You know, one of the things we have though, one of the questions we have though is whether our understanding of the regulation reflects the way the industry implements these regulations, and making sure we're in alignment is the purpose of this, of the generic letter.

And in the generic letter when we worked through the Office of General Counsel and to get the interpretation of the regulations and to make sure that our understanding as articulated in the generic letter is consistent with OGC's, you know, is supported by the Office of General Counsel, and it is, and so that sort of lays out the way we view the world for off-site power with respect to these three regulations.

Now, we've got the results from the TIs that we conducted prior to the summer of '05 and the summer of '04 where we went out and we took at some of these areas, and that's what leads us to question whether or not the implementation really reflects the way we understand the regulations and our views on compliance with what the regulations are.

And I'll acknowledge that we may not have been asking the right questions, that we may have miscommunicated. We may not have looked under or asked the right people in the organization to get it, and our decision was to go forward with this generic letter in order to facilitate that general understanding of whether or not implementation is as the NRC sees compliance.

Let me talk a little more specifics in the four areas that are outlined in the generic letter. The generic letter is framed. It has eight questions in the four areas concerning the three regulations. So let me just give you my views on what the NRC needs are and what we don't need from the generic letter in these areas.

And the first area is the general design criteria and the technical specifications which govern off-site power operability and operational constraints on nuclear power plants. You know, what the NRC needs to know is that if your off-site power source is unreliable that you'll declare it inoperable, enter it into the action statement and take actions to fix it and report it.

You know, nuclear power plants need off-site power when they've lost the output from the reactor and the generator. If the utilities -- if the nuclear power plant is the only one holding up the grid, then you're not operable, our view. If there's another plant on the grid, another supply onto your grid that if it's lost would cause you to trip and the off-site power to go away, then we don't think they're operable. That's not a reliable source of off-site power.

But one of the things we're not asking you to do is to come up with a double contingency, as I think I've heard discussed or I've been questioned in other avenues where you have to figure out how much of -- you know, whether or not a loss of another plant and then taken on top of that another loss of your plant.

Unless the two are interconnected, we're not looking for a double contingency or, you know, two layers -- that's it -- of defense in depth.

We're also not requiring you to use specific codes or real time contingency analysis methods. I think those are regulated by FERC, NERC and chosen by the transmission system operators' independent system operators.

So we're not trying to influence. You have to influence your transmission system operator. If, in fact, that's a question and the utilities can't get good information, we'd like to know about it. We'll address our counterparts in FERC and talk to NERC about whether or not there's adequate communications now.

But our understanding is that the system operators in that have the information and do that.

The maintenance rule, 10 CFR 5065(a)(4) requires power plant licensees to both assess and manage risk of maintenance activities. This includes considering whether in the grid conditions, and it's outlined in Reg. Guide 1.182 and endorses NEI 9301.

You know, what this regulation requires licensees to do is to be able to know the predicted grid conditions for the duration of a planned maintenance outage of a critical piece of equipment. From the NRC's perspective, recently research finalized their NUREG on grid activities, grid reliability, and in our view the grid is more unstable in the summer months and you really shouldn't be scheduling extended outages for diesel generators, batteries, and the turbine driven pumps during the time frame when your grid is predicted to be unstable. That's for long-term planning.

Also, the NRC recognizes that when you do schedule things that emerging conditions occur, that a grid you thought would be stable, something happens and it doesn't. What we really expect then is that you'll know about it when it happens and have a Plan B, you know, which may be to reschedule the maintenance, to accelerate the completion of it, or to back out based on what's the best interest in safety.

You know, the third area is the station blackout rule with respect to the coping capabilities where each plan is required to cope with the station blackout for a specific period of time based on the vulnerabilities that are expected of that plan.

One of those vulnerability considerations is loss of off-site power frequency. You know, what we need to know is that plants are updating their analysis to make sure they're in the right bin and have the right coping abilities, given the conditions of their local grid around them and that they consider all of the loss of off-site power events, that they're not arbitrarily excluding events because of the potential root cause.

And the last area is also the station blackout rule, and that also requires plant staff procedures to restore off-site power and using nearby sources. You know, what the NRC needs to know is that the deregulated environment doesn't prevent those kinds of recovery procedures from being implemented and that they're still current under the current environment.

You know, in the deregulated environment that we're operating in today, the utilities, you know, they're not an island. They don't control all these different factors anymore. There's a number of different players, and that's why I'm very pleased that we've got, you know, FERC and the transmission system operators and a wide variety of utilities in our licensees and in our staff.

You know, what we need to do is to have a healthy discussion, and I'll be the first one to admit, you know, I read through the generic letter again this weekend after I had spoken to NEI and taken a look at it from a different perspective, and I think we need to fill in some of the questions.

So from my perspective, the NRC shouldn't be dug into the wording as it is right now. If the intent is to get to a healthy exchange of information and communication about how the grid is managed by the nuclear power plant licensees to the NRC, it's not us trying to infringe ourselves and get into managing the grid ourselves, but it makes sure we have to have a healthy discussion and dialogue about how that occurs.

So I wish you the best in the next two days. I think it's a very important meeting. I think what we need to do is to try to get to, you know, a simple understanding of what's expected on the NRC's part and understanding what the kinds of answers that we're going to get and have a good dialogue about that so that when the written submittals come in later this year and it gets close to the summer months, that we can have the assurances and I can assure the Commission that we're ready for any kind of challenging grid summer conditions.

So with that, let me just turn it over to Brian and let him make some opening remarks.

MR. SHERON: Good morning. I don't have too much more to say than what Jim has already told you. I share his thoughts completely in terms of the purpose of the workshop and everything.

For those of you who don't know me, I'm Brian Sheron. I'm the Associate Director for

Engineering and System Safety. I guess it would be easier if I told you my name is Chip, right?

(Laughter.)

MR. SHERON: Anyway, I want to reiterate that the principal goal of the workshop is for everyone to have a common understanding of the questions contained in the generic letter. Because of concerns that were expressed by the industry, the Commission issued a staff requirements memorandum as Jim said on December 20th that instructed us to hold a public workshop to clarify the questions contained in the generic letter.

I want to point out this is not an opportunity. This is not an additional comment period for the generic letter. I mean, that has come and gone. This is a workshop to help clarify what's in the letter.

If changes are needed, as Jim said, to the letter to clarify what we're looking for, we will revise the letter accordingly, but I just want to reiterate that we're not back in the public comment period.

We plan on issuing the generic letter no later than January 27th of this year, and we're also making preparations to issue a temporary instruction to our inspectors that will provide guidance for performing inspections in the area of off-site power.

We're going to review the results of these inspections, and we'll determine whether nuclear power plants are prepared for continued safe operation during the summer of 2006.

Let me digress a second here. It was actually because of deregulation in the electric industry and as well as the operating events in the past few years, including the August 14th, 2003 East Coast blackout. The reliability of the grid has come into question.

Our initial assessment is that our current regulations remain adequate, and I think Jim pointed out the three that we believe apply here, GDC-17, the station blackout rule, and the maintenance rule.

However, we believe that additional actions are required to provide assurance that the licensees remain in compliance with the regulations. This is not a new concept. Okay?

As times change, as the situation changes in nuclear plants, we reexamine our regulations for whether they're still relevant, whether they still apply. In many cases they still apply, but what we need is because of changing situations in the industry, we need further assurance that compliance is still -- you know, that plants are still complying with the regulations.

And for that reason sometimes we believe that because of different circumstances, licensees have to take additional actions. As I said, these regulations are embodied in GDC-17, which is electric power systems; 5065, the maintenance rule; and 5063, the station blackout rule.

Either licensees need to provide us with further assurance of a reliable off-site power supply. Now, remember, a generic letter is just a request for information under 50.54(f). Okay? It is not a requirement. It just seeks information, and really what we're asking you is we're saying that we are questioning whether or not you are still in compliance with these regulations for the following reasons, and we outlined them in the generic letter.

And so what we're asking you is we're saying if you still believe that you're in compliance, then you need to tell us why you believe you're in compliance, but if you agree with these concerns that we've articulated in the generic letter, we are proposing that there are some actions that we think are necessary that will provide the assurance that you are in compliance, and you need to tell us whether or not you intend to take these actions or, if not, then what actions do you intend to take to demonstrate compliance and to address the staff's concerns, or if you're not going to take actions, to explain why you don't believe any actions are necessary.

We will take that information then and we will decide whether or not we believe you've made a sufficient case for compliance or whether we need to take further regulatory action.

But I do want to emphasize that this is a generic letter and it's a request for information. It's not imposing any new requirement.

As I said, either licensees need to provide us with further assurance of reliable off-site power supply, which is the focus of the generic letter, or we may need to revisit past decisions that were made based on the assumption of a reliable off-site power supply.

For example, extended diesel generator allowed outage times where licensees have come in and made, using risk arguments based on the reliability of off-site power that they can go from 72 hours, for example, to a 14-day allowed outage time, and we need to go back. We may have to go back and revisit and say is that still a valid assumption to make that the off-site power remains reliable enough to warrant this kind of a tech spec change.

The other thing we're obviously concerned about, and I think Jim alluded to it, is the seasonal variations in the likelihood of losing off-site power and whether licensees need to take further actions to make sure, for example, that you're not taking diesels or turbine driven pumps or batteries or the like out of service during periods when there's probably a much higher likelihood of losing off-site power, for example, in the summer months when there's a lot of electrical storms, when there's hurricanes that are bearing down on the coasts and so forth.

We need to make sure that the plants are at their maximum readiness during these periods.

I want to reiterate we understand -- you know, I've heard some concern that we were trying to regulate the grid, and I want to emphasize that we understand our limits of authority as a regulatory agency, and we are not attempting to regulate the grid.

But we want to make sure that we understand what the reliability of the grid is so that we can take appropriate actions with regard to how you operate your plants.

To minimize stress in this area that may be caused by interfacing, the staff will continue to work with the Federal Energy Regulatory Commission to insure that the two regulatory bodies are fully coordinated. In fact, our Commission is planning to meet with the Federal Energy Regulatory Commission in the near future, although I don't think a date has been actually set yet.

In closing, I just want to remind you NRC's regulatory responsibility is to insure nuclear power plant safety. We believe issuing a grid reliability letter and ultimately reviewing the licensee responses will allow the staff to determine if licensees are adequately complying with the regulations.

With that, Chip, I'm finished. We'll turn it over to you if there are questions.

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

We may not have Jim and Brian for the entirety of the meeting. So we wanted to give you an opportunity to ask any questions you might have based on the remarks that you heard from both Jim and Brian this morning.

And let's go back to this gentleman, and we need to get everything into the microphone so that we have it on the transcript, and if you could just introduce yourself to us, sir.

MR. ALEXANDER: Hi. I'm Steve Alexander. I'm with the Maintenance Rule Group at the NRC, and actually I was just here to answer questions in case there are any beyond what Paul Gill says about the maintenance rule.

MR. CAMERON: Okay. Thank you very much.

Any questions for Jim and Brian based on what you heard this morning?

Okay. Alex, please introduce yourself.

MR. MARION: Alex Marion, NEI.

I'm getting the sense that the NRC has already drawn some conclusions on the performance of the grid in terms of reliability. Is there any data that's been published that's been shared for peer review?

MR. CAMERON: Okay. Thank you, Alex.

Jim or Brian, on data, and we may be getting into that in more depth later on.

MR. DYER: I don't have the details.

MR. RAUGHLEY: That's part of a presentation later this morning. NERC/P is giving us some data, and we've worked with them to analyze that. We'll be showing some of the results.

MR. CAMERON: Okay. This is Bill Raughley from NRC staff.

MR. RAUGHLEY: Bill from NRC research staff.

MR. CAMERON: Okay. So we'll put that in the parking lot.

MR. DYER: Alex though I will say that I think that as I said before, I think we had a research study that's been out, and I think you've commented on it. We referred to it in the draft stages at the last Commission meeting where our review of loss of off-site power events since 1997, it has changed. They're, you know, grid centered versus plant centered, and the duration has changed, and that has had some influence on us.

Again, you know, the initiating events, one of the action items we took away after the August 2003 blackout, you know, the power plants performed well, but we took a look at what if. What if there had been extended diesel outages? What if? And we asked ourselves the question do we have assurance that that's the way the plants are always going to operate and always the conditions going to be and if the conditions occur as well as what can we do to enhance the communications to make sure that there's an understanding if the grid does get into an unstable condition, that the power plants are going to know that.

And so that's sort of the background that led us to where we're at right now, but as far as coming up with a conclusive risk argument that says that we have to demonstrate to show that this is absolutely positively necessary, I don't think we need to do it, and like I said, we've got some information we're going to share today.

MR. CAMERON: Okay. Thanks, Jim.

MR. SHERON: Chip, if I could.

MR. CAMERON: Go ahead, Brian.

MR. SHERON: I wanted to bring in one thing on that, which I think has at least influenced me a little bit, and that is that, you know, a lot of times the NRC gets criticized for being a day late and a dollar short in terms of waiting for something to happen before we take action. You know, we are well aware that, for example, the licensing form which NEI sponsored back in November, one of the senior executives in his opening remarks pointed out that I 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 mention four key words that are used throughout the generic letter and in the discussion that have a different meaning to the transmission side of things than they do to the nuclear house and to perhaps suggest that these terms be defined very clearly in the generic letter and in our discussions.

The first term is "unit trip." It is used throughout the generic letter. The grid always operates so that their system is secure for loss of a unit, but I think perhaps in the generic letter you're referring more to a design basis event, such as a LOCA shutdown or a full load rejection.

Those are very different events in terms of grid impact from a simple unit trip.

The second term is "off-site power," and I think that needs to be distinguished clearly between an external source of power to the plant versus a qualified off-site power source for tech spec purposes. Those are different.

To be a qualified off-site source, you have to postulate, again, a design basis and insure that your voltage would hold up in that postulated event. That's different from the physical loss of an external power source.

And then the third and fourth words are

"reliable" and "unstable." Reliability and stability have very specific definitions in the NERC side of the house in transmission. Like reliability means we can lose a large building or a large line, and we maintain positive control of the grid. That has a very specific definition.

Stability has to do with oscillations and system recovery to steady state following a disturbance. So I think those words are used by general people in a different sense than we understand them in implementing them on the grid.

MR. DYER: Thank you.

As you were saying, you know, as you go through it, the devil is really in the details, you know, and I think that's the real benefit of this meeting, is if we can make sure we've got -- you know, what we're transmitting is what you're receiving and what you transmit, what the licensees transmit back to us is what we receive, you know. It's those kinds of details that are going to be important.

MR. CAMERON: Okay, and thanks, Jennifer. I put common vocabulary in the parking lot, and I'm going to ask all of you to be a guide for me about when is the most appropriate time to address, during the next day and a half, to address those issues, but we do have it in the parking lot.

Yes, sir.

MR. KLECKLEY: Good morning. I'm Phil Kleckley, and I'm in the transmission planning group at the South Carolina Electric and Gas Company.

And while we're talking about definitions, I was going to wait until we had a little more discussion, but maybe this is a good time to go ahead and do this.

In referring to operability of the off-site power supplies, not being a nuclear person, I don't have much of a background in the usage of the term, but in reading through some of the materials, I'm getting a little bit of vagueness in what I'm understanding it to mean.

Does this mean that the off-site power supplies are reliable to the point that it is not necessary to go to the on-site power supplies, or does it mean that if the off-site supplies are lost, they will become available before some other requirement is met?

Thank you.

MR. CAMERON: Okay. I think that I don't know if, Brian or Jim, you want to say anything or Paul at this point, but certainly it's going to be an issue that we're going to come back to later on.

MR. DYER: I think the former. I think the first thing you said, but I --

MR. GILL: Jim, I think I'll elaborate on that when I get it in my discussion.

MR. CAMERON: Okay. Good. So we won't lose that one. Okay. We'll come back to it.

Let's go to this gentleman right here.

MR. ROSENBLUM: Dick Rosenblum from Southern California Edison. I'm the CNO there now, but I used to be the head of the transmission and distribution business for the last ten years.

Brian's comment about negative reserve causes me to ask that people think about one more definitional difference that I think is going to become important, and it's one not commonly made. There's a difference between grid reliability or grid operability or whatever the defined term we choose to use, which for a transmission person means you've got the right frequency, the right voltage, adequate VAR (phonetic) support, and a bunch of other thing.

In-service reliability, a term I have just made up, which means your customers have lights, that's a distinction not commonly made by anybody. Brian talks about negative spinning reserve. The way you get spinning reserve back is you show a bunch of your customers off.

The grid is a happy camper through all of that. So I think as we go forward, and I'm not trying to lecture here; you know, it sounds like it; we need to start differentiating between those two things. The nuclear power plant requires grid reliability. Service reliability is immaterial and is, in fact, used to create grid reliability, and that is a distinction that has not historically been made by either the nuclear people or the transmission people in the way I just described it, but is important to this issue.

MR. CAMERON: Thanks for offering that distinction, Dick.

Anything else before we go on? We'll go right here and then we'll go right over there. Yes, sir.

MR. LEAKE: Hi. I'm Harvey Leake with Palo Verde.

I think the two points that Jim made were pretty important for the industry one. The industry is not asking for an analysis of double contingencies, and second, that there's not a new requirement for use of real time contingency analyzers.

So my question is: is this going to be clarified anywhere in writing?

MR. CAMERON: Okay. Thank you.

And just before you answer that, Jim, I just want to check in and make sure that the two things that you heard are correct assumptions about what you said.

MR. DYER: Yeah, I think we don't require a double contingency, but the one caveat I made was but if you have an off-site supply or a supply to the grid another unit supply -- you're going to get me tangled up now because I know it's probably butchering whatever the vernacular is in the transmission world -- but there's another supply, you know, besides the nuclear plant that will, in fact, take down the grid and cause the nuclear power plant to trip. That would be the largest contingency.

The same thing with the real time contingency analysis. We're not specifying a code, I mean, but I'm glad the Federal Energy Regulatory Commission is here, and my understanding is that the transmission system operators are all using literally state of the art codes for our purposes that can predict or do the kinds of analysis that's needed for the NRC regulatory needs in the utilities.

If we're wrong, then we need to understand that, but I think you're right.

MR. CAMERON: Okay, and the final point, Jim, about whether these issues will be clarified in the generic letter.

MR. DYER: Yeah, I thought they were, but I think there's a footnote on the real time contingency analysis code, and it explains -- it doesn't say we're not going to do double contingency, but it does talk about what we are going to ask for, which is the single largest contingency.

MR. CAMERON: Okay, and that point that you raised is before us, and it's one of the things that the staff will look at after this meeting.

Let's go to Bruce.

MR. POOLE: Yeah, my name is Bruce Poole. I'm from the Federal Energy Regulatory Commission, and I guess what you have to say is everyone is judged in NERC on meeting standards. Okay? And so you always have your contingencies because that's set up in the standard.

Some people run a computer program that does an on-line contingency analysis all the time, but not everybody does that. Okay? So not every utility will be doing that currently. There are some that are developing systems now that will, and there are some that haven't converted or aren't using that.

So I just want you to know that when you say real time contingency analysis, not everybody does that, but they all manage to meet NERC reliability rules by some other method. They may have a program that's not running all the time. It may run every five minutes or every ten minutes. Okay? But it may not be real time.

MR. DYER: I think our main thrust is that when the ISO or transmission system operator realizes or analyzes that there's a problem, that there's communications to the utility and what the utility does with that information.

MR. CAMERON: Okay. Great. Let's go for one more comment/question, and then we're going to go to Paul. This is a good preview and prelude to some of the issues that are important for discussion.

MR. ATTARIAN: Thank you.

George Attarian, Progress Energy and Chairman of Working Group 4.6 on off-site power IEEE.

My question is that in the last three years the nuclear industry has not been, so to speak, in a hole. There's been a lot of things that are happening. What weight did the staff give to the generic letter to the actions that have been taken by the INPO SOERs and the other actions that are in progress right now by the industry?

MR. CAMERON: Great. Thank you.

MR. DYER: From my perspective, I think that you're right. The industry has done a lot; the NRC and the industry have both done a lot to understand what's going on, what the conditions are.

Clair is here from the Institute of Nuclear Power Operations to participate, and he'll be able to shed some light on that.

I think what INPO has done has gone, in particular, beyond, you know, what our regulations are. What we want to know is that the floor is there, you know, what we consider the minimum stuff acceptable.

So it's not our intent to regulate to what INPO is expecting because it goes beyond, but it is a subset or below that that we feel our regulations require to regulate at that level.

And so hopefully, and I've talked to George Fellgate (phonetic) at INPO, and that what INPO is doing would cause the utilities to exceed what we're doing, but we need to know that that floor is there.

MR. CAMERON: Okay. Thanks, Jim, and we do have Mr. Clair Goddard with us who is going to be on a panel tomorrow and will specifically address what the implications are for the generic letter from what INPO is doing, and I'm sure we'll hear about that before tomorrow, too, but I would just thank Jim and Brian for being here this morning, and I'm sure they'll be here as much as they can throughout the next day and a half, but I think we're ready to move on to the overview.

Mr. Paul Gill from the NRC staff.

Just let me ask. Brian, Jim, do you have anything else that you want to say before we go on?

MR. DYER: No.

MR. CAMERON: Okay, great. Thank you.

MR. DYER: I've got to run.

MR. CAMERON: Okay. Thank you, Jim.

MR. GILL: Good morning. My name is Paul Gill. I'm the technical lead on the generic letter, and I'm going to use slides to discuss the generic letter.

Mr. Dyer and Dr. Sheron have already laid out, I think, to a great extent what I was going to talk about. So what I'm going to do is talk in a little more detail of the overview and the reasons that they laid out.

So if I could go to my first slide, please. Go to the next one, Objectives.

Okay. I think you heard the objective this morning from Mr. Dyer and Dr. Sheron, but let me follow up on that. The objectives of the generic letter is essentially one to seek information from you in terms of assessing where we are in terms of meeting out regulations. So there's one objective is to verify compliance.

And the second objective I would say is that based upon that information, to see if we do need to do something different, such as maybe rulemaking, if that is the case.

So we need that information to assess within our agency to find out where we are, and what I want to do also here is to -- my objectives for discussing the generic letter is to provide you what we think is the regulatory basis for asking the questions that we are asking; also to tell you what's intended by these questions, what kind of information we are looking for; and also what we would expect in terms of answers, trying to help you along in terms of what we are looking for rather than send you a very general question and then get responses which may require further elaboration and requests for additional information. So we want to minimize that. We'd like to make it a very smooth transition in terms of getting responses that we understand in terms of what our needs are.

And also how are we going to use this information?

Next slide, please.

We are asking questions. Jim mentioned four areas, but in essence actually, you know, if you got up and looked at it, it's really three areas, although we could make it into four areas. The one is, of course, into the off-site power system, and I'm going to get into the off-site power system to kind of give you the basis, the regulatory basis, and to determine its you heard the words "operability" or "availability," and so on. So I'm going to talk about that as we go through my discussion.

And the second area is the maintenance rule, and again, in terms of using looking at the grid, are you taking the grid into when you make risk assessments? Before you take risk significant equipment off, as well as while you are in the maintenance of that equipment.

And the third area is station blackout,

and I'm going to talk about that a little bit to give you some background, what the requirements were, what your licensing basis is regarding station blackout, and why we think at this time we need to kind of look at it again, given the operating experience as to whether we are still in compliance or not.

So those are the three areas that we're going to look at.

Now, let me go to the next slide, which will talk about the regulatory requirements, and I'm going to go through each area, first dealing with the off-site power system.

You heard mentioned GDC-17. On this slide I've listed the other GDCs, or the general design criteria, that talk about off-site power system, and these other GDCs are the 33, 34, 35 all the way to 44, and they all have requirements for off-site power system.

And let me kind of sort of paraphrase what's in those GDCs and you can look at the 10 CFR 50 and read in more detail.

And what this talks about is -- the next slide -- it talks about the requirements in these GDCs, and these are required for ESF type systems, and it says that for off-site electric power system operation and for on-site electric power system operation, the system safety function can be accomplished assuming a single failure.

What it's saying in these guides, general design criteria, is that you have to have an off-site power system available, assuming the on-site is not available, as well as -- the emphasis being on "and" -- have an on-site power system available assuming the off-site is not available.

And the single failure, of course, applies to the on-site system because we don't take a single failure in the off-site system.

So if you look at these design criteria, it's saying that you have to have both available. So it's not one or the other.

I've heard the argument or discussion from people, well, gee, I got my diesels. My diesels work fine. So what's the problem with the off-site?

Well, the problem here is that if you strictly look at the design criteria, it's requiring that both be operable at the same time. So what we want to make sure is given the operating experience, do we have an off-site system that is operable and available to perform its safety function? Okay?

So that's the regulatory basis for the

off-site power system, as well as if you look at GDC-17.

Next slide, please.

Now, GDC-17, I've kind of pulled out a small subset from the criteria that's listed in the GDC-17 because it talks about the number of off-site power sources into the plant and the design aspects of it, but it also has provisions where it says that you should minimize the probability of losing electric power from any of the remaining supplies, you know, that are coming into the plant to power the safety buses. Okay?

And it specifically talks about loss of power from the transmission network. Now, I've heard the arguments, and I think it will be resolution of comments. I think a number of commenters said, "Well, GDC-18 is only a design guide. Well, that is true, but I will then argue that any design, the adequacy of any design, including the power system, can only be determined by reference to the conditions under which it's going to be operating. Okay?

Now, whether the system meets the design criteria can only be determined by analyzing the system response under the most extreme operating conditions. So what good does it do to have a design that we think is adequate, but when you actually need it, it's not there?

My point being that, sure, there are design requirements, but along with it, you have the operating requirements. Now, the operating requirements are imbedded in the technical specifications. So for those of you that are familiar with the technical specifications for a nuclear power plant, it talks about, you know, the limiting condition of operation should you use one line or two lines. Okay?

So that's what we want to emphasize. That's what we want to find out. Given the grid conditions today -- and I'm not going to argue whether the grid is reliable or unreliable at this point. I think the discussion following my presentation will, you know, make a point that grid, you know, of course, is -- that we see on the horizon some issues with the grid.

The point that I want to make here is are you in compliance with your technical specifications if you know that the grid is not going to be there or the off-site power is not going to be there if you have a unit trip.

I know we had talked about what's a unit trip. In this case it would be a nuclear unit, and so the point being that, you know, are we in compliance or not. Are you meeting your licensing basis or not? Are you meeting the tech spec or not?

So the regulatory basis for the Questions 1 through 4 that are in the generic letter basically are based upon the GDC's criteria, the technical specifications that, you know, are part of your licensing basis. You know, I'm talking about the nuclear power plant licensees now.

Okay. Let's go to on the next slide, and I will come back and talk about, you know, in a little more detail the off-site power system when we get to the questions.

Now, let me just come back to the off-site power system. I forgot about this slide. If you look at this slide, we talked about this RTC, real time contingency analysis, and so on.

Now, let's go back to the bold where the 4(d) regulation. Okay? All the utilities were vertically integrated utilities. The transmission folks were part of the same group that were the nuclear unit or the fossil units. They all talk to each other openly.

And one of the licensing bases or one of the criteria that if you go back and look at our standard review plan, NUREG 800, Chapter 8, it lays out very specific evaluations that you have to make for the off-site power system, and it talked about this contingency analysis. Okay?

And here Jim talked about single contingency versus double contingency.

Now, if you review your, say, licensing basis, you'll find in the U.S. FAR that the analysis that you perform at that time during the license was to look at three areas. One was the loss of the largest single supply, and in most cases it most likely is going to be the nuclear unit, or it could be some other unit that is even larger than the nuclear unit.

You have to assume that failure of that unit and show that the off-site system is available and functional. Okay. I'll use those words instead of being "operable," or you look at the most critical transmission line and assure us or assure yourself that there's adequate voltage or adequate, you know, power available to power the safety buses.

And the third criteria was the largest load, that if you lost the load rejection, for example, that you still would have off-site power.

Now, the question in terms of being available, operable, or functional, what we have to look at is for most plants today we have the degraded grid wall ditch (phonetic) set points because that's what's going to cause you to lose off-site power or going to cause you to lose power to the safety buses. Because if your voltage dips below the degraded grid wall ditch set points, you're going to lose off-site power.

So the real key issue from our perspective is do you have adequate voltage in the switch yard, which is the off-site power system, to power the safety buses?

So that's one simple way of looking at or assuring adequate off-site power system. Okay?

Now, let's go to the slide that talks about the maintenance rule, and, Steve, thanks for coming, for answering any questions on the maintenance rule since I'm not an expert in that.

The maintenance rule requires under (a)(4) to perform, you know, risk evaluation or do a risk evaluation before you take equipment out of service, and it was alluded that now we are doing a lot of maintenance at power. For example, diesels from three days Dr. Sheron mentioned, and now we have going to 14 days when the unit is at power or when the nuclear power plant is supplying -- the grid is supplying power.

And the question is that you need to look at the maintenance. You have to look at the -- before you take that diesel out or any other what we call risk significant equipment out, that, indeed, the grid risk is factored into your risk evaluation, not only when you go into the maintenance, but you should also, you know, keep on top of it while you're maintaining it to see if conditions change.

So that's an area where we have, you know, questions. We want to have some information. So we can better understand how you are implementing that provision of the maintenance rule with respect to the off-site power system.

Next slide, please.

Now, in the station blackout area, if you look at the statement of considerations, the EDG or the emergency diesel generators, which are the on-site power sources, its reliability or -- I'm sorry -- its availability was considered to be very, very low, and that was based upon only looking at the corrective maintenance that was done at power for the emergency diesel generators. And as indicated here, it was less than one percent.

Now, in terms of station blackout rule, the target reliability that is factored into the rule is either .975 or .95.

Now, you know, this low availability that was assumed in the station blackout determined those targets. Now, what if your current unavailability is, say, three percent or something different? Then you say, you know, the question is going to be how are you meeting your .975 reliability target if your diesel is not available to you for three percent.

So that there's a concern now that not only the diesels that you have. You're taking them out for ten, 14 days, say, during a refueling cycle and doing maintenance at power. What is the real unavailability of those diesels?

And as I understand it, and somebody can correct me, that according to the industrial guide, preplanned maintenance unavailability is not counted into the overall unavailability of the diesels. So it would seem to me that perhaps the unavailability will be something that if you factor that in it might be even higher than what it is being reported.

I think I'm going to take a little bit of water. My mouth is all drying up.

And also under the station blackout rule, the assumptions that we made, for example, to determine the coping duration, and again, the station blackout rule is not a very easy rule. It's very cumbersome, and in the sense that before you determine your coping duration you have to go through a lot of analysis of calculations.

And one of the items in determining the coping duration is looking at the off-site power characterization. Let me put it that way. In other words, you look at the off-site power system and determine what kind of off-site power system you have. In the station blackout rule, it gives you three grades: P-1 through P-3. In other words, from the very best to the very worst, and based upon what group that a specific site or plant fell into the off-site power group determines, along with emergency diesel generator reliability target that was chosen, as well as, you know, some other factors. You determine what would be your coping duration.

That is, that if you had a station blackout, for how long would it take for you to recover off-site or on-site power? So that is a coping duration that you have to maintain the plant in safe shutdown condition.

And most of the plants according to station blackout rule either fall into four hours or eight hours. So let's assume that you have a plant that has a four-hour coping duration, and its original determination was made upon the off-site power group being either P-1 or P-2, and the question that we are asking in this area is based upon the operating experience, given the loss of off-site power events which you will hear later on about, what if you now become a P-3 group? What would be the coping duration?

And if you look at the guide, the Reg. Guide 1.55 or the NUMARK (phonetic) 8700, you're coping duration might be higher than four hours. It may be eight hours or 16 hours.

So given that, now the question is that from our perspective is the four-hour coping analysis adequate to keep that plan safe if you don't expect to recover that off-site or the on-site, you know, either from four hours to eight ours.

Now, for four-hour plants, the majority of them depend upon natural circulation. So the analysis has been done for those plants that are four hours using the natural circulation, that they have enough water. Okay? They have enough battery for four hours.

So now from the staff's perspective, what if your duration became eight hours? Do you have enough battery? Do you have enough water?

And I don't think, you know, we can sit back and say, "Gee, everything is going to be all right." Maybe it would be all right, but I think the question needs to be answered, and we have to ask this question: that if, indeed, your original coping duration is still being maintained, if it is, then your analysis is okay. And if your coping duration is now changed, then you need to ask yourself, you know, do I need to do something different now.

So that's where the questions in the station blackout area are being driven from. Now, we are concerned that if your coping duration changes or increases -- let me put it this way -- then your current analysis is no longer valid, and you need to, you know, tell us one way or the other whether it is or not.

But the first step you have to do is to determine whether your coping duration is impacted or not. Okay? So that's a real safety concern there.

All right. Chip only gave me what, about 45 minutes to an hour? So I need to move fast here.

Let's go into the generic letter itself and talk about some of the questions and hopefully later on in the workshops or in the clarification period we can answer some of your questions.

In the first area, off-site power, there are four questions as I mentioned, and those four questions basically go:

Question No. 1 goes to the agreements with your transmission system operator or your ISO, since various terms are being used, for monitoring off-site power. That's kind of the handshake arrangement that we are asking you about. What kind of arrangement you have with your transmission system operator in terms of communicating with him, or the transmission system operator communicating with you about the grid.

Now, as I mentioned earlier, your licensing basis established the contingency analysis that was done during the license. That is your licensing basis.

Now, as we know, today many of the transmission systems are separated from generation or even for those utilities that have not gone to deregulation, I believe your generation is separated, although be part of the same company.

Now, as I understand it, the grid is being operated -- let me put it this way -- in a different manner than was originally envisioned. As I said, in the old system, you did a contingency analysis, and you operated the grid within the bounds of that contingency analysis.

Today I don't think we can say that definitively, that the grid is being operated within the bounds of that contingency analysis. Well, that's the question we are asking you. You need to tell us whether it is or not.

Now, remember the old contingency analysis assumed, you know, the flow, okay, megawars, megawatts, whatnot, how many lines and so on. Maybe physically nothing has changed, but certainly I think you will agree the flows have changed, and if the flows have changed, your analysis I would think changes, and that was the case at Callaway back -- what was it? -- 1999. They had excessive flows through their system which were not part of, originally analyzed. Now, the question is where else is this happening. We know that, you know, of course, the famous blackout. I won't go there.

But the question that we want to know, and I think rightfully so, we need to ask you that is your grid being operated within the bounds of your analysis, or I could put it another way. Is your analysis still valid?

And you need to tell us whether it is or not. And we talked about the programs or, you know, the tools that are available today. Mr. Poole mentioned that some utilities are using, you know, these tools; some are not. But even if you don't have on-line tools for a given, say, plant, that if you're using off-line tools, that you can periodically look at different scenarios or your transmission system operator will look at, you know, different scenarios and operate the grid, and I assume that that's what they're doing, is operating the grid within the bounds of that analysis.

The real question is: does that now match up with the licensing basis type of analysis that was done during, you know, the original license?

So the first two questions for the off-site power system deal with those two areas. One is, you know, communication with your transmission system operator. Second is what kind of tools is your transmission system operator using, and how often it is updated.

How often is communicating to you as a 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 the reactor.

And I could have very well said trip of the reactor or a critical transmission line or largest load rejection. But our focus was that we believe that the nuclear unit or the nuclear generator probably is most likely the largest generator on the system, and what we want to know is if that generator is providing support to the grid for maintaining that voltage, now if that trips, are you still going to have adequate voltage, you know, in the switchyard to power the safety buses?

Now, if you don't, if the voltage is not adequate, your degraded voltage relays are going to isolate or trip the off-site power and go on to the emergency diesel generators.

Now, you know, if you've got both diesels ready and available, great. Okay. That's what we want, but what if you have a diesel on the floor, you're doing a major overhaul, and the other diesel fails to start and you've lost off-site power?

Now you're into station blackout, and I don't think we want to go there. Okay? Now, I hear arguments. "Yeah, we've done analysis. We're okay for station blackout," but I don't think, you know, we want to force, challenge our systems through where, you know, something might work, might not work. Okay?

So the first question basically is saying in terms of these agreements that you have with your TSO to let you know when things are not so good on the grid, as well as for you when you're taking something out when it might impact the grid. So it's a two-way communication. Although we don't have any -- we can regulate that as I understand it, but certainly we can ask the question what are you doing as a nuclear power plant operator to keep on top of this, meet your licensing basis.

And this particular question has -- now we could have left that question as a general question and gotten responses, which may or may not have been adequate, and then we would have to go out for a request for additional information. So we decided that it would be better and more effective in terms of asking you very specific honed questions in terms of what information we're seeking.

So that's why you see these subparts to these questions. We have broken each question down in terms of the information that we want you to send back to us.

So we will ask the question: was the required notification timed for example, that if your transmission system operator, you know, whatever tools he's using, determines that the grid is in stress condition, how long does it take for him to let you know?

Okay. And how often does he do that or how often do you check with your transmission system operator?

Okay. So those subpart questions are essentially to help you and help us get the information from you that we need.

Now, the question is that if you don't have any of these arrangements with the TSO, then one of the subpart questions is tell us how do you think you're meeting your licensing basis if JDC-17?

So you know, you might think there are a lot of questions, but actually many of these questions are very simple, straightforward answer and this was essentially to make it more efficient for you and for us to get the information.

The question as I mentioned talks about the tools. How do you insure that the off-site system will remain operable following a trip off your unit or nuclear power plant?

And we are not mandating. You know, you used the reliably centered -- I mean, these modern tools, real time contingency analysis and so on, but given that your grid is changing, let me say hour by hour or maybe day to day -- I don't know. Okay? It depends on what part of the country or what part of the grid you are associated with -- that if you don't use these tools, and I'll just throw this questions up to you, tell me how you're going to find out what's happening on that transmission system. That is now supplying power to your plant.

Now, you know, I think it seems to me that if the grid conditions are changing, then you have to use a tool that tells you what's going to, you know -- or get heads up as to if type scenarios, that what if I lose that unit or if I lose that transmission line, what's going to happen?

And from a nuclear power plant operator perspective, you know, you would want to know. Do I have that off-site available to me or not?

Now, remember in the context of off-site power we always refer it to as preferred power. That is the most reliable preferred power source that you can gave for the nuclear power plant.

Now, if that is not going to be preferred in the sense that it is not -- you know, again, I'm kind of a "what if" type of conjecture here -- if that power source becomes unreliable, then maybe we ought to start thinking in terms of, gee, we can rely on the off-site power. Maybe we ought to look at something different. You know, maybe we need to go to another power source that we can rely upon.

So it seems to me that, you know, in the resolution of the comments I saw a lot of questions about, you know, RTCA. You know, it's not required by your regulations. Sure, it's not required by regulations, but tell me how you're going to do it. Okay? I'll throw it back at you.

You know that your grid, for example -- and, again, it may or may not be true in every case -- your grid is not being operated in the manner on which your license is based, and I went through the licensing basis.

Now, you tell me: is the grid being operated in the bounds of that analysis that was submitted to get the license? Okay, and it appears to me that the only way you're going to be able to do it, that your TSO has to use these tools either on line or off line, and we're not fussy about which, you know, whether you do it on line or off line, but you need to assure yourself and us that, indeed, you're meeting your licensing basis. Okay. As simple as that.

Now, if you're not using any of the tools, if your TSO is not using any of the tools, then tell us how you're meeting, you know, -- you know, how do you assure you have adequate and reliable off-site power system?

So the questions are basically focused in that area, and we can, you know, talk more about these questions if need be.

And the third question talks about operability determination for post trip, and that would be slide number 18, please, and let's go to the gist of the questions on 19 and 20. I'm sorry. Just 19. That has six subset questions.

Voltage inoperability triggers. In other words, we want to know what triggers do you have in terms of that you don't have adequate voltage in the switchyard?

And it talks about double sequencing operability. This is not the double contingency that Jim was referring to.

Now, as I understand it, you may not be licensed to double sequencing, you know, type of scenario. It assumes that you have a trip of the reactor and your off-site power is still there and assumes that you have a LOCA at the same time, but if you have a LOCA you have a unit trip.

And it assumes that you still have power. You haven't lost the off-site power. So to meet mitigate LOCA, you're going to have to sequence on all the safety equipment that you need.

Now, the question is: what if you lose power, delayed loss of off-site power? That you lose off-site power some time into when you are sequencing on the safety equipment.

And I think this issue has been discussed with the industry, you know, over the years, and I don't think you reached any conclusions on that as far as I know, but we are asking that question: have you thought about it? What if you lose off-site power now? Are you now going to, you know -- you know, is that diesel that comes on, is going to now block load or is it going to -- or some other, you know, safety equipment fails -- have you looked at in terms of those type of scenarios?

And tell us, you know, what's the outcome and if you, you know, declare that equipment to be inoperable if that should happen?

Okay. So that's kind of a, you know, "what if" scenario that you lose off-site power at some time later than when the reactor trips.

And of course, in all of these questions, we are asking, you know, training and procedures. Do you have adequate procedures and training for your operators? I think that's a very important one.

And the fourth question in that area is tech specs require that plant's off-site system be operable as part of the plan limiting condition of operation. So if you are familiar, for those of you that deal with tech specs, you will find that it has, you know, allowable values. These days we are changing from the actual trip values to allowable values, and we are looking at or we are asking you, you know, do you have any guidance in place that alerts your operators in terms of the set point trip values as well as on-site equipment, such as voltage tap changing, you know, transformers or some of the voltage control equipment that you are using within the plant or within the switchyard that helps you maintain that voltage or the operators are, you know, familiar with it, trained in it, you know, in that equipment. Okay?

And so those are the questions that we are asking in the off-site area, in the four areas, and as I said, the reason why we kind of made it into four questions was to help you, you know, understand and also to focus on the type of information that the staff was looking for or is looking for. Okay?

Let's go to Slide 22 and 23. More onto the risk area. Under (a)(4) you're required to evaluate off-site power system or include it in your risk evaluations.

The questions that deal in this area is input into the risk assessment. During the maintenance are you monitoring the grid? The question came up about seasonal variation. I think according to our maintenance rule experts, yeah, you're not required to do it, but wouldn't it be nice to know what you're doing and when do they occur. Are they in the summer months, as we think it is, or are they in the winter months?

You know, depending upon the geographical area that you're in your seasonable variations that impact the grid might be different. You might have a winter peak rather than a summer peak.

So those are the questions that we, you know, are asking in that area. In terms of the seasonal variation, do they impact your loop frequency? Okay?

And then also this goes back to the communication between the TSO and the nuclear power plant operators. If they find things, you know, that are becoming stressed on the grid, how long does it take for the TSO to inform you or do you make periodic checks with the TSO to keep on top of it?

And you know, for us to think that, gee, I'm just going to sit here and wait for the TSO to tell me, that may not happen. So I think, you know, we need a very smooth, very effective, you know, communication type of agreements or protocols or whatever you want to call them between the transmission system operator and the nuclear power plant operators.

And then there's the second question that deals with -- it's how are the results of the maintenance risk assessment included in the results of the grid stability evaluations used in managing risk?

Okay, and this has nine subparts to it. Again, you know, dealing with the maintenance and the communication with the TSO.

Okay. Let's go to Slide 28 on station blackout.

Now, for station blackout I mentioned about, you know, how we arrive at the coping duration. There's a very cumbersome process to go through to come up at the coping duration. Now, the regulatory guide that addresses station blackout is 1.155, and the complement document or the industry guidance is NUMARK; I believe now might be NEI 8700. I don't know how they numbered it. But those were the two documents that were used for implementing station blackout rule.

And if you examined the Reg Guide 1.55, Section 2 that talks about off-site power and the NUMARK 8700, Section 4.3.2, those two sections or those sections in the Reg. Guide and the NUMARK very specifically talk about having procedures for restoring off-site power and the use of nearby local power sources.

The question we are asking in that area is I believe that from our feedback from the TIs, that either all or the majority of the plants have procedures for restoring off-site power. What we did not see is that the use of nearby power sources -- and they are defined in the reg. guide as to what they are, and also in the NUMARK it talks about local power sources such as the generators or black star diesels and so on, and it also talks about in the NUMARK that you should coordinate all of this with the load dispatchers.

Okay. In the old days we did not use this fancy term about transmission system operator. The transmission system operator was basically a load dispatcher. The guy that controlled the transmission system.

So now if you don't have the communication, you know, agreement or protocols in place with your transmission system operator, the question that we want to know is how are you now going to implement this feature of using the local power sources. Have these arrangements been carried through from the old system to the new system or they've kind of just fell off the deck?

Okay. So we want to know, you know, where are you, you know, for your specific plan. Have you carried that, you know, feature across from the old system to the new system, and based upon the answer, you know, then we would evaluate it and see what we need to do.

The other question that we are asking is about the loop frequency or loss of off-site power due to grid related events. In the station blackout, they looked at loss of the off-site power due to many, you know, in plant type of losses or losses due to the in-plant type of equipment failures, loss from the sweeter weather (phonetic), extremely sweeter weather and so on, and also looked at the grid related losses.

Now, given that we've had some loops, and again, that's a question for debate. I think you will hear both sides saying, now, the industry is probably, EPRI is probably going to say, well, you know, we haven't had that many or haven't had any. Staff is going to show you differently, I think.

But leave that aside. The question that we want to know from our electrical area in terms of implementing the station blackout rule, that if your frequency has changed due to grid related loops, how is your impact duration?

Okay, and I talked about that. What if you go from four hours to eight hours? Okay. Now, it depends on the answer, that if you're still four hours, you have analysis that shows the plant is going to be safe for four hours, but should you now go to eight hours, your old analysis is no longer valid.

And we need to ask that question because, you know, we can't sit here and get a warm feeling that everything is going to be all right if, indeed, you're coping duration has changed. Now, we can argue whether, you know, what are grid related losses and so on, and I think with some plants we've argued that back and forth, but we need to ask you that question, and it's a very serious question in the sense that let's not fool ourselves. If, indeed, your coping duration has changed, you no longer are meeting the station blackout rule.

Okay. Because if you get to station blackout as I kind of told you, you know, with one diesel on the floor, the other one doesn't start and you've lost off-site power; you are in station blackout. Now, the worst thing is that if you don't recover within the time period for which you are licensed, you've got a very serious safety issue because you're going to run out of battery; you're going to run out of water. Okay? And you know, you're going to have serious consequences.

I think with that, I'm kind of done.

MR. CAMERON: Okay.

MR. GILL: I don't know why my mouth is drying up. Maybe I'm nervous, right?

MR. CAMERON: thanks, Paul. That was a pretty comprehensive overview of the generic letter, the regulatory requirements, the assumptions.

We have a few minutes for questions and commentary. Keep in mind that all of the questions are going to be addressed in detail by the panels, and Paul is going to be here as a resource on that.

Perhaps questions, he went through the regulatory requirements. Maybe questions on the regulatory requirements or assumptions that the NRC is basing the GL on might be appropriate at this point.

Let's go to Alex Marion. You're going to use this? Okay, great.

MR. MARION: Alex Marion, NEI.

Point of clarification and a couple of other comments. Mr. Gill, in your presentation you talked about the off-site power characterization that's used as part of the station blackout coping analysis, and that's the P-1, the P-1 category, and if I understood you correctly, you indicated it goes from the very best to the very worst, and I'd like to clarify that.

MR. GILL: Well, what I was saying was --

MR. MARION: The categorizations represent the configurations of off-site power for the U.S. plants.

MR. GILL: That's right.

MR. MARION: Not necessarily quantifying good, bad, or indifferent.

MR. GILL: I was probably using -- just to make my point, if I have three categories, P-1 to me is the best. P-3 says if you're in P-3, you have the worst off-site characterization of the off-site power configuration to your plant.

So if you will indulge me, in my passion I say that's the worst. Now, I'm not saying that in a derogatory manner. I'm saying in a very relative term, going from the very best to the very not so best.

(Laughter.)

MR. GILL: If that's what you like. I mean, you know, I'm about semantics here.

MR. MARION: Since this is being transcribed, I want to make sure the record is clear.

MR. GILL: Sure, no.

MR. MARION: And they do represent the off-site power configurations for plants who were licensed by the NRC.

MR. GILL: That's correct. I'm not saying that's not acceptable.

MR. MARION: Now, the methodology, the methodology plays out a process where you're penalized, if you will, for certain configurations. That's part of the process.

MR. GILL: Right.

MR. MARION: And I respect your opinion. You did make a couple of comments that some of the information that's being requested is not required, and I agree with that.

You also clearly in the generic letter, the basis for requesting the information is to obtain information to make a decision on the operating license of a plant under the provisions of 50.54(f).

Just a comment, again, for the record. Sine the subject of the questions are not required, then how does 50.54(f) play out since they're clearly not in the licensing basis of the plant? And that's a subject we can talk about for hours, but I just want to put that on the record.

Lastly, there's a new provision or a new portion of the proposed generic letter that's different than what was released for public comment, and that deals with training. Given that that was added and the public stakeholders did not have an opportunity to comment, could someone explain the rationale for not putting it out for comment or at least seeking stakeholder comment on that particular area?

MR. CAMERON: Do you want to address that last point?

MR. GILL: Well, the last point in terms of adding the training procedures and training, the

Commission issued an SRM, the same SRM that it asked us to issue a generic letter, had a provision in procedures and training. If I can be up front about it, we kind of missed it, and then when we discovered that it needed to be done, so we included that.

It was cleared with the Office of General Counsel. They said we didn't have to go back out again for re-comments, that we could include it in the generic letter.

MR. CAMERON: Okay, and I guess the bottom line here is, as you heard Mr. Sheron talk about earlier, this is not meant to be a reopening of a comment period, but anything that you say during the next day and a half is going to be looked at by the NRC staff. So I guess the most important thing is if there are substantive issues related to the training procedures, raise them during the next day and a half so that the staff will have the benefit of your comments.

In terms of the last point before that that Mr. Marion raised in terms of the 50.54(f), Paul or Brian? Brian.

MR. SHERON: Fifty, fifty-four (f), you know, as you know, it allows the staff to request information. I think the words are to determine if we want to suspend, modify, or whatever your license. Okay?

We use that as an opportunity to gather information if we believe there is a safety concern associated with principally compliance. We can use it for two reasons.

One is we can gather information to determine if we need to change our regulations. In other words, if we are seeking information to determine if our regulations are inadequate, you know, we need to, for example, promulgate a new regulation or in this case, we determined that we believed our regulations were adequate and covered the situation that we're dealing with, but it raised -- the situation raised questions about whether we had assurance that compliance was being achieved.

And you know, we use the generic letter. Again, what's in the generic letter, what is requested, as Alex said, it's not a requirement or anything. What we're doing is we're saying that this is what we think would be sufficient to demonstrate compliance. We're trying to help the industry to some extent. We're telling you what we would accept.

And if a licensee comes in and says, "Yes, we're doing this. We have these protocols with our

TSO. You know, we take a look at risk or grid reliability when we go into a maintenance outage or whatever," you know, then we would probably find that acceptable and say, "Yes, you know, we're satisfied you're complying with the regulations."

Now, if you don't want to come in and say, you know, I agree with the NRC and am doing all of these things, then you want to know what you are doing. Okay? You know what the underlying concern is. So you need to tell us what provisions you've put in place to help us provide that assurance.

We will evaluate that and, you know, I'll be quite honest. You know, if we don't find it acceptable, then we'll decide what we have to do, whether it's a plant specific backfit or not.

You've got to remember a lot of times people always say, "Well, why don't you just backfit?"

Well, we could do that, okay, if we had perfect knowledge and we knew that every licensee was definitely not complying with a regulation. But we don't know that, and we'd like to give the industry the benefit of the doubt, and that's why we go with the generic letter, and that's why it requests information that says we don't think you're complying or we think there's a compliance issue here. We need more information before we can make a decision. Okay?

We're not at that point where we can just say everybody has to be backfit and do the following. We want to give you an opportunity. If you have other information that says, you know, "Well, look. I don't have this specific protocol or whatever with my TSO, but this is what I do have," we'll evaluate it, and if it makes sense, then that's fine.

But that's the whole purpose of a generic letter, okay, is we explain what our concern is, what the safety concern is. We give you an opportunity to either tell us what you are doing, why you don't think it's a concern, or as I said, we try and be helpful and say this is what the NRC will find acceptable, and if you want to do it this way, then you know, you can commit to it and, you know, we'll all move forward.

MR. CAMERON: Hey, thanks, Brian.

Alex, Brian put a finer point on the 50.54(f) issue. Do you have anything else that you want to say on that before we move on?

MR. MARION: Alex Marion.

Our comments that were submitted on the draft generic letter, I think, contain all of the details.

MR. CAMERON: Thank you.

Dick.

MR. ROSENBLUM: Thank you.

Dick Rosenblum from Southern California Edison again.

I get a little confused both when I read the generic letter and when I listen to various people from the NRC discuss this about what the NRC expectation is concerning the interface between the nuclear power plant and the grid operator, transmission operator in this respect. Hypothetically if the power plant were designed appropriately and operated appropriately to GDCs and station blackout rule, et cetera, et cetera, and if the grid operator used whatever interface criteria were in an agreement between the nuclear power plant operator and the grid operator to notify the plant operator any time those conditions weren't being met; so you've got a clear interface requirement, all the criteria are adequately assessed and known, the grid operator operates the grid. Any time you are outside let me just say acceptable operating space on the grid, they call the nuclear power plant operator and let them know.

Is that acceptable, or do you have to have that, which is sort of Question 1(a), and 1(b) which says, "And, oh, by the way, periodically talk to your grid operator above and beyond that," because that's very unclear and it permeates this discussion.

If you have acceptable operating interface requirements, is it okay for the grid operator to operate and let you know when those are no longer being fulfilled, or do you somehow have to do more than that?

MR. CAMERON: Okay. Thank you, Dick.

And I think the question is very clear. Paul, do you understand the question, Paul?

MR. GILL: No, I understand the question, and again, I don't see where the confusion is coming from. What we are asking is that, yeah, as I explained, there is a licensing basis. There is a -- you know, for the off-site power system. Is the transmission system being operated in the confines of that analysis?

Now, if it is not, then the TSO needs to tell the nuclear power plant operator that if I lose, say, a nuclear unit or lose a transmission line or whatever, then you're not going to have adequate voltage. He needs to communicate that to the nuclear power plant operator.

MR. CAMERON: And, Dick, let me make sure you're on the record. No, don't worry about that, but

I guess the question you had is if there is an existing protocol that will cover when the TSO has to communicate, et cetera, et cetera, is that sufficient or is there something over and above that that you need to do?

And based on what you have heard from Paul, is there still an ambiguity there?

MR. ROSENBLUM: Well, I fully understood the answer, but it seems as I listen to the discussions and as I read the generic letter to be inconsistent with some of the assumptions underlying some of the questions in the generic letter, and that's why I thought that seminal issue needed to be resolved.

If that interface criteria, assuming everything is appropriate, and notifications across that interface criteria are necessary and sufficient and you need do no more than that, then the clarity that that is necessary and sufficient is very important to us.

MR. CAMERON: Okay, and I guess that one of the objectives of the generic letter might be for the NRC to determine whether that arrangement is necessary and sufficient, and if it is necessary and sufficient, is that the end of the question?

Paul, do you have anything?

MR. GILL: You know, again, as I said, unless they just want to talk. I mean, the nuclear power plant operator needs to know when that transmission system, the basis for having reliable off-site power is outside the bounds of that.

MR. CAMERON: Is some of the information that's given to us in response to the generic letter if the operator, the licensee, rather, said that we think that our arrangement is going to provide us with everything necessary and sufficient to address these concerns, then that would be something that would be useful to know.

Brian? Okay. Let's go to Mike, and I forgot that Steve Alexander, our maintenance expert, had one caveat that he wanted to add to Paul's presentation, but let me go to Mike on this issue.

Mike.

MR. MAYFIELD: Mike Mayfield, Director of the Division of Engineering at NRR, and this generic letter is coming out of my division.

So at some point I'm the one that everybody seems to be steamed at.

(Laughter.)

MR. MAYFIELD: I think as Jim Dyer opened this up this morning, part of what we're willing to do is see if there are areas we need to clarify in the generic letter. This strikes me as one that we don't want to get out today and give you an answer. It's a fair question, and it's plainly something we need to go back and be real clear on in the generic letter.

So that's the commitment you'll get, is we'll go back and look at the way we're posing the questions and the background information, and hopefully we'll make that real clear as we go forward.

MR. CAMERON: Great. Thank you for that comment, Dick, and leading to clarification that the staff is going to take a look at.

Steve, did you want to add anything to Paul's presentation on maintenance? Go ahead.

MR. ALEXANDER: Steve Alexander.

The new name for our reorganized branch is PRA Operational Support and Maintenance in the Division of Risk Assessment, and I had some input into the generic letter in the maintenance rule area.

And just a couple of clarification. People talk about simply taking risks equipment out of service prior to maintenance. The maintenance rule, Paragraph (a)(4), talks about maintenance activities, and that's a little bit broader definition.

And so what we did is in the generic letter we coined a term "grid risk sensitive maintenance activities." So it's important to keep in mind that those include three categories of things.

One is maintenance activities that could cause or require a plant trip or a plant shutdown, and to clarify a question we had earlier, you know, once a plant trips for whatever reason, it doesn't have to be for a design basis accident. You still have to remove decay heat, and so the unit trip for whatever reason is going to be affected by the availability of off-site power.

And so that's one of our categories of grid risk sensitive maintenance activities. So that's, again, anything that could cause a plant trip or could require a plant trip or plant shutdown.

The second is anything that might cause loss of off-site power for no other reason, just because it could cause a trip in breakers in the switchyard. So switchyard maintenance might be an example of something that could be grid risk sensitive, because it may cause you to divorce from short power, to use my old life here, and therefore, affect the availability of power for safety buses.

And the third category of grid risk

sensitive maintenance activities that we talk about are those that could affect the ability to cope with a loss of off-site power or station blackout. So you kind of are trying to maintain when we're thinking about this the big picture of all three of those types of maintenance activities that can affect maintenance risk, which is what Paragraph (a)(4) requires you to assess.

And even though it doesn't specifically require formal agreements with the transmission system operator, in fact, there's no documentation requirements or procedural requirements whatsoever, and also because it doesn't require things like RTCAs, but what we want to know with respect to the maintenance rule is because we believe that off-site power availability, reliability, stability, all of those things are an external condition that affects plant risk, therefore it should be taken into account in the assessment; we also think that in order to do a meaningful grid reliability evaluation as part of your (a)(4) risk assessment, you need to be able to communicate with the TSO, and so we'd like to know is that being done and how it's being done just to provide some reasonable assurance and expectation of consistent compliance.

Thank you.

MR. CAMERON: Thank you very much, Steve.

Let's take a couple more questions. We will be going back through these issues. Let's take a couple more because we're headed for a break time, and let's go to this gentleman right here. Yes, sir.

MR. THORSON: Yeah, James Thorson, Detroit Edison.

I had a very specific, I guess, question and possibly a comment with respect to the RTCA programs. The generic letter in question, 2(f), asks about nuclear power plant actions with respect to when the TSO might notify the nuclear power plant on the loss of their RTCA capability.

And I guess my question is: what was it that caused the NRC to try and put the onus on the nuclear power plant to produce an operability determination upon the loss of an RTCA, which will be very difficult for the nuclear power plant to do without the same tools as a TSO? Why did it end up in that category rather than perhaps over in the risk area, which may have been a little, at least in my opinion, you could recognize perhaps that you were in a state of increased risk as opposed to a state of needing to determine operabilities?

I was just curious what caused the balance to shift towards operability as opposed to a state of increased risk.

MR. CAMERON: Paul.

MR. GILL: I guess the way I would answer that question, what it's asking is that if your TSO does not or loses the RTCA program, for example, he has no way of now looking at the grid or transmission system to see the status in terms of meeting the NPP requirements.

Remember, I talk about the licensing basis. For example, if he doesn't have the RTCA, you know, for a unit trip, for example or critical transmission line, he has no way of knowing that you're going to lose off-site power at the nuclear power plant.

So the question that we are asking is that if he does not have the RTCA, therefore you don't have the information that if the reactor trips you're going to have adequate power in the switchyard or adequate voltage. Let me put it that way.

Now, if you don't have adequate voltage, then the question of operability comes in. For example, if the unit trips or reactor trips, your voltage goes down below the degraded grid voltage set point. So you're going to lose off-site power to the safety buses.

So now the question is one could pose a question, is your off-site system operable under those circumstances or not?

MR. THORSON: (Speaking from an unmiked location.)

MR. GILL: No, but your TSO should be able to communicate to you and say, "I don't have the RTCA program available to me," to tell you that your system is going to be -- everything is fine. So as a nuclear power plant operator, you have two choices. You could just sit there and do nothing or declare off site unavailable, for example.

MR. CAMERON: Okay. It sounds like this is --

MR. GILL: You know, you --

MR. CAMERON: It sounds like this question is raising a lot of concerns, and I'm going to put this question in the parking lot right now, and we'll come back and explore it because it seems like it's a big issue. Okay?

MR. GILL: All the question is posing is it says when you get such a notification, okay, do you conduct an operability evaluation or not.

MR. CAMERON: Okay. James, we're not getting you on the record here, and I am going to put this in the parking lot because it sounds like there's several of your colleagues who also have a concern her, and we are going to be -- I'll check with the staff in terms of when the best time to discuss that is.

So let's take two more comments now and we're going to take a break, and we're going to get to everybody, but it just won't be right now.

Yes, sir.

MR. MOIENI: Parviz Moieni from the PRA Group. Oh, sorry. I thought I was speaking too loud. Parviz Moieni from the San Onofre PRA Group.

I'm glad Steve Alexander is here so he basically will have an answer for me.

When you look at the generic letter, the grid reliability evaluation has been mentioned a lot, and of course, RCTAs have been mentioned a lot. Grid reliability relation, I hope the staff basically realizes what that means, and it basically clarifies the term very well for the PRA engineers because, as we know, when we do the PRA evaluations or risk evaluations for (a)(4), we go back to our PRA, and we 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 that when we sell our fossil plants, the blanket start capability or reliability is pretty high.

So we had to do a study basically for consideration San Onofre blanket start units, San Diego Gas & Electric, even consider the Hoover Dam for some other power sources.

Believe it or not, it took us about three months, and a group of like ten engineers, some from the grid operators back then or grid control centers, to come up with a reliability of the blanket start because we went outside the switchyard. We considered the grid, other sources.

So it's not an easy task. I don't think when we want to do basically a weekly control evaluation or equipment control evaluation to consider the grid reliability in the sense of grid reliability. So it's very important. The generic letter, I think, redefines what we mean by grid reliability, how we translate or correlate the grid reliability, grid conditions to grid reliability.

Right now if you ask us, we say, yeah, we basically have some conditions that raises the loop frequency and duration for certain conditions, but is it a real time? No, it's not a real time because we don't know how to do it.

So I hope that this would be basically clarified. Otherwise I think the answers would be yes or no. So I don't think we would basically give very exact answers because we don't know. At least I don't know how to do it.

Thank you.

MR. CAMERON: Okay. Did the NRC staff note that request for a clarification on grid reliability?

And, Steve, if you're going to say something on that, I guess try to make it quick.

MR. ALEXANDER: I can't address his question with respect to the entire generic letter, but with respect to the maintenance rule area, those of you who are familiar with Paragraph (a)(4) of the maintenance rule realize and are also familiar with the way that we have inspected and enforce those area of the last five years we don't expect that every external condition or event be quantitatively analyzed and evaluated. We recognize that it is difficult, in some cases impossible for people to do quantitative analysis of various external conditions, including grid reliability or availability or conditions.

And so what we expect as far as maintenance rule compliance is that you recognize that under some conditions there may be increased plant risk. If you can't quantify that, it's going to translate, as you said, basically into additional risk management action, some of which involved making decisions on what kind of maintenance you're going to do.

So to comply with the maintenance rule, you can do a qualitative analysis of the risk, qualitative risk assessment and decide if the way that you're doing the maintenance things may need to be postponed, rescheduled, done a different way, contingency plans or compensatory measures may need to be taken, and in fact, with all kinds of things that have to be analyzed qualitatively in terms of risk, the risk assessment amounts to a recognition that the risk is increased and then taking some kinds of actions that can reduce overall plant risk or that target specific areas that need to be looked at because of the nature of the external conditions that are causing the increased risk.

So it can be done qualitatively in a blended fashion.

MR. CAMERON: Okay. Thank you.

And, Mike, again in keeping with perhaps necessary clarifications in the letter. Okay. Good.

I think that we probably should take a break now and see if we can get back on schedule. I'm putting Mr. Thorson's issue, which is RTCA capability, does that transfer into inoperability or increased risk; I'll put that in the parking lot, and we will come back and discuss that.

And I think right now we're slated for about 15 minutes on the break. We do have more hard copies of the slides coming. There is a USB one of those little gadgets for those of you who want to plug it into your laptop and download it, but we will have hard copies for you.

Restrooms are back in that corner. There's coffee on the lobby level. I have about 17 to 11. Why don't we come back in about 17 minutes and we'll get started.

(Whereupon, the foregoing matter went off the record at 10:42 a.m. and went back on the record at 11:00 a.m.)

MR. CAMERON: Okay. Just a couple of announcements before we get started with what we're calling the risk insights panel which are going to cover material related to GL Questions 5, 7 and 8. One is Mr. Thorson raised the issue of RCTA capability and whether that corresponds to inoperability or increased risk, and excuse my ignorance in characterizing that, but I think you all know what the issue is.

We're going to -- it seems like that fits into the discussion of not this panel but the next panel. So we're going to try to get to it there, and we're going to go to Mr. Tom Koshy of the NRC staff to sort of address that for us, and then we'll get into a discussion.

Another overarching issue that we need to get to at some point that I've heard people express a concern about is the whole idea of providing information to the NRC, the licensee providing information that really is in the province of another organization over whom the licensee has no control over.

So that seems to be something that runs through these discussions.

We're going to go to the next panel and we have Dale Rasmuson from the NRC staff Office of Nuclear Regulatory Research; Mr. Bill Raughley from, again, NRC Office of Nuclear Regulatory Research; and then we have Mr. Gary Vine from EPRI, the Electric Power Research Institute.

So are we going to start with Dale or

Bill? Dale, then Bill, then Gary, then we'll give them an opportunity to ask each other a question or so, and then we're going to just go to you.

There's supposed to be a lunch break in the middle of this panel, and we'll just see how the time is going.

So okay. Let's turn it over to Dale.

MR. RASMUSON: Thank you very much.

I'm Dale Rasmuson from the Office of Nuclear Regulatory Research, and as you know, NRC recently finished a detailed update of station blackout risk in terms of core damage frequency. The report has been published as NUREG CR 6890, and it's currently in printing and will be issued soon.

Next slide or this slide. That's the one I want.

Okay. Station blackout risk measured in core damage frequency is highly dependent on four factors. They are loss of off-site power frequency, loop duration, emergency diesel generator reliability, and plant specific coping features such as battery depletion time, turbine driven pump performance, alternate on-site AC power sources, and reactor coolant pump seal design.

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 operational status.

For critical operation, plant centered and switchyard centered frequencies have decreased, but the grid related frequency has increased. The weather related frequency remains about the same, and may I say that for the -- there was only one shutdown or one plant centered event for the latter period, 1997 through 2004.

For shutdown operation the switchyard frequency has decreased and grid related frequency has increased, but is not dominant compared with the results for critical operation. Notice the difference in the Y scales between the two graphs. The overall shutdown frequency is approximately five times the overall frequency for shutdown operation.

Next slide, please.

In this slide we compare seasonal variation in loop frequency. The summer period is defined as May through September, with the non-summer period being the other seven months. For critical operation, all four category frequencies are higher during the summer period. In particular, the switchyard centered and grid related frequencies are much higher during the summer period.

For shutdown operation, the frequencies

for most categories are about the same. However, the grid related frequency is greater during the summer, but again, it's not dominant compared with critical operation.

Next slide, please.

This slide shows a comparison of critical looped events by months within the two time periods. In the first graph we notice that the events occur about equally across the months, 1986 through 1996. And the dark ones, the blue ones are the summer period. The lighter ones are the non-summer.

The second graph shows that the vast majority of the events occurred during the summer period during 1997 through 2004. The different summer versus winter is highly statistically significant, even with the August 14 2003 events removed and if we, in addition, remove the Palo Verde events, the three vents that occurred in '04.

Next slide, please.

This slide shows the number of switchyard centered and grid related events for critical operation and shutdown operation for the summer and non-summer periods. The number of critical operations switchyard centered events has decreased, but the 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.

Average durations have been increasing, in part, because of the number of shorter duration events has been decreasing, while the number of longer duration events has remained about constant.

Next slide.

This slide shows the results of the station blackout evaluation together with two results from sensitivity studies. The industry mean, median, and the max and minimum -- these are point estimates -- are being shown, and that shows the range for all the plants. So that represents 103 values in those ranges there.

The industry annual mean SBO risk is in the mid ten to the minus six range based on updated loop frequencies, including '97 to '04 and updated component data from mainly '98 to '02. Know that if only the '03 and '04 data are used to determine the loop frequency, the SBO risk would increase by approximately a factor of three over the baseline case. This is not shown in the figure.

The two sensitivity study show an increased loop frequency during summer and decreased loop frequency during the non-summer, and you can see that there is an increase in the loop frequency for the summer event, which is based on an increase in the frequency of the loss of off-site power frequency.

I will now turn the time over to Bill.

MR. RAUGHLEY: FERC Order 888 was issued in April 1996 and require that generators have open access to the electric power transmission system. Open access transmission generally results in more power transactions and consequently more power train transfers that change the power flows.

Increased power flows on the transmission system have the potential to lower the nuclear power plant off-site voltage to a level of impact.

Regardless of the restructuring status or participation in the power market, all states and all MPPs are exposed to the design and operating changes associated with revised power flows attributable to open access transmission. The case in point is the 1999 Callaway event. In this event the reactor tripped from a problem in the heater drain system. At the same time heavy power flows from interregional transactions in the power market depressed switchyard and safety bus voltages below that required for 12 hours.

This event prompted an IN and subsequent RES interest in NERC transmission operating data that I'll discuss later.

The next bullet, the U.S.-Canadian August 14th blackout task force report states that with the absence of major transmission projects in the past ten to 15 years, utilities have increased the utilization of existing transmission facilities to meet increasing demand without adding major equipment.

The task force report goes on to state that the systems being operated closer to the edge of reliability than it was a few years ago, and if nothing else changed, we'll see more widespread events.

In 2004, we had the West Wing event that involved the simultaneous trip of three Palo Verde units along with three loops.

As I've mentioned already, experience has shown grid initiator reactor trips and loops impact nuclear plant operation, and I've listed a few examples here.

They also discussed the loops. Similar to the loops, many of the recent reactor trips initiated in the nuclear plant switchyard, the transmission network or were widespread grid event.

At the March 2005 regulatory information conference, Mr. Dyer who first spoke stated that in 2003 there were 23 reactor scrams of nuclear power plants associated with grid problems, eight of which were the blackout, and in 2004 there were 15 scrams associated with group problems.

And as the last point, during the blackout everything went as planned. There were no safety problems, and the plants performed as expected, but there were some event anomalies, I think, that highlight some of the concerns that were expressed.

During this blackout, one of the licensees was testing his EDG to the grid for its monthly surveillance. The operator tripped the EDG and it realigned to the safety bus, but it shows one of the concerns about the risks for maintenance activities with reactor power. In this case you'd lose both the loop and the diesel from a single initiator, and in this case if you carry that thought forward through the single failure criteria, if another diesel, then you'd be in a station blackout, and that's one way to get to a station blackout.

Had the transmission operator understood the importance of a diesel or the nuclear power plant, the operator, the condition of the grid that day, this activity may have been delayed or stopped to avoid the risk of exposure.

Next slide.

What I've shown, this slide relates directly to Paul's point about the last paragraph in GD-17 where the licensees need to take provisions with regard to the probability of a reactor trip given a loop.

And this slide shows increases and seasonal variations in that probability, and it is sometimes referred to as a consequential loop. On the left are the results of a study that was finished before the August the 14th blackout, and on the left are the results of the L study. On both studies you can see that the annual frequency is doubled, and then the summer frequency is approximately doubled against.

In these events, the reactor trips for whatever reason, typically resulting in a loss of generation in addition to a relatively large load from the transfer of the NPP house loads, nuclear power plant, house loads from auxiliary power to off-site power. About 90 percent of the plants are designed such that this happens.

This results in a voltage depression that lasts a few seconds until the grid makes up the difference. During an accident there would be an additional load and voltage drop from the starting of a safety load.

In either case if the voltage dropped low enough, they operate at the greater voltage relays, which operate or which automatically start the EDGs.

Reactor trips of random tests of the capacity and capability of the grid in the events that are driving the numbers here, the capability of transmission system to supply power was affected by transmission and non-safety nuclear power plant equipment. In one case the plant owned transmission load tap changer had been inoperable for 11 months, and the plan grid operator response following the reactor trip was ineffective.

In another case, the transmission system owned both its regulator, had been wired incorrectly, and the licensee reported that heavy power demand and transmission outages contributed to the voltage suppression.

In another case, a switchyard circuit breaker, the generator circuit breaker, which is in the switchyard, faulted, failed to open, and it resulted in a second fault that caused the loss of off-site power.

The grid is being operated in a condition for whatever reason such that a reactor trip will result in the loop than the probability of a loop for that period of time is significantly above the numbers on this slide and in Dale's presentation.

The entity that knows whether or not the reactor trip or unit trip or reactor trip will result in a loop relies on input from the transmission entity.

What I also showed in the NUREG 1784 is I pointed out that the typical risk analysis is to consider a reactor trip in the loop to be independent events. That is, the probability of a loop initiating event is not impacted by the trip. As shown in this NUREG, parsing out the consequential loops from the typical loop fault tree in the assessment of risk for maintenance and tests provides for a way to do sensitivity analysis to evaluate the impact of combinations of degraded grid EDG unavailability, summertime probabilities and the remaining loop frequencies.

As shown in this NUREG, these risks may be made partially or fully offset the risk reduction from SBO implementation.

Next slide.

And that might help to answer some of Parviz's questions that he asked at the end of the last presentation.

What we did here is after the August blackout, we were tasked to obtain and analyze grid data to assess the grid reliability so as to identify changes, emerging trends that may be precursors to impacts on NPP operation and risk. The nexus between the grid and the NPP, or I keep calling NPP nuclear power plant, is that the nuclear power plant is connected to the grid as the generators of load and subject to the same condition.

What I'm going to show in the next few slides is an assessment of grid reliability based on performance trends developed from their NERC definitions of grid reliability. These are the only definitions of grid reliability I could find, and this includes the 600 grid disturbance events from their database. It's the disturbance analysis database, which is on their Website, and approximately 8,000 transmission load relief requests from '97 through 2005.

We used the data to provide reliability measures to gauge the recent changes in grid operation. The work benefitted from the guidance and peer review by several NERC members.

What I did basically was bend the NERC 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 year-to-year days vary cyclic just like the loop data. I had 20 years of the data and divide it into five-year intervals on the horizontal axis and the number of events on the vertical axis.

For the operating reliability, I came up with the number of weather events in yellow and the non-weather events in red. The NERC data clearly indicates decreases in grid reliability.

As another observation, there's enough change that the data since 1997 may be more representative of grid operation than before.

On the left, improvements in adequacy of the generation supply over the 15 years prior to 1999 have been offset by the declining group performance from '99 through 2003. On the right, the operating the liability was less from '99 to 2003 than it was for the preceding 15 years for both weather and non-weather events.

Next slide, please.

This slides is a subsort of the operating reliability data. On the left are the larger events, those involving a load loss of more than 800 megawatts and the outage was around 750, 760 megawatts, and I rounded it up to 800.

On the right are the events where it took more than four hours to recover power to most customers.

The figures show that since 1999, the bigger blackouts are getting bigger, and of longer duration the blackouts that occurred before '99.

I've got tons of sorts of this information and some of them that the parallel Dale's data are that since '99 the median size and median duration of blackouts have increased.

Thus it appears that pushing the transmission harder has diminished the grid's capability to withstand contingencies when not operated within reliability limits. It appears that the U.S.-Canadian blackout task force assessment was correct.

We would expect the implementation of enforcement of reliability standards would improve the situation and only time will tell. It's going to take four or five years at least to change the reliability trends that we're looking at on either the nuclear plant side or the grid side.

Next slide.

This is the sort of NERC disturbance data by months similar to Dale's sort by month. In this slide I measured, and it's from 1997 and 1993.

Clearly, there's seasonal variation in the NERC disturbances which increased sharply and peak in the May-December time frame.

As you can see, you must be prepared for a loop all the year, but what we're trying to communicate here is that the things are changed enough in the summer that you need to use different numbers for your summertime risk assessment.

Next slide, please.

This slide was taken from the NERC long-term reliability assessment. You heard earlier Mr. Dyer or Mr. Sheron say that there was some indication that in some areas there's a depression of or lack of a reserve.

This slide deals with the capacity margin, which is what's left over after you take the connected load less planned/unplanned outages, less your reserve requirement so that this is what's left over.

Now, what NERC is that they do a ten-year forward looking assessment and the executive summary of the current assessment which looks out to 2014 states resource adequacy is dependent on new generation projects and the transmission system will be operated at or near limits more frequently and that the fuel supply in most regions are adequate.

These assessments examine, among other things, the seasonable variation in the load and capacity margins. Other information in the NERC assessment shows the load growth of approximately two to three percent per year and a decline in new generation projects.

This will lead to the decrease in capacity margins which are projected in the NERC slide here. In this figure NERC compared a series of four ten-year capacity margins for the summer operation of U.S., and on the top you're starting with 2002, and as time goes on, as you proceed from top to bottom, it's 2002, 2003, 2004, 2005.

So for 2005 in comparison to 2004 -- I'm sorry -- the capacity margin for 2006 is about 15 percent less than the last projection, and decreases to nine percent.

The curve shows the capacity margins are shrinking with time. With less margin the grid will be less robust and have less give to it.

The NERC regions have input to these assessments and typically evaluate the information, and if you pull that thread, if you go from the NERC assessments to the ISO assessments, that that's where you can get into where some of the ISOs are showing an erosion of reserve requirements in the 2008-9 time frame.

And likewise these NERC assessments, I think, are very insightful. If you keep pulling these threads, things seem to go the way they say.

As a result of the Callaway event, RES took interest in the NERC transmission load relief request logs and trends that are available on the Website. Anticipating transmission line congestion for more power transactions in the power market, they're created the system of procedures and logs to manage the congestion in eastern interconnection.

The reliability coordinators in the transmission operation monitors the transmission line limits. As predetermined limits are approached. The reliability coordinator issues a TLR Level 1 to Level 5. Level 1 is an alert. Two to five require actions such as backing out of a transaction or reconfiguring some portion of the system.

The TLRs come from approaching the limits as a result of power transactions. We've used the info here to once again show the seasonal variations. In addition, the chart shows the TLR data has become more -- the system has become increasingly congested from '99 to 2005. So if you start, the bottom line is

'97, '98, '99, and you work your way up to 2005. So as deregulations kicked in and the power transactions have increased, just a lot more activity.

And then I've done other sorts of this data to show that there's a concentration of problems at some flow gates and at some times in here. So that I've indicated some bottlenecks or problem areas.

Next slide.

In this slide what I did was a log-log plot of both the NERC data on the top and the NRC Dale's loop data on the bottom. The durations, the actual recovery times for the nuclear plant data, and the restoration times reported in the NERC data, and the blackout data, the nuclear plant blackout data is up in the -- near the curve and goes down to the -- much before the 1,000 minute drop-off.

The NERC data, they have eight or nine points reported from the different regions, but that falls up in the knee of the curve also, but the point here is that the August 14th blackout event is not an outlier on either curve.

Note also on the curve if you look at the grid events are longer than the nuclear plant events, but it goes to show that the nuclear plants could be exposed to events longer than those that they're experiencing.

The events on the bottom of the NERC chart are largely from ice storms where several transmission towers were toppled at the same time. The risk here comes from the fact that as the event gets longer, the diesel reliability drops off. So if you plug in some of the longer event numbers, you get much lower diesel reliabilities than you would from typical nuclear plant event.

The other thing that's happened here is that most of the recent events are at or below the knee of the curve and the events before 1996 are up above, and most of them before 1996 were plant centered. So what has happened is the plants have corrected their problems. There has been a disappearance of plant centered events as shown on Dale's slide, and what that has left is a lot of switchyard transmission system and grid events, so to speak, and the recovery times of those are longer. So that I think that explains the increase in the loop duration.

But nonetheless, the numbers are the numbers, and that's what you've got to use in the analysis.

On the last two slides here, I've

summarized what Dale and I have told you, and our bottom line is that we think the overall data and experience support the generic letter. There's a lot of offsetting variables going on here, and looking at them all at the same time, the overall loop frequency of the looped events have been declining since '88, '86, but there was an upturn in 2003-2004. The grid center loops are up significantly in recent years. The average loop duration has increased significantly since '86.

In recent years, almost all of the loop events have occurred in the summer, May to September, and that's where NRR is getting their seasonal variation conclusion from.

And then the last slide, recent events have raised questions about the likelihood of a loop caused by reactor scrams. The seasonal variations in loop fence and grid reliability raises questions about maintenance of EDGs or SBO coping features during summer months or during times of grid distress.

The fact that there's change going on adds uncertainty about the future. You've got a moving target here we're trying to hit, and the point of all this loop stuff that I went over from NERC is that 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 analysis of the data, but those differences have been largely reconciled over the years.

What was happening in the early years is that both industry and NRC were relying heavily on LER information for assessing the frequency and duration of either diesel events or grid events, and it turns out that a lot of that data was not very useful.

We ended up having to go talk to individual plants and find out exactly what happened in each of these events, and we determined in many cases, for example, that maybe the grid had been declared inoperable for a period of two days when it was available within an hour or two, but it was not -- the plant was not put back on the grid until we were really confident that it was a stable situation, nd we would continue to operate off the diesels, and of course, that would skew the data tremendously toward a longer even than was really deserved in the data analysis.

There were similar cases where there were back-up or alternate AC power supplies available off site or on site that weren't reflected in the LER. We would learn about those things as we investigated the event in more detail.

As we began looking at the data much more comprehensively, NRC joined us and then through the '90s and into this decade we usually found that the raw data differences between our analysis of these events and the NRC's event, pretty minimal. We've been pretty close on the raw data since those early years.

We've published a number of reports. We continued in this analysis of both grid and diesel reliability since the station blackout rule and continue to do so. We've had very good cooperation with NRC Research, which we have an MOU with and we've done a lot of work together in this and other areas.

But there has been some divergence in our analysis of the event since the August 14th event, and perhaps a little bit earlier than that as well as we began looking at grid centered events a little differently.

Again, not a huge divergence in the raw data, but significant divergence in interpretation of the data. It's important to recognize just for perspective that the goals of the station blackout rule have been met or exceeded, and I'll say a little bit more about that later, and also that the industry, I think, even though the grid situation that we all face due to deregulation and technology changes and everything else is moving. We've generally kept the pace of that with our own programs at our plants with configuration risk management and our maintenance rule programs.

Next slide, please.

Again, for perspective, no nuclear plant either caused or contributed to the August 14th event, and all of the affected plants performed as designed. You need to remember those, those important factors.

Arguments about the dominance of the summer events I think needs a little closer examination. First of all, you know, if you look at this statistically, some of this is absolute data, and some of it is relative data, and if you look at it on a relative basis, you get a pretty skewed picture, and I think some of that came out in the last two slides that NRC presented.

First of all, a lot of our data is skewed by one event, the August 14th event, which, again, all of our plants did perform as designed in the August 14th event.

The root cause of all these loop events is generally not correlated to season. Now, this is an important point. If, in fact, the summer is driving a large increase in loop events, one would assume that if you go down and look at the root cause of these summer events that you'd see a seasonal basis or a seasonal driver for that higher frequency, and in fact, that's not the case. I'll get to some more details on that later.

Emergence of longer duration grid events as a higher percentage of the total loop events is really driven by the fact that we have reduced the number of the shorter duration or the plant centered events over the last 20 years. It's pretty parallel, I think, to the performance we've seen in or the outcomes we've seen from PRAs in general that have shown that you've reduced plant risk by roughly an order of magnitude over this period primarily by dealing with plant centered risks and improving our plant performance, design operations, and so forth, to reduce our PRA numbers or core damage frequency numbers, and that what that leaves you, of course, is a higher percentage of external event contribution to risk.

The same thing is happening here with the grid. As we continue to improve our plant capabilities, the residual that is left is going to be more externally driven.

The total number of loop events over

history has actually gone down over this 20-year period. So I guess the point there at the end is that no good deed goes unpunished as we continue to improve our plant safety. The focus gets on that residual risk, and that's where we're focused today.

Grid weaknesses can occur at any time. It's not strictly a summer related phenomenon. You have to be on guard 12 months out of the year. Just some simple points here. The longest recent occurrence of a sustained grid weakness that lasted for 776 hours -- that's quite a period of time -- occurred in California in January and February. This is when they were less than 1.5 percent reserve margin for an extended period of time.

The major northeast blackout that occurred that kind of drove the creation of EPRI occurred in November. Picked up last week's Nucleonics Week. Weather conditions forced four parallel units off the French grid. This event occurred at the end of December, 6,000 megawatts down.

So there are events throughout the year, and I'm going to say a little bit more about the summer connection here at the bottom of this slide and later, but we need to recognize that this is not just a simple, you know, worry about this in the summer and not 12 months out of the year.

Grid weaknesses can occur any time. If you look at some of the charts that we're shown by NRC having to do with reserve margin, reserve margin is a relative term, and if you've got a lot of plants out and spring outages and fall outages, whether it's nuclear plants or fossil plants, and your reserve margin can come down quite a bit if you've got unexpected warm weather in the spring or something like that.

The next bullet is an example of that when they had a pretty serious problem in California just April of this last year, because it warmed up quite a bit before all the plants were back on line from their spring outages.

The primary causes of loop events over the last ten years and in order of importance are shown here at the bottom of this slide. Random equipment failures, adverse weather conditions, the August 14th event which was the third largest contributor which was really mostly maintenance related, driven out of the grid, and then random human errors. These are the first four. There are others. Animals created quite a few of them as well. That's number five and number six.

But the important point is that of these four primary causes or root causes, none of them are really specifically restricted to a summer type of a problem. Random equipment failures can occur 12 months out of the year, as can adverse weather conditions. We have adverse weather conditions in the winter as well as in the summer.

So we just need to keep this perspective on this summer data.

The draft generic letter talks about the summer months being May through October. That's a five-month span, and there's also concern about hurricanes. I think Brian mentioned that this morning. Those, as we know from this last year's bitter experience in the South, extended into November and I think even early December.

So we're kind of categorizing a six-month period, five to six-month period here as a period of concern, and if we end up taking, you know, an extreme position here that basically says no maintenance on plant electrical equipment during an extended period of time like that, we could have some unintended consequences.

So I think from a more sophisticated risk approach we would prefer to see a look at this. It's not just as simplistic as watch out for the summer and not any other time.

The top bullet here just repeats the point I made earlier about the conclusions of NUREGs analysis of the station blackout rule. It was effective in meeting NRC's expectations and, in particular, diesel reliability has been higher, higher than was originally anticipated when the rule was crafted, and this has kept our overall station blackout effectiveness quite high over the years.

The likelihood of grid induced loop is a function of plant location. Again, not a one size fits all solution here. We worry sometimes about plants at ends of transmission lines. There are a number of plants in situations like this, the Florida peninsula and so forth. They have a different situation than the rest of the country.

Weather vulnerable regions. Again, this is not just summer phenomenon. There are different weather concerns at different parts of the countries at different times.

Industry's capability against loop events has improved greatly since the days of the station blackout rule implementation. It's not that we've simply complied with the coping times and the station blackout rule and haven't done anything since then. We've done a huge amount of work. You're going to hear a lot more from what INPO has done in this area. We've created a lot of tools that have been very helpful in helping plants, and of course, the advent and continued improvement in plant specific risk models has helped a great deal in dealing with grid reliability.

Next slide.

We have a forum, an EPRI committee, in effect, that is called the configuration risk management forum. It's actually meeting concurrently as we speak here. Their annual forum is occurring this week down in Florida.

This forum is the focal point for industry's assessment of CRM practices across the fleet. CRM, of course, is essentially a real time capability to analyze plant risk and to be able to make operational decisions by operations people, maintenance people and so forth, to optimize the timing of those factors that you have control over, such as placing equipment out of service for maintenance.

The workshop at the same place as we speak is explicitly including discussion of grid related events in the agenda, and there are NRC personnel in attendance.

CRM is focused on managing risk due to both unplanned and planned conditions as primarily those are controlled by operators, and it explicitly includes consideration of grid issues. Based on a lengthy survey that we did within the CRMF in 2004, a little over a year ago, we've determined that grid reliability is being addressed in the majority of plant models. You'll see at the bottom of this 85 percent of the plants responded, and of those 85 percent, the vast majority of them are either quantitatively or qualitatively addressing grid performance in the way they do their CRM modeling, and obviously their management decisions on making outage decisions and maintenance rule decisions.

Next slide, please.

The survey that was conducted in 2004 examined three specific type of grid disturbances: severe weather, switchyard maintenance activities, and other external events that could affect the grid, including grid instabilities, regional flooding, forest fires, and other things that are in effect.

And conditions affecting risk may or may not be under the control of plant staff. Obviously plant staff has control over switchyard maintenance, but it doesn't have control over maintenance that's being done, you know, 100 miles away from the plant.

It doesn't have control over weather obviously, but at least it can anticipate weather conditions.

We've talked a lot about quantitative and qualitative means being used to assess grid performance and grid reliability. This is kind of a repeat of a point that the gentleman from San Onofre made before the break, and that is that we can do a reasonably good quantitative job of assessing switchyard reliability, and we can quantitatively, although not with the same degree of accuracy, but at least quantitatively make some reasonable assumptions about weather related events, if there's a storm coming or stuff, you know that you've got a heightened condition of risk.

The area that EPRI has, as far as we can tell from all the CRM activities in the industry, have not been able to quantitatively model is the grid itself. We've been working on this for a number of years. We've got a pretty significant cross-sector effort at EPRI with our nuclear sector, our fossil sector, and our power delivery sector working on these grid reliability issues, and although we've done a lot of pretty sophisticated modeling of the grid, the ability to feed back a reliability number back to the plant on what the condition of that grid is at any point in time is a pretty impossible task at the present time.

CRM obviously requires increased maintenance controls when conditions indicate, but it's determining when those conditions really indicate that that is the tough thing to do. I mentioned that we've got a pretty significant cross-sector activity at EPRI looking at grid related risk and performance. We're involved in establishing industry-wide guidance across the board in both plant and grid areas. You can see the list of the things that we've got covered there.

We also addressing a lot of equipment reliability issues through either configuration risk management or pretty extensive switchyard users group, transformer users group that's looking at those aspects of plant performance working hard on such things as switchyard breakers, transformer liability and so forth, with guidance on both maintenance and operations of those components for improved reliability.

We're looking at turbine generator torsional problems that have cropped up as a result of grid oscillations. We're going a lot of work with devices for voltage support for maintaining VARs.

The next slide, as I mentioned, we've issued about 50 reports over the last 20 years on reliability. These are the last four that have been issued related to off-site power reliability and causes of losses of off-site power. We do a cumulative update about every year or so.

And finally, as I said, the ongoing CRM workshop in Florida has taken away the top EPRI experts on grid performance and grid reliability. So I'm filling in and probably will not be able to answer as many questions as these guys would. Frank Rahn is the overall coordinator of our grid reliability work and works with people in power delivery and generation.

His boss, John Gaertner, and Ken Canavan are deeply involved in the PRA side of this. Wayne Johnson is our equipment reliability expert for grid related matters.

And that's it.

MR. CAMERON: Okay. Thank you very much, Gary, Bill, Dale.

We do have the hard copies of the slides available out in the back. So all of those helpful E-mail addresses and hone numbers will be on there.

You just heard a presentation on the data and on the implications of the data, and I guess the focus of this discussion should be on what the implications of the data are, and I think it would be helpful for Mike Mayfield and all of his staff if you had suggestions on how the GL should be adjusted based on what your view is about the data, please bring that forward.

I'm going to give the panelists an opportunity if they want to ask a question or comment on what the other panel has said before we go out to all of you.

Gary, anything at all? Bill?

MR. RAUGHLEY: I had a couple clarifications. One is I don't think the NRC ever said no maintenance. What we're trying to do is get the proper numbers used in the assessments of risk when you do maintenance tests outage activities.

Ma'am, if you could go back to my next to the last slide. That one -- next one. One more. There you go.

With regard to this plant, you know, the fact that I said that the plants had eliminated the plant centered events, if you look on these curves, it provides a way to visualize the problems, is you have a relatively flat, large number of events which are of low consequence. They're actually much, much less than 100 minutes, and those are the ones that are largely plant centered, and those have been eliminated.

The risk significant events are on the straight part of the curve, and those are the ones that remain. So what they've done is you have eliminated the low risk events from a risk perspective. It's not to say that the plants haven't done an outstanding job in eliminating the actions to prevent recurrence of the problems, but from a risk perspective, you haven't done anything.

MR. CAMERON: Okay. Dale, anything?

MR. RASMUSON: Yes, just one clarification. In the comments that we received from EPRI and from others on our reports in that regarding the August 14th event, a lot of the comments focused that we ought to count it as one event, but I'd just like to point out that that is changing the definition of loss of off-site power. We're not saying that the definition that we've used that you saw here was that it affected the plant, and we're calculating risk of the plant.

There was one event in August 14th, but it's not a loss of off-site power event, you know. I mean according to our definition. According to our definition, there were eight occurrences of loss of off-site power where plants lost -- their safety buses went dead and the EDG started, and so that's what we are counting, and with the fact that if you look at the distributions, that's when the events occurred, changing the subject here.

The events occurred during the summer. I mean, no one can argue with that, you know. We're not saying what the causes are. We're not looking at that. We're just saying they occurred during the summer. Those are the facts.

And so we can go and say some other things, but that's when the events occurred. And people bring up like other blackout events, but you know, like the '96 grid blackout in the West. No nuclear power plants lost power to those things, and so you know, they're not relevant to our PRA analyses. So that's just some clarification I'd like to point.

MR. CAMERON: Okay. Thank you, Dale.

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 bring the two parties together so that we get a common understanding and treatment going forward?

Because I see the different opinions just compounding over time and the gap getting broader instead of coming together to a common approach. So I would just like to offer as a potential follow-up action item for us to get together and get into some down-to earth dialogue so that we don't have these inconsistencies in interpretation and assessment.

MR. CAMERON: Okay. Thank you.

And obviously that's not only just a short-term related to the GL, but a longer term. John, do you want to talk to that?

Go ahead and please introduce yourself.

MR. KUECK: This is John Kueck at the Advisory Committee for Reactor Safeguards, although I am not here representing the Advisory Committee but myself.

As Gary said, this work has been going on for 20 years, and I guess maybe him and I are the oldest folks in the business since I started that work back in the '80s myself.

MR. CAMERON: We'll let the record show that.

MR. KUECK: Yes. Looks can be deceiving.

Yeah, that's a great comment that I think Alex has made, and you probably need a third party in this, and that's NERC. I think it would be important to get NERC's views on this. I know when Bill released his report there were comments raised by both NERC and NEI, and they're very contrasting.

When you look at one set of comments from the people that do this for a living, you get a different perspective than NEI. So I think it's very important that all of these statistics has a fundamental engineering basis as to why they represent what they represent, and unless you have that basis, statistics are just numbers.

So I think it's important; it's extremely important to probe down and find out the basis and then agree on that basis. I mean, I think no one more important to get involved in that process would be NERC.

And I guess from having done this work for all these years, I mean, we're only kidding ourselves if we believe nothing has changed in the last 20 years. A lot has changed in the last 20 years, and things are going to continue to change, as you can see with the plots that Bill had put up earlier about the reductions in spending reserves and so on.

So I think it's not only today that we're needing to deal with this problem. We also have to think what's going to happen over the next ten years. When they came in for advanced reactors and they talked to the Commission, the driving need for new reactors is based load capacity by 2015.

Okay. What's going to take us to 2015? I think we have to look also into the future in this and say are we doing the right thing. Are we getting prepared to carry this load into the next generation of nuclear power plants?

Because if we don't do it now, there is not going to be a new next generation. We have to be able to address the most important risk contributor to nuclear power plants today, and that is station blackout. Anybody that does risk knows that that's driving things. So just a few comments from my perspective.

MR. CAMERON: Okay. Thank you, John.

And I'm going to ask the panel if they have any comments, but two issues on the table. One is a longer term action, not just int he NRC's lap, but in EPRI's, NERC, but is there a mechanism that can be used to try to reach consensus on the implications of the data?

So I know that Mike Mayfield has that on his action list. Short term, again, Alex characterized it. There's a difference of opinion here on what the implications are for the GL. I guess that the NRC staff would be interested in any comments on how the GL might be changed to accommodate these different opinions.

So I'll leave you with that for a second, and then I'll go to Dale and Bill and Gary to see if they have any comments at all on what we heard from Alex and John Kueck.

Dale.

MR. RASMUSON: I just wanted to say that, you know, we have met with EPRI, you know, to coordinate some of these things, and we do differ on the August 14th event. There is a difference on that, but the definition that we have been using is the definition that has been around since 1032. You know, that was the definition that was used there for loss of off-site power.

And so we're not changing definitions at all in that regard. I'd just like to emphasize that.

MR. CAMERON: Bill, anything you want to say in regard to the dilemma that Alex has and the suggestion that he made?

MR. RAUGHLEY: As Dale said, we've met, I think, three times with EPRI. Dale is the last word on the statistics. We do have the same raw data. Dale did base his risk. Baseline risk is based on the minimum recovery time. He's done sensitivity analysis for the actual times, and with regard to the numbers of events, one other major point of disagreement is EPRI definitions include events when the reactor is not at power, which have absolutely nothing to do with station blackouts. So they don't enter into Dale's statistics, and that's the fundamental difference in the numbers, is that they exclude -- you reduce the summertime event from eight to one, and then you add eight non-power events that are largely in the winter, and then that masks the summertime phenomena.

So I think we understand the difference, and I don't know how long we want to beat this horse to death, but Dale is using numbers that have been around since 1970-whatever, you know, when John was a youngster with hair, and he hasn't changed a thing. It's just pumping the same data into the same formulas and getting the answer, and it shows change, and I think we need to respond to it.

And, yes, we would love to meet with the industry and keep this discussion going for the long term, but I think for the short term, the numbers are the numbers. You know, unless we want to change the definitions, and again, that's a long term thing.

MR. CAMERON: Okay. Let's ask Gary to comment on this.

MR. VINE: Sure. I appreciate Alex's comment. I think to one of the points made here about including shutdown events or not, we think that shutdown events, even though the plant is down at the time, is relevant operating experience to learn from, and so it does tell you if the plant was up what would have happened, and so we look at it more broadly, and I think that helps balance the picture.

But I think the most important point to make here is that the differences of view between the industry and the NRC this time around as compared to 20 years ago when the station blackout rule is originally being formulated are fundamentally different.

In the early run through this in the '80s, it really was the raw data that we disagreed about, and we worked through a process to get to a joint understanding of that raw data, and then things went pretty smoothly, and in fact, our MOU with the Office 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.

MR. CAMERON: Okay. Let's hear from Rich Barrett. Rich.

MR. BARRETT: Thank you, Chip.

I'm Rich Barrett. I'm with the Office of Research at the NRC.

And I can certainly appreciate Alex's question. You know, we have a number of regulators and regulated entities here today, and they've got to make decisions about where to go next in putting out this generic letter and in responding to this generic letter, and it can be confusing when you're hearing different perspective from the research entity of the NRC and the principal risk entity of the industry.

And I can say certainly from the perspective of the NRC that we are committed to continue this work and to cooperate with EPRI and others to get to the very best possible insights from what the data are telling us so far and what the data in the future will be telling us as we see more experience and we pile up more years of experience in this area, and as the grid continues to evolve and the performance of the grid continues to evolve.

What I thought was interesting this morning in the three presentations was not just the information about the numbers of frequencies of losses of off-site power, the durations of losses of off-site power, but I think it's important as both Bill and Gary did to go beneath the data and ask yourself what's going on here. What's going on in the grid?

For Gary, from Gary's perspective, he took a closer look at some of the root causes, and I think it's important to look at the root causes, and some of these root causes that you saw are not seasonally related. We know that there are others that are seasonally related.

I think you also saw that there were some important insights here related to other trends, plants that are near I believe he called it the edge of the grid, plants that are in extreme weather situations. These are all questions that need to be considered in response to this generic letter.

Conversely, Bill presented some information that we've gotten, we, the NRC, have gotten from NERC related to precursors to loss of off-site power, and I think it's very important to take a look at these deeper -- a deeper look at some of the things that relate to the vulnerabilities of the grid or the reliability of the grid both from the trends from year to year and the trends from season to season.

One of the things I saw this morning that I hadn't seen before was what appears to be an upturn, more and more of an upturn during the December time frame than there was in previous data, and I think that's a long-term challenge for all of us.

But at the moment, I think there is no question that we have to address the questions that have been raised. Gary said that a lot has changed and a lot has improved in the electrical systems since the station blackout rule was put in place, and he gave some examples, which I'm not in a position to evaluate, but I think it's also clear that there is a difference in the grid. I think it's also very clear that there are some differences in the way in which the plants are being operated, the technical specifications have been changed significantly with regard to allowed outage times, and it's difficult for us at the NRC to evaluate how all of that plays out in terms of the risk to the plant and continued compliance with the regulations.

And so that's the reason why what to some extent has been a research question because it's now moving more and more over the past two or three years into the regulatory arena and the issuance of this generic letter.

So I guess my bottom line would be, yes, absolutely, Alex, we need to go forward, the Office of Research and NRR and EPRI, to continue to try to maybe get back to what Gary said was the case a few years back where we understand each other's analyses and we can come to agreement, and in the meantime we need to continue to gather more information about the health of the grid. We also need to take a very close look at the responses to this generic letter to make sure that we understand how the plants are being operated.

MR. CAMERON: Great. Thank you. Thank you, Rich. A very positive.

I guess I would just put the question, again, in a different way. Is there anything in the generic letter now based on the NRC's interpretation of the data that would produce unintended consequences? Is there anything that should be adjusted or changed in the generic letter?

And I guess that's a good segue for Mr. Thorson.

MR. THORSON: James Thorson, Detroit Edison.

I guess having listened to this recent set of presentations, the Question 5 "Charlie" on the draft generic letter, is there a seasonal variation in the stress on the grid in the vicinity of your nuclear power plant site? Is there a seasonal variation in the loop frequency? And then if yes, discuss when they do occur and what's the magnitude of the variations.

I guess, you know, one of the objectives for this form was for the industry to kind of understand what the NRC's expectations was and how we would provide information to you with respect to this, and I guess I'm a little reluctant to get quantitative in my response to the NRC to this question based upon the general, I guess, lack of agreement or on how to interpret the data.

And then secondly, in particular, the seasonal variation and the loop frequency for our plant. I'm hoping that our frequency is such that I can't detect a variation. So I guess what I'd like to ask specifically: is it acceptable to remain qualitative when we answer this question or are you requiring a quantitative assessment?

MR. CAMERON: Good question. Bill, are you down?

MR. RAUGHLEY: NRR needs to answer that.

MR. CAMERON: And who are we going to go to, not NRR but Research?

MR. ALEXANDER: No, this is NRR.

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

MR. ALEXANDER: Oh, yeah. That's all right. Oh, I'm not insulted. Maybe research is. I don't know.

(Laughter.)

MR. ALEXANDER: But I'm perfectly happy to be part of either one of them as long as I can, you know, make a contribution.

Anyway, no, that's one of the maintenance rule related questions, I think, and of course, it's information that we want to know in general for the generic letter, but quantitative and qualitative are both valid kinds of information. If it's something that you can't quantify, then what we want to know is from that if we don't concentrate on loop frequency per se, are there seasonal variations however you define the reliability and availability of off-site power and in your specific area.

We recognize, for instance, that looking at national averages that seem to show there's more loop events in the summertime may be misleading because some plant in certain areas may have more stressed conditions at other times perhaps due to reduced generation capacity, such as in Southern California in the wintertime, for example.

So what we want to know is, and qualitative is fine, what are the variations in grid reliability and availability and off-site power availability that you see in your area, if you see any.

If the answer is there aren't any, then that's a valid answer.

MR. CAMERON: Okay. Great. So in other words, I'm not sure the way it's phrased, but the intent of the generic letter would allow specific companies to answer that question based on their specific situation about what do you see as variations in grid reliability.

It could be seasonal. It could be something else?

MR. ALEXANDER: The intent we wanted is to get the story on that from each individual plant. That's why we're sending it to everybody.

MR. CAMERON: Okay. Thank you very much.

Let's go to Southern California.

MR. ROSENBLUM: This is Dick Rosenblum, again.

Going to the exact same questions, I'm

going to try to honor the way the question was asked. Is there anything in the generic letter that we'd like clarified or changed?

The same Question 5, I guess it's (c) and (d). The one point I would make is I would like to be sure that the questions being asked are precisely the questions that are intended to be asked, and I say it for this reason.

There is an imbedded assumption that somehow grid stress relates to loop frequency, and some of the data I heard and some of the discussions I heard in this session pointed out that loop only occurs when the plant is operating by the definitions we're using -- station blackout. Excuse me. And plants tend to operate in California more in the summer. So the frequency will go up.

I'm not sure what's what was really intended. If the question is really about the grid, then it doesn't matter whether the plant is operating or not. The grid has a certain number of events. They do include losses of power whether the plant is operating or not. That's one set of data that responds to one question: what's the grid doing?

Firm load interruptions, rolling blackouts, service interruptions, service reliability has nothing to do with that, and all of the presentations, both Gary's and William's, had service reliability interruptions in them that are not germane in my personal opinion.

So we have to be really careful, and I would ask people to go back and look at the generic letter and make sure the question you're asking, which we will answer, is precisely the question that's intended to be answered and that the data will then be used to answer that question, not say because plants operate more in the summer than in the winter, the grid is less reliable in the summer. Those two things are not related.

So we have to keep the data sets consistent, and we have to make sure that we bring to bear the data that really applies to the question being asked.

I'm not sure. I think among the experts that's occurring. I'm not sure among the decision makers that's occurring.

MR. CAMERON: Great, and that goes back to the point you brought up earlier about grid reliability versus system reliability.

Does the NRC staff have anything that they want to say on that issue? I think it's exactly the type of thing that we're looking for a comment on. Anybody want to say anything about that? You don't need to. I'm just giving you an opportunity.

Research or NRR this time?

MR. ALEXANDER: Whatever, as my son likes to say. No, it doesn't really matter, but in this case, yes, NRR still, I hope.

No, seriously, if you take a look at Question 5(c), it says there a seasonal variation in the stress on the grid in the vicinity of your nuclear power plant site. Is there a seasonal variation in the loop frequency?

We didn't mean to assume that there's an iron clad causal relationship between those two. We'd like to get both sets of data. We'll maybe then try to decide what it means, but we'd like to know are there seasonal variations in the stress on the grid.

Question D maybe should have included the stress part also, but that's the intent. We want to find out, and we also, at least in the staff we recognize the difference between service reliability and grid reliability.

We're concerned about grid reliability in terms of what's available to the nuclear power plant to maintain the safety buses for whatever event, and so we want to know if there is a reason, for example, in July at a given plant, which maybe is more of the average, to factor in something to your grid risk assessments that is not needed at other times of the years. Maybe there isn't, but that's what we're asking the question for, is to find out.

MR. CAMERON: Does that explanation help, Dick? And should there be any words added of clarification along those lines into the GL?

MR. RASMUSON: I think that answer does help, and it's what I perceived by listening to this whole discussion, but I do believe the GL needs to be clarified about exactly what question is being asked and what that means.

So for instance, don't tell us about service reliability issues. What is grid stress? You know, what is a loop? So that the people that answer the question that's truly intended.

MR. CAMERON: That's great.

Yes, sir. It's Dan?

MR. GOLDSTON: That's right. Dan Goldston, South Carolina Electric & Gas.

In Slide 4, number four from Dr. Rasmuson's and Raughley's presentation, they gave some definitions of loss of off-site power and station blackout, and then later on you seem to imply that the station blackout definition may be incomplete because you only address that if the plant was on line. That's not in the definition in your slide, and--

MR. RASMUSON: No, loss of off-site power can occur at either where the plant is either up or shut down. It is loss of off-site power to the safety bus irrespective of whether the plant is up or down.

MR. GOLDSTON: That's all safety buses. Okay. So that's clear on that.

Now, station blackout, wasn't that the one that you did say it mattered?

MR. RAUGHLEY: Yes, sir. If you look at the definition of station blackout in the regulations, it starts with the turbine trip. It's the loss of all AC power following the turbine trip. That's when you have the decay heat. When you shut down, you don't have much.

MR. GOLDSTON: So perhaps it would help me at least if the definition that we used here was exactly the same that we used elsewhere in all the other documents, including the generic letter, because I just got confused. I didn't realize that there was that discrepancy.

MR. CAMERON: Okay. Is there any reason

why we can't be consistent?

Okay. Well, I guess the point is taken, right, Ronaldo? Do you have that?

MR. JENKINS: Sure.

MR. CAMERON: Okay. Before we go over to San Onofre, let's go to Paul.

MR. GILL: Yeah, I just want to follow up on the --

MR. CAMERON: Paul Gill.

MR. GILL: Paul Gill.

-- station blackout.

PARTICIPANT: NRR.

MR. GILL: NRR. Thanks.

The definition for station blackout is loss of all AC power to the safety buses, excluding the batteries. Okay? So if you have battery power inverters, they're not part of the station blackout definition. It's all AC power that is from the off-site system as well as from the on-site system to all safety buses.

So that's the basic definition that is used in the rule.

MR. CAMERON: Okay. Thank you. Thank you, Paul.

If we need to go for clarification on

that, we will. Let's go to this gentleman, Parviz Moieni from San Onofre. Again, as Dick said.

Question 5(c), it seems we are talking about risk. What is the staff expectation that -- who is the best group at the nuclear power plant to answer this question? Do you think this is -- because this is risk assessment. So usually PRA group has a role. Do you think PRA group can answer this question or this should go to the grid people?

And what type of data we should look at to answer this question? Because right now I'm looking at it, and I thought I could answer this question. Right now I don't think I can answer this question. So who is going to answer this question?

And a second part of my question is that maybe they can answer this question. We saw a lot of viability, seasonal variability and low plant duration. Do you have information also on the regional like western grid, eastern grid? Are they sensitive through the seasonal or this is just an overall the nation's frequency and duration?

MR. ALEXANDER: Let me answer the first question. The answer is yes to your first question. In other words, any group at the plant that has meaningful information to contribute we'd like to get that incorporated into your responses. PRA can answer part of it. Operations can answer part of it. Anybody that's got useful information to contribute, we'd love to hear about it. It doesn't have to come from one group.

MR. CAMERON: Okay, and if you need to put a finer point on that, maybe we can discuss that off line with Steve.

Quickly, anything on the regional issue?

MR. RAUGHLEY: Yes, we do have sorts or you can sort the data to show the differences between the eastern Texas and the western interconnection, and I divided up, you know, had the two NERC bins there, you know, NERC definitions I've been following.

And then the events in the western interconnection are largely capacity events and events in the eastern interconnection are largely operating reliability. So you've got both ends of the spectrum, depending on where you are.

MR. CAMERON: Okay, great. Thank you, Bill.

We're going to take two more questions, and then we'll break for lunch and we'll figure out where we are on this when we come back from lunch.

But let's go to -- it's Phil and then

we'll go to Jennifer.

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

This one, I'm looking at the data that was provided on like the grid disturbances, the forecasts as far as capacity margin, TLRs. All that data is dated, and I'm not sure how we are going to relate it to our specific plant and be able to then give any sort of information back.

It appears you've used that to look at a summer, you know, as being the worst time frame, but yet it could be very much regional as where the problem is in the grid, and therefore, you know, the question may be that when you look at this data, it would be to get much more specific as far as what region, what location had the problems with load flows, had problem with these disturbances to get a better feel for what we need to be then in our response.

MR. RAUGHLEY: We agree. I just shared four or five slides. I was told to keep this to 15, 20 minutes, and as I mentioned, I'll give you the -- what we do have is on our Website. It's ML043000125. So if you want to -- ML043000125.

MR. CAMERON: I'll write that on the flip chart, too, for everybody.

But let me ask a question of Mr. Alexander again. In terms of that question, the response you gave before about as perhaps needs to be clarified a little bit as you discussed, but your explanation from before about looking for variations, is that relevant to this gentleman's question or am I off the mark here in terms of what we're looking for? Does that help him out any?

MR. ALEXANDER: Well, what we're looking for is we might be able to, from the data that we get from each individual plant, in our discussions which, of course, will be ongoing with Research and with EPRI, the data that we get or the information that we get if it's not, you know, in the classical form of data per se, but any insights that we can gain from the responses from each individual plant, from that information we might infer some patterns that could emerge about regional differences as well, and I think this question was focusing on regional differences.

And we already have some information as was already said about what some of the different causes of things are in different regions being related to operation in one area more so and historically related to generation capacity losses in other areas.

And maybe patterns like that will emerge when we start to get the information. So the answer is I guess until we sort of see the data we don't know if there's going to be a correlation necessarily that's identifiable region to region.

MR. CAMERON: Okay. Thank you very much.

And we're going to go to Jennifer for her comment or question, and then we're going to take a break. Keep in mind I think Bill said a Website this -- when you go to our Website, this ML number is an accession number for the so-called ADAMS system. Okay? Just in case you might be confused.

Jennifer.

MS. WEBER: Just real quick, if I'm understanding what you're trying to accomplish here, maybe focusing on seasons is predetermining the answer you're going to get whereas what Mr. Vine said was things like reserves can be a very important function, and I'm wondering if I'm understanding it correctly if what you're trying to get at in C&D is to ask are there definable periods of inquired risk to off-site power adequacy, for example, seasonal variations or low reserves, and -- okay. That's it.

Oh, and just to mention that stress on the grid is not necessarily -- having the grid not stressed doesn't mean you're off-site power is good. That's important to capture also, is not periods of grid stress. It's periods of off-site power vulnerability, I think is what you're trying to get to.

MR. CAMERON: Okay. Thanks, Jennifer. Thanks for that suggested language, and we'll go to Steve again, which I think which Jennifer is saying is consistent.

MR. ALEXANDER: Yes. As a matter of fact, what she's saying is very consistent with the intent, and perhaps we can, you know, craft some better language, but the point is that we would like to know what periods of time during the year, whether they're related to particular seasonal conditions or not, do you experience consistently for whatever institutional or historical reasons a higher probability of problems with off-site power? And we'd like to know that, and then we're going to wonder if that needs to be factored into routine risk assessments at certain times of the year because you have some reasonable expectation of the risk being higher at that particular time for whatever reason.

MR. CAMERON: Okay, good. Thank you.

I think that was a positive discussion, and let's not lose track of the long-term recommendation that Alex Marion brought up at the beginning of the discussion, but let's go for lunch.

I have about 25 to one. So if you can get back here around 1:30, we'll be on time, but we won't start exactly at 1:30.

(Whereupon,at 12:34 p.m., the meeting was recessed for lunch.)

AFTERNOON SESSION

(1:40 p.m.)

MR. CAMERON: Just as a point of order, I think that was a good discussion on the risk insights panel. We're going to start with our next panel on Transmission System Operations.

If there are further issue related to the risk insights panel, we'll pick those up tomorrow at some point, but we have a distinguished panel, and we wanted to get them on at the time we said we were going to get them on, and we're going to go with Ronaldo Jenkins from the Nuclear Regulatory Commission who is going to go first. He's with at least at this point Nuclear Reactor Regulation.

Okay, and then we're going to go to Susan Court, who's the Director of the Office of Market Oversight and Investigation at the Federal Energy Regulatory Commission.

Next we're going to David Nevius, and he's the Senior Vice President at the North American Electric Reliability Council.

Then we're going to go to Frank Koza with PJM, and we're going to finish up with Sam "Jimmy" Erven from North Carolina, but with the National Association of Regulatory Utility Commissioners.

And, again, we're going to run through the panel, and then we'll give the panelists the courtesy of questions or comments on what the other panelists said, and then we'll open it all up to you.

So let's start with Ronaldo.

MR. JENKINS: My name is Ronaldo Jenkins. I'm the Branch Chief of the Electrical Engineering Branch in the Division of Engineering. I work for Mike Mayfield.

Just a few remarks. I didn't want to take up anymore time from the other panelists. The purpose of this workshop is to hear from you, hear your comments, any kind of feedback you might have, and that's sort of why I was kind of holding back, wanted to jump out of my seat on some of the questions that were being asked this morning, but that would have meant less time for you to make your comments.

So I'd just like to encourage you to kind of let everything hang out, what you feel needs to be changed, but in order to make any clarifying changes to the GL, we do need specific comments, and so if there is language that is confusing that might lead you to an unintended consequence, please let us know and we'll certainly factor that into our deliberations.

Thank you.

MS. COURT: I wanted to make sure I had all of the electronics down here correct.

Good afternoon, ladies and gentlemen. My name is Susan Court, and I am, as indicated, the Director of the Office of Market Oversight and Investigation at the Federal Energy Regulatory Commission, and for the purposes of this statement in this presentation, I'm going to refer to the Commission, my Commission, as the FERC to avoid any confusion with your Commission, Ronaldo.

I've been a member of the FERC staff for about 24 years, and have held a variety of positions. Before becoming the OMOI Director a couple of months ago, I served as Chief of Staff and had the honor of signing the memorandum of agreement between the NRC and the FERC. Accordingly, I'm very pleased to participate today in this workshop on the proposed GL on grid reliability.

At this time I'd like to introduce two of my colleagues who will also be available to answer questions. Mr. Bruce Poole, sitting in the front row, is an engineer with the FERC's Division of Reliability in the agency's Office of Energy Markets and Reliability.

Ms. Demi Anas is an attorney with the FERC's Division of Enforcement in my office, OMOI.

As you may know, the FERC is currently engaged in crafting rules to create an electric reliability organization or ERO and develop procedures to establish, approve, and enforce electric reliability standards.

This rulemaking, by the way, is mandated by the Energy Policy Act of 2005, which we call around the FERC "EPACT." We're very clever people, we people at FERC, EPACT.

As a member of the FERC's Reliability Division, Mr. Poole has been involved in that effort, which is pending final agency action. Mr. Poole was also very active in the FERC's efforts following the 2003 blackout, which in large part prompted the FERC's involvement in reliability matters before the passage of EPACT.

Ms. Anas was very instrumental in developing the FERC's Standards of Conduct, applicable to electric and natural gas companies subject to the FERC's jurisdiction.

As it is our understanding that the request to have the FERC participate in this workshop was primarily sought because of the operation of those standards and their impact on off-site power, I will briefly describe the standards of conduct and the provisions that the FERC has made with respect to nuclear facilities.

In November 2003, the FERC issued a final rule on the standards of conduct for transmission providers. That's the title of the rule in an order entitled Order No. 2004. So you'll hear these two terms used interchangeably, Order No. 2004 or standards of conduct.

The rules became effective on September 22nd, 2004, and the regulations are codified in Part 358 of Title 18 of the Code of Federal Regulations, for all of the lawyers in the room. I know lawyers like to know about those CFR things, right? Right.

In brief, the standards of conduct govern the relationship between FERC jurisdictional natural gas pipelines and electric public utilities, which are referred to as transmission providers, and they're marketing and energy affiliates.

Now, a very brief FERC 101, the FERC's jurisdiction is over natural gas companies. The sale for resale of natural gas in interstate commerce and the transportation of natural gas in interstate commerce and also the facilities, natural gas facilities. We have a licensing or certificate function with respect to natural gas companies.

The FERC's jurisdiction with respect to electric utilities is over the sale for resale of electric energy in interstate commerce, and over the transmission of electric energy in interstate commerce, and because of EPACT, we also have backstop authority with respect to the siting of transmission facilities.

Anyway, going back to the standards of conduct again, standards of conduct apply to these transmission providers. That's natural gas pipelines and electric utilities and their marketing and energy affiliates.

A marketing affiliate is a transmission provider's energy sales unit, unless the unit engages solely in what we would call a bundled retail sale. Again, FERC's jurisdiction is over wholesale sales. State commissions have jurisdiction, as Jimmy will point out to you I'm sure, over retail sales.

An energy affiliate is an affiliate of a transmission provider that engages in or is involved in transmission transactions, manages or controls transmission capacity of a transmission provider, buys, sells, trades or administers natural gas or electric energy or engages in financial transactions relating to the sale or transmission of natural gas or electric energy.

So generally speaking, the transmission providers' affiliates, and there are some major exceptions like local distribution companies that sell at retail, natural gas at retail are not covered under this definition of affiliate.

Now, the standards of conduct are designed to prevent these transmission providers from granting undue preference to their marketing or their energy affiliates. They require the transmission provider, one, to function independently from its marketing or energy affiliates, treat all transmission customers affiliated and nonaffiliated on a nondiscriminatory basis, and, three, operate its transmission system in a way that will not unfairly provide benefit to its marketing or energy affiliates.

Our enabling statutes, by the way, the FERC's major enabling statutes are the federal PAR Act from 1935, and the Natural Gas Act from 1983, and they're rather simple, straightforward statutes. They basically say that companies can only charge just and reasonable rates and may not discriminate or unduly discriminate in the provision of their sales or their transportation or transmission services.

So these rules really are grounded in these fundamental principles, especially the prohibition against undue discrimination that's found in these 1930 depression era statutes.

The standards of conduct also require a transmission provider to insure that employees of its marketing or energy affiliates have access only to information available to the transmission provider's transmission customers, namely information posted on the company's OASIS, or open access same time information system.

The FERC requires electric transmission providers to post on the OASIS, their OASIS, a variety of information to give all users of the open access transmission system access to the same information.

As relevant here, the FERC has adopted several exceptions to the constraints on communication between transmission providers and their marketing or energy affiliates.

First, under emergency conditions, a transmission provider may take whatever steps are necessary to keep a system in operation. That's a pretty simple, straightforward proposition. Under emergency conditions, a transmission provider may take whatever steps necessary to keep a system in operation.

Thus, under the circumstances like those experienced in August 2003 during the blackout, a transmission provider would be permitted to engage in any type of communication and to share any employees needed to keep the system in operation.

Subsequently, the transmission provider would be required to report to the FERC each emergency that resulted from any deviation from the standards of conduct.

Also, as a general matter, the FERC permits a transmission provider to share with its marketing or energy affiliates information necessary to maintain the operation of the transmission system, and this information is defined as information necessary to operate and maintain the transmission system on a day-to-day basis, but does not include transmission or marketing information that would give the transmission providers market or energy affiliates undue preference over the nonaffiliated customers of that company.

Of particular note here, the FERC has explicitly stated -- now say that ten times fast -- the FERC has explicitly stated that this exception covers nuclear plant operators.

During the rulemaking proceeding leading up to the issuance of Order No. 2004, one commenter expressed concern that nuclear plant operators belonging to an energy affiliate of a transmission provider would be prohibited from receiving information they need to satisfy certain requirements of the NRC's regulations.

The commenter also pointed out that station blackout rules require that nuclear stations have real time information on disturbances and duration of power unavailability under Title 10 of the CFR, specifically Section 5063.

In Order No. 2004, the FERC ruled that the transmission provider would be provided to share this type of information with its energy affiliates.

The FERC has also permitted transmission providers to share with generation dispatch employees information necessary to perform such dispatch provided that such information does not include specific information about individual third party arrangements.

In sum, the FERC's standards of conduct are intended to prevent the communication of commercial information that would give a company's affiliates an undue advantage in the marketplace. They are not intended, definitely not intended, to impede necessary communication between operators of the transmission systems and nuclear power plant generators.

On behalf of the FERC, Chairman Joseph Kellaher and other members of the FERC, I thank you for inviting my colleagues and me to participate in this workshop, and of course, we'd be happy to answer any of your questions.

MR. CAMERON: Thank you very much.

And if you could, please, Dave.

MR. NEVIUS: And if you could put my slides up, please.

Thanks, again, to the NRC for inviting me to be here. I apologize for my voice. I t's either a change of life or I'm reaching puberty. I'm not sure which it is.

This is an extremely important subject, and one in which NEC has been involved for some time. Certainly the August 2003 blackout which has been mentioned here a number of times drew increased attention to grid reliability, especially regarding off-site power for nuclear power plants.

I'd like to highlight a few of the things that NERC has done and is involved in today that are relevant to this issue.

Next slide.

The four topics I'm just going to touch on briefly and then hopefully open it up to you for questions, what we're doing in our reliability readiness audits and what we've learned from those; some collaborative studies that we're conducting with the NRC staff, the status of the off-site power reliability standard that NERC is developing, and a study that was done by one of our regions, the Southeastern Electric Reliability Council on the transmission nuclear interface.

Next slide.

On the reliability readiness audit, this program was initiated in March of 2004 to address specific issues raised by the August 2003 blackout. In many respects, this program is similar to the INPO evaluations program. The differences are that we will publish or we do publish the results of these audits on our Website.

To date we've conducted audits of well over 100 regional reliability coordinators, RTOs, ISOs and other transmission grid operators. Thirty-four of these by my count have been systems and entities that have nuclear units within their footprints.

Early on we added the transmission grid nuclear power plant interface topic to our audit questionnaires and to the on-site visit agenda. There were some good practices that we've identified with regard to this interface, and some areas for improvement that we've also identified.

Some of the good practices, several utilities and transmission operators have special EMS alarms and displays that give a higher category of importance to situations where post contingency voltages at nuclear safety buses may fall below tech spec limits.

Also, one utility in particular, which we cited as an example of excellence, that's American Electric Power, has a special nuclear power plant voltage adequacy load flow program that they run every 30 minutes. The details of this are also on our Website.

Some entities set more conservative system voltage limits at the place where the nuclear plants are connected to their system, and then lastly, a number of utilities have rather specific interface agreements which include individualized voltage support guidelines.

One point that I didn't put on here that I should have is that a number of these agreements require regular coordination meetings, sometimes weekly, at least monthly, between the transmission grid operator and the nuclear plant operator.

Next slide.

Some of the things that we found that we felt were in need of some improvement, and again, these audits began in the spring of 2004. So some of these issues have already been addressed, that is, communication of nuclear power plant voltage requirements to the transmission system operators.

So the operator of the grid knows what those limits are. Also, more detailed modeling and monitoring of the post trip voltages at critical buses in the nuclear power plant using real time contingency analysis or other similar analysis programs.

There are some examples. I think Frank Koza will talk about one of them where there's some more detailed modeling of the specific loads in a power plant so that the grid operator can actually determine when critical safety bus voltages may fall below limits under various contingency conditions.

And then as Susan Court mentioned, improved understanding of the code of conduct exceptions for nuclear power plants. That was an issue that we've heard about in a number of places, and I'm glad that she was here today to clarify that.

All of these readiness audit reports are posted on our public Website, www.nerc.com, pretty simple.

Next slide.

I also signed a memorandum of agreement with the NRC. The basic agreement was signed in August of 2004, and then I signed four appendices in June of 2005. One of those appendices is a coordination plan for the exchange of operational experience data and information. It describes how NERC and NRC staffs will communicate and cooperate regarding the assessment of grid performance data over time to identify changes, emerging trends, potential vulnerabilities, local problems, statistics, probabilistic risk assessments, et cetera.

We're working with the NRC staff to include the nuclear power plant operating parameters in all regional and interregional study work and collaborating on these technical assessments of grid performance, and after the discussion just before lunch, I think we do need to make sure that this work looks very closely at how we count things.

There's lots of data, but we need to be smart and intelligent about how things are counted and categorized.

We're also looking to expand some of the grid models to represent the nuclear power plants in more detail, and Frank Koza will talk about this pilot project at Susquehanna Nuclear.

The next slide.

One of the most important initiatives, I think, that NERC has underway is developing a standard on off-site power reliability. NERC was requested to develop this standard by the Nuclear Energy Institute's Grid Reliability Task Force because of changes to grid operation brought about by industry deregulation and restructuring and because of recent operating events. Some of these have been touched on earlier today and are covered in the INPO addendum to SOER 99-1 and in the topical report TR-440.

The standard will address required coordination between nuclear power plants and transmission system operators to insure safe operation and shutdown of nuclear plants. The standard will have certain requirements that apply to nuclear plants, to transmission owners and operators, to transmission planners, reliability coordinators, et cetera.

Next slide.

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

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

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

The next slide.

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

You'll see the address on the Website. It's easy to find if you get to the NERC Website.

It's incumbent upon all of you whether you work in a nuclear plant or you're a grid operator, even folks in the NRC. We welcome any and all comments on this standard. I think the way it is drafted it addresses many of the issues that were brought out in this morning's discussion.

I should say that if things go as we expect and we get through several drafts of this standard and we have a ballot of the standard, we would propose the effective date to be around July 1 of 2007.

The last point I want to make is a study that was done by one of our regional counsels, the SERC region. I noticed there are several folks from that region here today both from the nuclear plant side and the grid operating side.

SERC is one of eight NERC regional liability counsel members, and they launched this initiative in October of 2004 to investigate the interface between grid operations and nuclear power plant operations. It's significant because SERC includes over 30 nuclear units within its footprint. The study focused on interface practices, enhancing safe and reliable operation of the plants and off-site power supply, the unique aspects of nuclear power plant operating requirements, and then to share noteworthy practices within the region and with other regions in four areas, which are listed here.

Last slide.

The white paper, which is somewhat restricted distribution I understand right now, does have a number of areas identified for additional study. They are to investigate the interface with the large RTOs and independent transmission operators and independent transmission companies as opposed to the individual utility transmission operators; to address code of conduct issues regarding communications between transmission operators and nuclear plants; to look at standards for real time tools and model validation; and finally, training and education for improved communications between transmission operators and nuclear plant operators.

And I'll conclude by saying I think the word "communication" was used many, many times today and it should be used many, many times as we go forward. There is no substitute whatsoever for learning what happens in the other person's work environment.

Grid operators need to know what's going on in a nuclear plant control room and nuclear plant operators need to know what goes on in a system operations control room. That would go a long way, a long, long way to addressing many of the concerns and issues that we're all here to solve.

Thank you very much.

MR. CAMERON: (Speaking from an unmiked location.)

MR. KLECKLEY: Okay. Thank you very much, Chip.

And I would also like to thank the NRC for the opportunity to appear before you this afternoon.

I'm going to speak about voltage control for the nuclear power plants in PJM. It's a topic that is criss-crossed throughout the generic letter. Our thoughts and comments about how PJM does it are mandatory here.

I will say this at the top though. This certainly isn't the only way to do things, and this just happens to be the PJM way of doing it, and there are certain other acceptable ways to conduct business.

The first slide, please.

Just a couple of introductory comments about PJM. If you could just focus your attention on that pie chart on the right side of the slide, in PJM nuclear power is approximately 30 percent of the energy in PJM. So nuclear power is an extremely important portion of the PJM marketplace.

The next slide, please.

The next slide kind of indicates all of the nuclear units in PJM. There are 31 separate units, and I'm going to touch upon that a little bit later.

The next slide, please.

I want to, I guess, pay a small tribute here to the people within PJM who do most of the work, and it's not necessarily PJM. We have a very active group of the nuclear generation owners. That group meets on a monthly basis. We have active participation from all of our nuclear owners, and a lot of the things and improvements that PJM has been able to put in place have been at the encouragement and support of our nuclear owners.

The process basically is the nuclear owners work with the PJM staff and our operating committee. Our operating committee is basically the non-nuclear generators plus the transmission owners in PJM.

Any kind of new requirement that the

nuclear generation owners would bring forward are vetted through that committee structure, discussed with all of the parties and then agreed to and then entered into the PJM manuals.

Next slide, please.

Okay. This is basically our obligation to the nuclear power plants with respect to voltage control. We're to operate the system within limits, and even if the nuclear power plant has more restrictive limits, we're to operate to those limits as well.

The tools we use, real time contingency analysis, a real time contingency analysis application is basically running 4,000 separate contingencies in PJM and it runs about every minute.

Beyond that, we are reactively limited in PJM, which means there's a finite amount of transfers we can reliably handle going from west to east across the system. Therefore, we have a second application called transfer limit calculator that is running every five minutes and basically calculating the maximum amount of transfers we can handle from the west to east perspective.

Now, beyond those tools, and Dave mentioned in his talk we are I'll say peeling the onion back one more layer with respect to the modeling of the nuclear power plants. We're working with PPL, Susquehanna, and what we're going to try to do there is beyond the real time contingency analysis. We're going to go deeper into the plan and basically model the emergency buses at Susquehanna and for the purpose there of running and making sure that we're able to handle even post accident loads in a reliable manner.

Next slide please.

These two slides or this slide basically summarizes the voltage standards in PJM. The one that's in the upper left are really our baseline voltage limits, and they apply to all facilities in PJM.

The one in the lower right are basically documents, our actions that we take for any kind of voltage situation. So all of these things are well documented, well understood, all published, all public information that both the nuclear power plants, PJM, and all of the market participants know about.

Next slide, please.

In one of our PJM manuals, that being manual M3, transmission operations, and the link for that is at the bottom of the page here, it outlines the mitigation protocols that we have in place for nuclear power plant voltage limits. Basically it's a three-step process. There's a lot of communication, and the communication goes from PJM to the transmission owner who is connected to that plan, and then out to the plan itself.

A lot of communication, a lot of information being shared.

The second aspect of this procedure is that we do respect the special needs of the nuclear power plant to have the actual voltage information. So to dovetail Susan's comments, we've made exceptions here for the idea that we need to share additional information to the nuclear power plants that we ordinarily would not share with others.

And the final thing is taking action. We were one generation out of its economic merit order. If we are in a situation where we are at least simulating a violation of the voltage limit, so we'll do what we need to do in the economic dispatch to take care of those things.

Next slide, please.

I do have one example here. This happens to be the Exelon example. We have a number of combat area nuclear power plants. This basically summarizes the process that we go through right now with Exelon to manage.

They have a series of higher voltage requirements than the baseline that I showed you earlier. Anyway, PJM builds the conditional contingencies in our real time contingency analysis to monitor post contingency voltage.

Then we were running, as I mentioned, we were running this calculation about every minute. If we determine that we'll have a simulated violation, we will contact through the transmission owner a person on the Exelon staff who's the nuclear duty officer. This is an on-shift nuclear person who will have the decision making authority.

Once that person is contacted and made aware of the voltage situation, they can either authorize us to run a generation or they can take action at the nuclear power plant to mitigate the problem, and down at the bottom side, if the NDO does authorize generation, then PJM will put additional generators on as necessary to mitigate that post contingency voltage within limits.

And if the limit is violated, then Exelon goes into an LCO until the post contingency voltage is brought within limits. Like I say, that's an example of the actual practice we're using for the Exelon plants in the combat area.

Next slide, please.

Just a couple of words about our outage coordination process. Maintenance risk assessments are mentioned significantly in the generic letter. A process in PJM is that the plan outages are submitted many times almost a year ahead of time to PJM. A consideration is made and PJM has the ability to, I guess, accept the request of any kind of outage request. I'm sorry. We can accept or reject any outage request.

And then the real activity begins like one to seven days from the start of the outage where a repeating set of analyses are run to make sure that given the configuration of the grid and the situation with regard to economic dispatch, that we can still accommodate that outage reliably.

And then on the outage start date a final analysis is done right before the equipment is switched out of service to insure that we can handle that out age reliably. So there's a whole multiple step process that goes into place to make sure that we can accommodate nuclear outages reliably.

Next slide, please.

Now, I want to shift gears a little bit

here in the spirit of Ronaldo's comments about providing feedback about the generic letter. I've got a series of questions here, and the format of these is the italicized part are the words out of the draft generic letter, and then I posed some questions, and I just want to mention that this comes from the perspective of the grid person who doesn't necessarily know the details of the intent, I'll say, of the nuclear regulation, but like I say, I would just like to offer these up as questions as I'll say an uneducated grid person looks at the generic letter.

The first topic, degraded grid reliability conditions, and I know in the generic letter there is a definition provided of what that means, but that definition, if you will, is kind of in nuclear terms. So as I step back and look at that, the questions that I have are kind of in the middle there.

Could a degraded grid reliability condition be any kind of circuit breaker maintenance in the substation? Could it be outages of any adjacent transmission lines? Could it be any routine maintenance on the protection systems? Could it be any high load conditions?

I would submit to you that any one of those activities in some fashion increases the risk for the nuclear power plant. The question is interpretation. You know, the intent of the generic letter was to address things like that.

And my further question is and who decides that. I believe the generic letter places that in the hands of the licensees to decide, and my only question there is the licensee may not be a good judge of the grid risk, and I can tell you for sure that we aren't a good judge of the nuclear power plant risks. It gets back to kind of Dave's point. There has got to be significant communication here.

And, I guess, my point here would be that maybe there's some further definition of these points that needs to be in the generic letter because conceivably you could take somewhat extreme interpretations of that term.

Next slide, please.

The next topic is about basically when to do maintenance, and I guess it kind of puts on the licensee the responsibility to potentially reschedule maintenance based on degraded grid conditions.

I think in the earlier sessions this morning we talked about -- and I don't want to get into that discussion about whether there's more risk in the summer or not -- but anyway, you could get to the situation where -- and I'm going to jump to the bottom one -- you would not do maintenance in a high load scenario. That is, in the winter or the summer when there's high peak loads, you would not do any maintenance at all.

The flip side of that is -- and those of you who are involved in the grid know this, I guess -- in the maintenance season in the spring and the fall there is a lot of equipment out of service, a whole lot of equipment, and I guess if you're looking at it from a risk perspective, that's also a risk factor. Is the grid degraded, so to speak, in that facilities are out of service that you would not entertain doing nuclear maintenance in those periods.

So you can do the math there. If you take the spring and the fall and the winter and the summer away, that doesn't give you much time left.

So I don't want to be, you know, trite about that, but I mean, you do have to be -- there's a consideration to think about the ability to do maintenance and to do it with the minimal amount of risk.

Next slide, please.

The next topic I want to just briefly talk about is formal agreements. One could interpret the words in the generic letter to assume a separate agreement, if you will, between each nuclear power plant and their transmission owner. All I would tell you about that is in PJM what we have is like umbrella agreements that each member of PJM signs, is legally bound to, and establishes the requirements in our PJM annual for compliance.

So I just would offer out to the staff that hopefully you're open to that kind of an agreement kind of scenario as opposed to either bilateral or trilateral agreements between the nuclear power plant owner and the transmission owner and potentially the TSO.

Next slide, please.

The next topic has to do with the periodic check-in. I know as was mentioned, I guess, from Dick from -- I'm sorry. You mentioned that this morning, whether there has to be a periodic check-in.

In reading the words, I was also concerned about that in that it does seem to imply that the nuclear power plant should be calling their transmission system operator on a periodic basis to make sure everything is okay, so to speak.

I just put the numbers up there. We have 31 plants. We have eight owners. We have 16 transmission owners. We really don't need to put a call center in place for the transmission owners, and as funny as that sounds, I just hope that exception reporting in our minds would be the way to go here and not, in essence, calling periodically to make sure everything is okay, and I just hope that the NRC folks are --

(Applause.)

MR. KLECKLEY: Thank you.

I hope they're in favor of that as a way to go.

My last slide has to do with the recommendations in Reg. Guide 1.155, and I guess it talks about what I'll call local power sources that could be put into play here in a restoration activity. The point I wanted to make here was it's very difficult, I guess, to guess or analyze every conceivable restoration scenario. In a situation where the nuclear power plant is located immediately adjacent to some other kind of black start facility that could be used in a restoration, I think that's pretty easy to work with.

The thing is though and the point I want to make was there are so many combinations of what could be in service, out of service, available, not available so that in the restoration scenario, it's too simple to say that you're immediately adjacent generators would be employed to facilitate your restoration.

In PJM we already give deference in our procedures in our manuals to the importance of establishing feeds into the nuclear power plants. They go basically to the top of the list, and I just want to be cautionary about the idea of specific generators being tied to certain restoration scenarios.

I think this is way too complicated a picture to deal with in that situation. If you look at even the August '03 blackout, there were portions of the system on the edges that were very strong and could be immediately employed to start the restoration procedure, and we just have to be careful about that.

I think a lot of the restoration literature has been based on a total blackout in a very wide area, and I think what we've seen most recently is that there are portions of this system that are strong around the areas that are blacked out and can really accelerate the restoration activities that way.

So my guidance here or my thought is not to be necessarily so specific about how the restoration would be conducted, except to say that we want to give deference to the nuclear power plants in the restoration scenario.

And with that I will conclude and certainly be happy to answer any questions that you have in the other period.

MR. CAMERON: Thank you, and I know we'll be going back to those thoughts. (Speaking from an unmiked location.)

MR. ERVEN: Thanks, Chip.

As has been said several times, my name is Sam Erven or Jimmy Erven. I'm a member of the North Carolina Utilities Commission. I also serve as Chairman of the Committee on Electricity of the National Association of Regulatory Utility Commissioners and since everything has an acronym, ours is NARUC.

In addition, I also served as chairman of the nuclear issues and waste disposal subcommittee of the NARUC electricity committee from late 2002 until early last year.

I'm speaking today on behalf of NARUC and do want to thank the NRC for the opportunity to come today and be with you.

NARUC, for those of you who don't know, is the national organization of the state commissions responsible for economic and safety regulation over the intrastate operations of regulated utilities. So as Susan said, we do the intrastate retail regulation in general. They do the interstate wholesale regulation. It's not always easy sometimes to find where the line is there, but those are sort of the black letter law principles that we all follow.

NARUC's members have the obligation under state law to insure the establishment and maintenance of such energy utility services as may be required by the public convenience and necessity, as well as insuring that such services are provided at just and reasonable rates.

Our members include the governmental agencies in the 50 states, the District of Columbia, Puerto Rico, and the Virgin Islands charged with regulating rates, terms, and conditions of service associated with the intrastate operations of electric, natural gas, water, and telephone utilities. So we're kind of generalists. We're not specialists like virtually everybody else here is.

The statement that I'm going to give you today is an update of one that was provided to the NRC by my colleague Commissioner Burt Garvin of Wisconsin. On that occasion he described a resolution for state action on mandatory reliability standards, which NARUC adopted on February 16, 2005.

That resolution encouraged state commissions to consider making compliance with existing NERC reliability standards mandatory under state law. We adopted this resolution because at that time, and for some considerable time before that, Congress had not passed legislation authorizing the development and enforcement of mandatory reliability standards.

NARUC has consistently supported legislation that would result in the implementation of a mandatory reliability regime, given the interest that all state commissions share in the preservation of a reliable bulk power system.

As you know, the Energy Policy Act of 2005 -- and we call it EPACT, too -- was signed into law on August 8, 2005. Section 215 of the Federal Power Act, which was enacted as part of EPACT, provides for the creation of the electric reliability organization that both Susan and David referred to.

The ERO under this law would have the authority to adopt and enforce mandatory reliability standards. NARUC, as we've said a number of times, applauds the adoption of this reliability provision, and we have attempted to assist in its implementation to the greatest extent possible.

On September 1, 2005, the FERC -- and I'm going to call them "FERC" because that's just the way I do it -- issued a notice of proposed rulemaking for the purpose of developing rules governing the operation and approval of an ERO as contemplated under Federal Power Act Section 215. In the NOPR, the FERC proposed regulations addressing a wide variety of issues, such as the criteria that an entity must satisfy to qualify as an ERO, the procedures that must be followed in an enforcement action by the ERO and by FERC.

The criteria under which the ERO may agree to delegate authority to propose enforced reliability standards to a regional entity in the manner in which the ERO should be funded.

Prior to the issuance of the NOPR, NARUC was glad to participate with certain other interested parties in an attempt to try to work out some of these issues in advance, and I think most people believe that was a fairly useful preliminary process.

On October 7th of 2005, NARUC filed

comments addressing the issues raised in the reliability NOPR. In our comments we urged the FERC to recognize that the NERC currently develops minimum national reliability standards through an open stakeholder process; that there are differences in the design of the bulk power system in different parts of the country; that regional reliability organizations currently implement the national standards promulgated by NERC in a manner consistent with regional conditions; and that the FERC should build on the existing structure in implementing the new reliability legislation.

Although NARUC recognized that existing regional reliability organizations are going to have to adopt and implement certain changes in their operations in order to be eligible to receive delegated authority from the ERO, we urge the FERC to allow the existing regional reliability organizations the opportunity to transform themselves into the regional entities envisioned by the EPACT in order to preserve the existing storehouse of regional reliability information and to provide continuity to the new organizations.

The logic behind our emphasis upon the importance of preserving a significant role for regional entities, I hope, is obvious. Historically regional standards criteria and rules had gone beyond the bare minimum level needed to prevent cascading blackouts and have attempted to provide other reliability requirements intended to insure that local problems didn't develop into major ones as a result of the intention.

The current allocation of responsibilities recognizes that a national organization lacks the detailed local knowledge of system events and conditions necessary to effectively implement and enforce reliability standards that exist at the regional level.

Similarly, a national organization lacks the regional knowledge of local system design, demographics and requirements necessary for customized regional reliability rules.

As a result, while NARUC fully supports enforcement of the provisions that call for the adoption and enforcement of minimum national reliability standards, NARUC also believes that the differences among regions necessitate a significant role for regional entities and that FERC should recognize this fact in the final rule that's adopted in the reliability rulemaking.

Our participation in the reliability rulemaking proceeding has not been limited, however, to the filing of comments. On December 9, 2005, the FERC held a technical conference that dealt with the reliability issue, and we were privileged to be permitted to participate in that proceeding. My colleague, Commissioner Alan Freifeld of Maryland gave a statement on behalf of NARUC at that time, and he stated that the states have a significant role to play in the maintenance of reliable electric service, and pointed out the provision in EPACT that specifically preserves the rights of states to act to insure the safety, adequacy, and reliability of electric service within the state's boundaries, as long as that action is not inconsistent with the reliability standard developed by the ERO and approved by FERC.

As a result, in our view at least, responsibility for the maintenance of a reliable bulk power system is shared among state, regional, and federal and national authority.

We look forward to the adoption of the FERC's reliability rules and hope we'll be able to continue to participate constructively in the process of implementing this very important piece of legislation.

In our statement last year, we informed you that there's a close relationship in many ways between NARUC and NERC. For several years, a number of our state commissions have actively participated in the NERC standard development process. We have tried to encourage more of that in recent years and adopted a resolution that was approved by the NARUC Board in July of last year that called on states to join the NERC registered ballot body and to participate in the development of and the casting of informed votes on electric reliability standards applicable to the bulk power system.

Since NARUC adopted that resolution, at least two other state commissions have taken the steps necessary to participate in NERC's standard development processes. NARUC believes that state participation in the development and approval of reliability standards will and should continue in the future.

At present NARUC and its members actively participate in NERC in several ways. NARUC and various states are active observers of NERC's activities. NARUC and at least several individual states are registered as voting members of NERC.

The states have two representatives on

NERC's standards authorization committee, which develops reliability standards. States have two representatives on NERC's compliance and certification committee, which is the enforcement arm of NERC.

The states also have representatives on such NERC standing committees as the planning committee and the operating committee. State regulators and staff also participate in regular NERC briefings that are held by Webcast. Recent briefings have focused on questions such as proposed changes to NERC's reliability standards and industry compliance with existing standards.

Finally the states have representatives on the NERC stakeholder committee.

In addition to our activities within NERC, we also participate in the activities of the North American Electric Standards Board, which for those of you that don't know what NAESB is, it's a body that attempts to develop uniform business practices for electric and gas industries.

Within NAESB NARUC has attempted to insure that the standard business practices that are developed by that organization don't undermine reliable bulk power system operations.

Finally, as we indicated in April of last year when Commissioner Garvin was here, the National Regulatory Research Institute, which is affiliated with NARUC, had performed a survey about individual state actions to insure liability at the distribution level. A written version of these remarks is, I think, somewhere floating around the room and there's a summary of the survey results that are available if anybody is interested in looking at them.

Chip, that concludes my prepared remarks. If we haven't totally anesthetized everybody by this point, I'll be happy to answer any questions that anybody may have.

MR. CAMERON: Okay. Thank you, Jimmy.

And thank all of you.

You just heard a lot of valuable information about grid reliability, and it goes beyond the immediate issue of discussion, which is the generic letter, but we do have the experts, the resources here. So I would just say take advantage of that if you have questions about grid reliability generally.

But we are here to discuss the generic letter and Frank Koza was kind enough to give us some specific examples of some language in the generic letter that may be problematic. So don't lose that focus.

I would give the panel an opportunity for any questions between panelists, including any comments that any of you might have on Frank Koza's slides, and maybe just in anticipation, if we could just put the last three or four slides from Frank Koza's presentation up there in case we need them.

But, panelists, anything? Ronaldo, you have something?

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

Susan, I'd like to thank you for your presentation on the standards of conduct. At the February 2005 INPO, EPRI, NEI workshop in Atlanta there was quite a bit of comments from the participants basically say that, you know, FERC rules prohibited us from sharing information, and I was just going to follow that up with a question.

Is there anything with respect to the generic letter that the FERC rules prohibit the nuclear power plants from getting that information from the transmission system operators?

MS. COURT: Actually I can't speak to the generic letter itself because our participation, as you may know, was relatively late, and so as far as actually studying the generic letter, vis-a-vis our specific requirements, I can't speak to that, and I apologize for that. I don't think my colleagues can either because I don't think we have really had the opportunity to look at it from that perspective.

However, I don't know where they were coming from, to tell you the truth. Because my understanding from what the RECD has said about this, there should be no impediment in communication between the nuclear plant and their affiliates.

So maybe there was just a general statement like that. It's hard to kind of address, but the FERC specifically addressed that concern in one of its iterations on those topic.

Order No. 2004 was not just a single order. It was actually a combination of orders that were issued over a year and a half period. So maybe they missed that version. I don't know.

MR. JENKINS: Thank you for that clarification.

MR. CAMERON: And Ronaldo, before you go on, let me ask whether David or Frank has anything that they want to add on on that issue.

Okay. Thank you very much, Susan.

MR. JENKINS: You had a slide up there that basically indicated that standard would be mandatory compliance. Is that mandatory for nuclear power plants? And exactly how does that dovetail with regulatory requirements?

MR. NEVIUS: Well, as the DRO if we establish a standard which we submit to FERC and the provincial regulators in Canada for their approval, once that approval is given, the standard is applicable to all of the NDs that are called out in the standard.

In this particular case, the draft calls for compliance with the standard by generation owners, transmission order, operators, et cetera. So, yes, it would apply to nuclear generator ownership and operators.

MR. JENKINS: Is there any deference to NRC requirements or do you consider them above and beyond?

A similar question that you had this morning about INPO's standards of conduct being higher.

MR. NEVIUS: Yeah, I don't think there's anything inconsistent. Terry, don't hide behind your pad this time. There's nothing inconsistent in the draft standard with NRC requirements as far as I can tell. Do you?

MR. CRAWLEY: No. The intent is to actually reinforce that so that mainly the primary responsibility the nuclear power plant owner has in this is, number one, to clearly communicate its requirements to the transmission planners, operators, and so forth so that they understand them. Okay?

As Dave mentioned, I think a lot of the problems have been just communications or maybe lack of understanding of communications because communications were not concise, and of course, this involves more than just written. You know, you can have a requirement to have a written agreement, but you can only put so much detail into that agreement.

So the standard is not intended to go to that level of detail, but it's really to get the two or three or four -- actually there are going to be multiple parties as you well know now with the way the deregulated industry is structured. So it's to bring those parties together to make sure that those requirements, whoever they apply to on the transmission side, are clearly communicated

Now, obviously, the nuclear plant owner has other responsibilities as well, such as related to the maintenance rule as far as communicating that type of information.

So we've tried to cover all of that within the standard really, as you said, to dovetail the regulatory requirements back into the transmission side so that they get factored into and not overlooked by the transmission planners and operators when they're doing their thing.

So we'll take a second look at it, but I don't see anything at this point.

MR. CAMERON: Okay.

MR. CRAWLEY: Anyone else who's involved on the development of the standard, if you have any thoughts on that, please speak up.

MR. CAMERON: Okay, and that's Terry Crawley.

MR. CRAWLEY: Sorry. Terry Crawley. I'm with Southern Company Generation, representing Southern Nuclear here.

MR. CAMERON: Thank you, Terry.

MR. JENKINS: You'll be hearing from us regarding our comments on the standard.

MR. NEVIUS: Ronaldo, one point because it came up in discussion this morning. One of the specific requirements placed by this standard on transmission NDs is to inform nuclear plant entities when the transmission entity loses the ability to assess the operation of the transmission system affecting the nuclear plant interface requirements.

And that was brought up specifically this morning. So basically if Frank loses his eyes and ears on what's going on in the system, he would be obligated to let the nuclear plants know that he can no longer tell what their post contingency voltages would be, right?

MR. JENKINS: And, Frank, what would your response then be?

MR. KOZA: Well, we've got two responses. First, if we lose our EMS system, we have a backup EMS and a back-up control center. So we would relocate the operating staff for that backup control center, fire up the backup EMS, and probably be in business within like 30 minutes.

Now, within that 30 minute period, we also have our transmission owners who run the same kind of software that we do, can do those calculations, and we would basically hand off to them those calculations and make sure that they informed the nuclear power plants until you're up and running again.

MR. JENKINS: Okay. One other question for you, Frank. In terms of action levels, emergency action levels that you outlined there, is the role in blackouts or load shedding actions that will be taken -- that's considered an off normal?

MR. KOZA: Well, I think actually July 27th would be a good example to just step through briefly. July 27th we ended up calling a five percent voltage reduction in Washington and Baltimore.

One thing we do have is we do have a Website that publishes all of the emergency procedures. So anybody, you know, the general public can see all of that stuff.

We communicated heavily with both our transmission owners and the generation owners on that day about what we were facing in this area, and even though we had a lot of capacity to the west of us, we had difficulty delivering into Washington and Baltimore.

So to me that's the more likely scenario of an emergency situation. At no time were any of the nuclear power plants in this area at any kind of risk. We did at one time consider if the load continued to increase, and if you'll remember that day I think it was like 98 degrees here and so on, but basically we're in a situation where the next step we would have considered would have been a load shed, but we would have done the load shed to protect the reliability of the system.

MR. JENKINS: Okay. Thank you.

MR. CAMERON: Ronaldo, is that the extent of your questions of the panelists?

MR. JENKINS: yes.

MR. CAMERON: Any of you want to talk to any of the others before we go to the audience? Susan.

MS. COURT: I don't want to talk, not that I wouldn't want to talk to you gentlemen. I'm sure it would be a very interesting conversation.

(Laughter.)

MS. COURT: The one thing I just thought I'd mention because I can now mention it even as I speak, the FERC is issuing a press release indicating that it's going to consider the ERO rule at a special meeting on February 2nd. So for timing for the ladies and gentlemen in the audience, you might be interested in that rule that Jimmy just described and also has been mentioned by several of us here, will be considered by the FERC on February 2nd.

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

Let me ask all of you. Our agenda called for a break at 2:45. Of course, that was based on coming back at 12:30. I think we're going to go on for a while before we take a break if that's okay with everybody.

And I know that some of our panelists have planes, et cetera, et cetera. So let's try to take advantage of them being here.

So I'll open it up to all of you. Let's go to Mr. Thorson.

MR. THORSON: James Thorson from Detroit Edison.

I have a question, I guess, for Frank. It's related to my previous question, and that is, you know, if I get a phone call from yourself saying, "Gee, we've lost our RTCA," what kind of actions would you expect the utility to have the capability of doing in the event of that notification?

MR. KOZA: I can tell you the transmission owners at PJM all have real time contingency analysis and are doing virtually the same calculations that we are. Obviously we're focused on the bulk power system. They are focused on the lower voltage, but I'm pretty confident all of them can duplicate the post contingency voltage calculations at the nuclear plants that are necessary.

MR. THORSON: So we're being required to

ask the next question, which is: what if they can't?

MR. KOZA: You mean if we lost both>

MR. THORSON: Yes, sir.

MR. KOZA: Well, I guess that's where you go into your LCO and that kind of thing.

MR. CAMERON: Can I just check that assumption that Mr. Thorson put out there when you said we're being required to go beyond that? Can you -- being required by what?

MR. THORSON: Well, if you look at I believe it was two, "Charlie," but I don't have my notes here, there seems to be a strong suggestion that in the event of loss of the total RTCA, that the utility is required to perform an operability determination, and I guess I'm deeply struggling with what we would do in that operability determination because we do not have the capability to duplicate your either regional or local RTCA.

MR. CAMERON: Is this your question about operability versus risk? Ronaldo, can we?

MR. JENKINS: Well, I guess the main point of that question is going back to essentially the first question, which is that the first question says, well, I have agreements. I have communication with my transmission system operator who is acting for me to basically make that operability determination for me.

They are saying that they are providing me with off-site power, and that off-site power will meet my needs.

Then if you run into the situation where a tornado or some other catastrophic event takes them out, then the nuclear plant is sitting there operating, and the question is: well, what is the change in status?

Now, you know, there is this discussion on the real time contingency analysis versus anything else. If you are using something else, then we would like to know what that something else is, and I want to stay away from trying to tell you what the answer is or what we specifically would say, "Okay. You should come back to us with this particular answer."

But there have been examples, for example, Southern Cal Edison, where they use nomograms. They have analyzed and basically developed an envelope in which their plant operates within, and as long as they stay within that envelope, then they're okay, and so if in a situation that you lost your computers, then we go as engineers back to our manual, more primitive types of calculations that we use, that we rely on. So that would probably be an example of something that would be okay.

Does that answer your question?

MR. CAMERON: This is the issue, and we're going to go here now. Obviously it's an appropriate time. This is the issue that Mr. Thorson brought up before, that there was a lot of murmuring on after we heard the NRC response to it that's in the parking lot. Let's keep going with this and see if we can illuminate it a little bit more.

Yes, sir.

MR. JURY: Yeah, Keith Jury from Exelon.

The question on inoperability evaluation, I mean, obviously we had a discussion very early this morning that not all plants have an RTCA or analogous system, and the generic letter does -- I agree with Mr. Thorson -- it does imply that if you do an RTCA and it does become unavailable, that there's an expectation that you do an operability determination which has very specific meaning to those of us at the nuclear power plants.

What I just heard you say was that you would go to some sort of a manual method to try and determine what your voltage is. There's a huge difference between an operability determination and that impact in doing a manual evaluation with whatever tools you have available for your voltage, and I think that that definitely needs to be clarified in the generic letter.

MR. CAMERON: If I could ask you, is there any easy, simple language that you would recommend that the NRC put in or is it more complicated?

MR. JURY: Well, I think it's more complicated. I guess the question after I've heard the full benefit of the discussion that the NRC is asking is what will you do, if anything, if you lose your RTCA, and I think that's a fair question.

I think to tie it to the operability of off-site power even implicitly is not what I heard the intent to be, and I think that earlier when you heard the murmuring, I was one of the murmurers, and the reason I murmured is because you're not going to necessarily default to say we need to do an operability evaluation on off-site power unless we've had one of the by exception phone calls telling us that we have a problem before they lost it.

MR. CAMERON: So you might change 2(f) to just very simply say what would you do if you lost your RTCA. All right. Okay.

Let's go right here. Yes, sir.

PARTICIPANT: Well, Keith pretty much

asked the same question, but I'll take it a step further. You have 31 nuclear plants using the same RTCA potentially, at least in our region potentially five or six. If we enter into operability issues associated with the loss of an RTCA and you've got six plants that basically end up with both off-site power sources being declared inoperable, I think that's the last thing we want in a situation like that to have to deal with it.

MR. CAMERON: Okay. Thank you.

We have some other comments here. This is Phil, I think.

MR. BRADY: Yeah, Phil Brady, PPL-Susquehanna.

I guess when plants were originally licensed we didn't necessarily have these RTCAs. They were licensed based on studies and analysis, and I guess my position would be that if you ever got into this type of position, you'd go back to your studies and your analysis to confirm that your operation of your system is still valid, and you're basically in a stable environment.

MR. JENKINS: That's right.

MR. BRADY: And they haven't said that they've lost the capability to monitor the grid.

They've just lost the capability to run the software package. That's all we're talking about here, right?

MR. KOZA: That's correct, and there are also -- we would go to off-line power studies, but you know, everybody just needs to understand it's not going to be as accurate as the real time information. That's all.

MR. JENKINS: Right.

MR. CAMERON: Okay. Great. Let's hear from one of the NRC staff. Tom.

MR. KOSHY: This is Thomas Koshy from Electrical Engineering Branch, NRR.

What we are trying to find out, the higher goal is when the transmission system operator tells you that my program to predict what your off-site power supply will be is not work; when you hear that news, if you continue to believe unless I hear from him everything is fine and I have my off-site power, that's wrong. We shouldn't be reaching that conclusion.

Now, Ronaldo just explained to one of the cases where they have a nomogram which they have analyzed and confidently determined that nomogram and voltage indication is adequate to predict what the off-site power will do given a plan a trip. So if you can do an analysis and develop such a nomogram in which you have confidence that if the plan trips you will have the off-site power capable of supplying the whole base and capacity, that is an alternate approach.

We heard from PJM that they have their own back-up and further downstream transmission system has the same, similar program running in a more limited area with its own backup. That would be very nice.

But in certain parts of the country when you do not have such layers of protection, we need to rely on some analysis. For example, I know about the Palo Verde area. They have certain basic analysis outside which they do not operate because they know in the past years of experience they have done the worst case analysis and said this guarantees sufficient off-site power for our stations.

So there are cases when such analysis will remain good, but why are we bringing up this, you know, contingency analysis programming that took place? Because based on the percent market situations, your sale of power and which way the power is flowing is decided probably the previous day or maybe on the same day, depending on other contingency conditions that rise us.

So can you predict all of those conditions and the variations in the power flow given that you have to assure that the off-site power remains operable?

So in those cases where you cannot make such predictions effectively, you may need to think of having such a software so that you have a higher confidence in making better predictions for your off-site power.

I hope that explains.

MR. JENKINS: The issue is not whether we asked the question or not. The requirement to insure that systems, structures are operable is a truism. That's the way we run plants. So the only question is if I'm relying on a third party to provide me with assurance they are totally competent, they've been doing this for years. They are the experts. I don't have the capability to do that.

Then when they tell me that they can no longer do that for me, then responsibility then resides with me to figure out what to do next, and so, you know, that's pretty much where we are, and whether it's a -- one of the things about the real time contingency analysis program we've struggled with within the staff is that it's very dependent on the particular area you're located in. If you're in an area of the country in which your power flows are fairly predictable, you know pretty much whether it's -- I hate to use the word "seasonal" here -- but whether from time to time they change, but they're certainly within a certain range, the staff has accepted bounding types of analysis.

But the reality is that there are plenty of places in the country where things are changing quite a bit. I think Bill Raughley's presentation showed the increase in the number of TLRs, which is an indication of congestion on the system. So that's just a reality of where we are.

So I think we can clarify the question if need be, but that's about all I can say about that.

MR. CAMERON: Okay, and we did hear a suggested clarification or a simplification on the question.

Let's take a couple more points on this and then see if there's another topic related to this panel.

Did you want to say something, Mr. Thorson?

MR. THORSON: Yeah, just one more, I guess, clarification, but I think one possible solution to this is to move this question out of the operability area and into the risk area. If you consider that situation where your RTCA is lost as an area of increased risk, then a utility has the capability of handling that within their maintenance rule and they can make some relatively intelligent decisions of what work they might do, what they wouldn't do, what they would back out of, and I think that gives you a greater, I guess, confidence level that the direction of safety has been approached rather than simply heading into an operability area.

So I guess that's just my two cents.

MR. CAMERON: Okay. Thank you for that suggestion.

Now, we're still on Subquestion 2(f). We're going to go to Alex and then we're going to go to Paul Gill.

MR. MARION: Alex Marion, NEI.

I would recommend that those three, four slides that Mr. Koza presented identifying points of clarification from the transmission system operator be considered as changes to the generic letter.

MR. CAMERON: Okay. Well, definitely I think Mike Mayfield is shaking his head affirmatively that they will be considered as suggested changes to the generic letter at this point.

Paul, did you have something that you wanted to add on this 2(f)?

MR. GILL: Yes. This is Paul again.

I want to follow up on this question about 2(f). I guess we all talk about if you lose your RTCA. Certainly Ronaldo and Tom mentioned that you may have other means to assess the off-site power system.

Now, given that if you don't have any of those means and you have no information, you need to look at and see, you know, is that system operable or not.

Now, it may or may not be. The question is do you now -- the question is does the NPP conduct an off-site power system operability determination.

Okay. Now, we heard from PJM that when the RTCA program for Exelon predicts voltages are going to be below the nuclear power plant requirement, they go into an LCO. As a matter of fact, we have had notification from Exelon plants they exactly did that last year. As a matter of fact, three different times.

Now, if you're in this --

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

run generators to boost the voltage.

MR. GILL: True, but I'm just saying that they have entered the LCO. All they did was enter their tech specs. Now, if you are sitting blind because you don't have the RTCA and you don't have any other means to predict what the voltages are going to be, the question that we are asking is: do you enter into determining your operability or not?

Okay. We're not saying that you declare your system inoperable. We're saying what do you do. Okay? The gist of the question is do you make an operability determination.

Okay. Now, if you look at and make a determination, gee, you know, voltages are not going to be there, you enter your tech specs until the problem is corrected.

MR. CAMERON: Okay. Let's take one more comment on this. I think we've really been getting some good comments on it, and we have some time tomorrow to continue the discussion, but I just want to make sure that we don't lose track of other issues.

Did you want to?

MR. GRANGER: Yeah, this is John Granger, FPL, Florida Power & Light. I'm sorry.

In that scenario I just wanted to question what if your diesel generator were out of service at that point? Then you would enter a one-hour shutdown LCO, which is definitely not where we want to go.

So I think that I agree with putting it in the risk determination versus the operability.

MR. CAMERON: Okay. Thank you very much.

Okay. We can come back to this if we need to. Now I just would -- I know that Jimmy Erven is going to have to catch two trains, a bus, and whatever to get to his airplane. Are there any questions or comments for Jimmy?

Okay. Well, stay with us and just enjoy yourself.

(Laughter.)

MR. ERVEN: I'm having a great time.

MR. CAMERON: All right, and we heard from -- Alex, go ahead. There is one question for you.

MR. MARION: Alex Marion, NEI.

I received a couple calls over the past couple of months from utilities who were expressing concerns of actions being taken at a state level that may go above and beyond what NERC is planning to incorporate in certain standards or codes of practice. Is there a protocol there or is there a priority where one overrules the other?

Where would a utility go when that kind of thing comes up?

MR. ERVEN: There's a provision that we refer to in the reliability legislation as a state savings price, which says, in effect, as I indicated earlier, that a state can adopt reliability rules that are not inconsistent with those approved by the ERO so that, for example, if a state chooses to, it can adopt a consistent reliability rule.

If someone to whom that rule is subject believes that, in fact, the rule is not consistent with the ERO's pronouncements, there is a provision within which the person subject to that rule can apply to FERC, if my memory is not failing me, for a determination of consistency or inconsistency.

That's obviously a protection that's built into the system to make sure that states don't put operators in the position of choosing which of their two sets of regulators they're going to choose to comply with. That risk shouldn't exist on the bill.

MR. CAMERON: David, anything?

MR. NEVIUS: No, I think the specific example, Alex, is New York State has some more --

MR. MARION: I wasn't going to mention that.

MR. NEVIUS: Well, I will.

-- more specific standards, and they came about after the 1977 blackout, and they consider under certain higher risk situations, under thunderstorm conditions that they'll operate somewhat more conservatively.

Now, that's not inconsistent because it certainly serves to enhance reliability and protect reliability.

MR. ERVEN: And there actually is a specific sentence in the state exception clause that allows New York to do some things that other states are not allowed to do. Sine I haven't read that in a couple of months I can't tell you exactly what it is, but there is a New York specific provision.

That commission has been very interested in reliability rules, as Dave said, ever since the blackout.

The other thing that is probably worth noting is that many of the western state commissions have been very actively involved in trying to persuade FERC to allow the west to do certain things on an interconnection-wide basis. I think what's going to come of that effort really is up to Susan and her colleagues, but that sort of tension is out there as well.

MR. CAMERON: Okay. Thank you very much.

As we noted, the suggestions, the questions that Frank Koza put before us are going to be considered by the NRC, but let's see if any of you have anything to say on these particular slides. Now, I think this is the first slide, Frank, that you had with --

MR. KOZA: It's the second one.

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

Here's the first one which basically pointed out -- go back the other way. All right. One more. Okay. Degredated -- what are degraded reliability conditions? Could they be these four things? Who decides?

Anybody want to add anything on that particular slide to us? Tom, do you want to say?

MR. KOSHY: This is Thomas Koshy from Electrical Branch.

Secure regular maintenance at the substation. If that is a substation immediate to the new glass stations, when you do maintenance on it, does that increase the possibility of causing a plant trip? Or if that increases the possibility of losing off-site power, that does make a difference, and that decision needs to come from the transmission people.

I can quote you examples if you look at the operating history. Well, I think it was Beaver Valley they were doing substation maintenance. They lost both units and the off-site power.

So it depends on the maintenance and the transmission company needs to characterize what is the level of risk from that maintenance activity. If you can fully isolate that break in maintenance in a way that it will not cause the plant to trip or take the off-site power, then you could consider that to be an acceptable risk.

So essentially that is kind of our higher goal when you look at how you need to be sensitive about the maintenance activities that happen in the switchyard.

The same case with the protection systems. If you are testing the protective lane for the incoming lines or outgoing lines and if you think ripping those protective relay by actually injecting a current in it can influence the logic in a way it will take a ring bus out, that is significant and that causes challenge to the plant trip as well as the off-site power.

These are the type of assessments that

both parties need to make, and in the side of transmission and switchyard, the transmission people are more acute and experienced in that area. So that input needs to come to the nuclear station from the transmission site, whereas if it is a break that is within the control of the nuclear stations, they need to make that assessment.

So that is kind of the idea behind, you know, having those discussions in general.

MR. CAMERON: Okay. Thank you.

MR. KOZA: If I could respond to that.

MR. CAMERON: Go ahead, Frank.

MR. KOZA: The reason I have those up there, Tom, just so you understand, routine maintenance of protection systems, relay technicians go into substations all the time doing what seems to be very innocuous maintenance activities, and I've seen them take out. So I mean, is that to say we never let the relay technicians in to do calibrations?

Because I would say to you any time they're in that substation control room, they have the potential to trip the plant and cause mayhem to start.

MR. CAMERON: Okay. Any other important issues that someone wants to raise on this? And then we'll go through the rest of them just to make sure that we catalogue it.

Yes, sir.

MR. LUNSMIRE: Tim Lunsmire from the Nuclear Management Company.

A caution on this one. With the grid, since the grid operators or the TSOs don't really have PRA assessments like, say, the nuclear plants, and they don't necessarily understand how we do PRA assessments, how can the grid operators like in our area, mostly it's either they're within our voltage limits, yes or no, or the grid is stable, yes or no. When they do a particular activity on the grid, they look at it to make sure that, yes, they can go with the single contingency or even farther on, but they don't have the same sense of risk as a nuclear plant does where we go in the very detailed (a)(4) evaluations to say the equipment is operable or maintenance rule valuations for risk when we take that evaluation into account.

When we ask the grid operator how to do that, how does the staff like us to take that into account? Because they don't have the same philosophies as the nuclear plants do. So it's very difficult to make an evaluation of grid operability or grid risk of whatever the grid operator is doing because they don't have the same perspective as we do, as the nuclear plants.

MR. CAMERON: Okay. Thank you.

Frank looks like he's agreeing with that. Ronaldo, do you want to say anything in regard to that in terms of the generic letter?

MR. JENKINS: Well, I guess you get into this issue of trying to know the entire universe and respond to that in a single correspondence, and I don't think the staff is looking for that. I think that we're looking for known conditions, known situations, whether they come from a PRA study, whether they come from engineering studies that have been done by the licensee to identify vulnerabilities.

The idea, and I believe this is coming from the maintenance rule, is how do you factor that into, you know, making your scheduling of taking major pieces of equipment out of service. So Frank brings up a good point in that you can certainly drill down and you can find where a particular technician can cause a problem, but that's certainly not the intent of the generic letter to identify each and every instance that could potentially come up.

MR. CAMERON: That seems to be -- we've heard some similar discussion about some of the anxieties associated with the questions where we've heard the staff say that it's certainly not the staff's intent to do such-and-such. Maybe -- and I think you've heard the request for some clarification -- maybe there needs to be some bounding language.

MR. JENKINS: You know, it's very site specific, plant specific. There may have been PRA studies that have been done that identify certain circuit breakers that are particularly risk significant, and obviously, you know, you want to factor that into your overall risk management program.

But if you were talking about adjacent transmission lines, many plants have several transmission lines coming in and so that doesn't necessarily rise to a level of a degraded grid reliability conditions primarily because what you get to go back to is what's the definition.

You're looking for can I get power to the safety buses. If there's an activity that can interfere with that and reasonably interfere with that, then obviously that would be what we were looking for.

MR. CAMERON: Okay. Thank you.

And I don't want to necessarily rush you 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 grid at any particular point in time.

I heard today that that should not be an issue.

MR. CAMERON: Susan, before you answer that, can I just -- let me just get in response to this slide Steve Alexander on briefly and then let's go to you on that.

MR. ALEXANDER: Actually kind of as a preamble to this slide, could we go back to his first set of questions? Because they are really quite closely related.

We talk about degraded grid reliability conditions that would warrant the rescheduling of grid risk sensitive maintenance activities, and that's kind of related to the next one, and you asked what are those degraded grid reliability conditions.

What we'd like to know is what you consider degraded grid reliability conditions, how you determine if they exist, and what do you do about it if you find them. That's pretty much what it boils down to.

Could they be those things? Absolutely. Any or all of the above, and in fact, a reasonable answer to the question would be here's what we think are all the stuff that we deal with that could cause grid reliability problems, and that could increase the risk to the plant. Here's how we determine what they are, what the severity is. Here's how we deal with it. That's kind of what we want to know.

And so you suggest that those things could be any of those, and the answer is, yeah, sure, all of them possibly at any given time.

A very important thing at the bottom there. Who decides? Licensee may not be a good judge of grid risks in terms of what the possibility of losing the proper voltage and frequency on the grid at any given time, let's say, over the next few hours if there's some condition that might be perceived to be persisting.

And the TSO may not have an idea of what those risks are specifically to the plant and then how the subsequent trip of the plant would affect them.

So the answer who decides is they both do by talking to one another, and that's why we ask about agreements between the two, and some of the answers that you've suggested are in a general way the kind of stuff that we want to find out about. We're getting an opportunity to get the answers to some of our questions from you today.

We'd like to hear from everybody on the

same subject.

Can we go to the next one please?

If the grid reliability evaluation, however you do it, but the point is we think that you should do it, indicate that degraded grid reliability may exist during maintenance activities, yeah, I admit it. We think you should probably consider rescheduling things.

We certainly don't expect you not to do maintenance at all. That would be ridiculous, and maybe this was meant, you know, somewhat in a -- but we hope that --

MR. KOZA: I was going to an extreme there, no question.

MR. ALEXANDER: Yeah.

MR. KOZA: I didn't want to get to the point we were doing all maintenance at 4:00 a.m. on Easter Sunday. That's all.

MR. ALEXANDER: And your point is?

(Laughter.)

MR. KOZA: It's a risky time.

MR. ALEXANDER: It's a risky time.

Well, what we want to know is are you looking at the risks of those conditions, and are you deciding, you know, making conscious decisions about rescheduling maintenance if it looks like it's a prudent thing to do?

We don't expect you to say, "Well, it's risky, you know, from January 1st through December 31st. Therefore we're not going to do any maintenance." Obviously we realize that, but we think people should pick and choose intelligently their maintenance windows and what kinds of maintenance they do to minimize the risk.

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

And, Susan, you heard the gentleman's question. Do you want to talk to that?

MS. COURT: Sure. I didn't want to give the impression that you get a free pass if you're a nuclear facility. There are no free passes here.

What I talked about and mentioned were the two major exceptions to the general prohibition against sharing information between and among affiliates, first, in an emergency situation, and I wanted to emphasize and I do emphasize that there's nothing in the Commission's rules, there's nothing in the Commission's intentions that its standards of conduct rules would allow any impediment to a nuclear facility getting off-site power in an emergency situation. Absolutely not.

And then the second is the general exception regarding the sharing of information to maintain the operation of the transmission system, and the Commission has specifically spoken to the applicability of that exception to sharing of information between transmission providers and nuclear facilities saying it does apply.

That said, I am sure that the legal memo is very careful to point out all the other types of requirements that Order No. 2004 lays out. For example, the functional separation.

So there are a lot of aspects of the standards of conduct that I haven't addressed today, and because it was beyond the scope of this particular topic.

So the main point is that for general operation and for emergency situations there are exceptions to the general prohibition against sharing information.

Order No. 2004, the FERC's standards of conduct are intended to insure in a commercial sense, in a marketplace that affiliates of transmission providers do not get an undue advantage. The intention, the purpose behind those rules is not to impede operations. It's really an economic set of regulations or a set of economic regulations, not physical regulations.

So, again, I don't want to question or I wouldn't question the legal memo that a company has gotten because I'm sure it's on a much wider range of topics.

And two other things I'd like to mention. The Commission recently, I guess, at the end of the year posted, the FERC posted on its Web page a whole package of enforcement matters for the general public and the industry's information, and one part of that package is a list of frequently asked questions about the standards of conduct. So I just set that out for your information.

Also, recently the FERC issued an order which sets up a process where a company can seek information as to whether or not the Commission would institute enforcement action under certain circumstances. This is a no action letter process which other agencies, other federal agencies have used, and the FERC has just instituted that no action letter.

So if there really is a question in your mind, again, assuming we're not talking about an emergency, assuming that we're not talking about the average type of operational information, a company can always seek that type of advice as well.

MR. CAMERON: Thank you very much, Susan.

On this issue about what's the NRC vision of agreements, Ronaldo, let me ask you at this point. What's your take on Frank's questions on this in terms of what a licensee is expected to provide us in response to that question in the generic letter?

MR. JENKINS: We have been involved with the whole topic of grid reliability ever since the western grid disturbance in 1996, and you know, from our information visits to transmission system operators, NERC, FERC, we have view that anything is better than nothing.

And certainly the formal agreements provides a structure by which information can be exchanged. Now, we don't have a particular vision. I guess that's the answer to your question, nor do we have any restrictions or views that there's a limitation on agreements.

The idea is that a third party has responsibility. You've delegated responsibility implicitly to that third party to assure off-site power operability. From our view, you need to have analysis or you do some kind of post trip evaluation of the models that are being used, but in any case the only way that we know of assuring off-site power in this type of environment is by an analysis.

And so the third party has to make that call. So obviously communication, as David Nevius mentioned, is the key and it's important to have that. And so we're in a fact finding mode in terms of this generic letter. We're trying to obtain information.

MR. CAMERON: Okay.

MR. JENKINS: One other thing. During the northeastern power outage August 2003, I had just come out of a briefing of Commissioner Merrifield who was the Acting Chairman at the time, and coming out of that briefing, we found out that the event was occurring.

And so going to our NRC incident response center and you go in there and you say, "Well, what in the heck is going on? What is it, that we have a number of plants here that experienced loss of off-site power?"

So at that particular instant in time we did not know whether this was being driven by an adversary or whether or not we were dealing with a natural phenomenon or whatever. The main thing we were looking for was information, and I guess I would pose the question that assuming that we get through the clarification part of this generic letter, and everyone here is totally happy with the final product, suppose that generic letter information had been available prior to August 2003 and the staff had the responses back and we had information profiles on licensees so that when that event occurred, we would be able to know, hey, this is what should be happening right now.

I think we would have been in a much better shape to respond to that event.

MR. CAMERON: Okay, and we're going to take two more comments on this particular issue. Again, just from a facilitator's observation, it seems like there's an anxiety among people in the industry that there should be a correct answer to these questions, and what I keep hearing from the NRC staff is, "Give us the best information you can on this," that there's not necessarily a, quote, correct, unquote, answer.

But I think we all realize there's always a fear of what the regulator is going to do.

But at any rate, I'm going to go right back here and then come up to you. Okay. Yes, sir.

MR. NICELY: Jerry Nicely, TVA Nuclear.

Part of the question here, you have "promptly notify," and also question one, alpha is what's the time period for the notification.

I know the people running real time state estimator systems, I notice the PJM guy on one of his slides indicated that they had a time period between, I think, 15 and 30 minutes, if I saw the slide correctly, but I guess I'm assuming that it's acceptable. You know, should you calculate that should I have a trip of my nuclear unit and my voltage just may not be adequate, that you may want to run the eight minute cycle one more time to see if the condition cleared or possibly take action to try to alleviate it before calling the nuclear plant and shaking their day up.

I guess I just sort of want some opinion both from the staff and maybe what PJM is doing. You know, is it reasonable to allow the transmission operator some period of time to try to alleviate the situation before notifying the nuclear power, unless it's an actual degradation that's happening right then?

MR. CAMERON: Frank, do you have anything to say on that?

MR. KOZA: Just that the way we do it is we have up to 30 minutes to fix it. If we can't fix it, we'll put generators on. We will do whatever we have to do to fix it.

MR. CAMERON: Okay. Let's hear from Tom, NRC staff, and then I want to ask you whether you want to take a break for 15 minutes and then come back and finish with the panel or whether you just want to run straight through and try to adjourn by our four o'clock adjournment time. It's a question for you. Let's hear from Tom first.

MR. KOSHY: Could you put that previous page on?

The question was individual bilateral agreements between PJM and each nuclear power plant, bilateral with PJM.

Let me kind of clarify to you what is the higher goal. The higher goal is that the transmission people clearly knows what the voltage requirement is for each nuclear station. Speaking from operating experience, one developed unit station replaces their service water pumps in an outage. Once they came back on line, they found out that the voltage set points they have is not sufficient because the motors they replaced with are of higher horsepower and it started creating an under voltage such that the alternate source brought under voltage on that condition and then jumped back and both units tripped.

This is about ten-plus years ago. I'm just giving an illustration to explain my point because it is very important that the transmission people remain continuously aware of what the plant changes are that influence the acquired voltage for the particular station.

So we are not picky on how you make your agreements through a higher corporate level or a lower level so long as this intention is served, so that you have a continuing knowledge of what the exact voltage requirements are.

When the plant trips, 1,000-plus megawatts of generation switches to 15 megawatts of load, and when it changes like that, if you have capability to supply only the safety system loads, you cannot do a normal shutdown. You are going to increase the thermal expansion on the plant.

So you need to look in and see if you can make that available and the transmission people are clearly aware of the power demand when you actually stopped generating.

And you need to revisit that issue

especially when you make major modifications to the plant on service water pumps, on those large pumps that are circulating water pumps, and fully aware of that situation so that they can respond to the plant need, and that is the higher goal we are trying to serve.

And this is the question through which we are hoping that we can put a strong reminder in the industry to pursue towards a continuous update and a clear understanding on both sides what the expectation is.

MR. CAMERON: Thank you, Tom. I'm glad you're here to remind us of what the higher goal is on these, and I think it very useful actually for people to understand that.

Can I get a sense of we don't want to keep you here all day, but obviously if we take a break now, I think that we probably have a half hour more of discussion on this particular issue. Do you want to just march through till four or do you want to --

PARTICIPANTS: (Speaking from unmiked locations.)

MR. CAMERON: That's why I should never ask those questions.

(Laughter.)

MR. CAMERON: Yeah. I'll tell you what. How many for a break now?

(Show of hands.)

MR. CAMERON: Okay. I guess you can take one.

(Laughter.)

MR. CAMERON: But okay. Let's try to go through -- I'm sorry. Being facetious, but if you need to go out, just people do that and let's take the next half hour and continue to explore, and then we'll see if we can go.

Do you want to do something before you take a break? All right.

MR. REIMERS: My name is Greg Reimers. I'm with Pacific Gas and Electric, Diablo Canyon.

And I guess what I clearly heard now is the NRC acknowledges that it will be the transmission operator making operability calls for off-site power because if they predict voltage is going to be too low, we're inoperable. We and our LCOs, and I guess my question is, you know, the nuclear power plant operator seems like the passthrough for NRC requirements on the transmission operator with the higher goal in mind wouldn't it be more efficient since the NERC rules or proposed standards -- the comment period closes at the end of the month for nuclear off-site power issues from the NERC side of the fence. Why not wait until those rules are done and see what the transmission operators are really going to have to do?

MR. CAMERON: Ronaldo, I'm going to go to you on this one, and correct me if I'm wrong. The generic letter is asking for information about certain things.

MR. JENKINS: Correct.

MR. CAMERON: It's not saying that someone should do this or someone should do that.

MR. JENKINS: Right.

MR. CAMERON: Okay. Is that --

MR. JENKINS: That's correct. That's correct.

MR. CAMERON: Okay. Do you want to say anything else in response to this gentleman's comment or question?

MR. JENKINS: Well, I think that over the years we have -- the staff has been involved with off-site power issues almost going back in the licensing period, and whenever off-site power issues have come up, we have had licensees with their transmission system operators sitting in the same room.

I don't recall a single instance in which the transmission system operator was off somewhere else and the licensee is doing something entirely different with the NRC.

A case in point was Diablo Canyon. When Diablo Canyon as part of the California deregulation, there was the selling of Laurel Bay unit. The Diablo Canyon came in, and they came in with their transmission system organization, and they explained to us what they would be doing now that the Laurel Bay plant, which is identified in their FSAR as one of the units that needed to run in order to maintain proper voltage at Diablo Canyon.

They came in and explained to us what modifications they were going to make in order to insure that their plant would continue to operate at adequate voltages. Okay?

So basically, all of the generic letter is about that. It's about insuring that adequate power is provided to safety buses, and of course you know the times as spelled out in the technical specifications limiting conditions for operations, when that should be.

So you know, the NRC is not interested in regulating any transmission system operators or owners. I believe that David Nevius and then Frank Koza would be very upset if we were trying to impose any requirements on their organizations.

However, there is a responsibility on the part of the nuclear power plant licensee to insure that off-site power is operable during periods of operation called for under the technical specifications.

So I hope that answers your question.

MR. CAMERON: Okay. Thanks, Ronaldo.

We're going to go to this gentleman here.

MR. BONNER: John Bonner, Entergy Nuclear, Northeast.

A follow-up question on the FERC Order 2004. You talk about the sharing of transmission information with affiliate generators. Is that also part of merchant generators?

MS. COURT: Yes, yes. It really just depends on whether or not a particular company meets the definition in the rules. So first of all you have to start off with what's an affiliate, and that involves a question of control.

So if a company, an enterprise is affiliated with a transmission provider as "affiliate" is defined and performs certain types of functions or is not otherwise accepted from the rule, then yes.

So sometimes it's hard to answer that question generally because there might be circumstances, again, whether or not there's just a minimal amount of control that might trigger one of the exceptions to the rule, but it's possible. Let's put it that way.

MR. BONNER: So the intent is that it would apply to affiliates or from generators owned by a transmission company as well as generators that have no relationship to the transmission company other than they utilize their transmission --

MS. COURT: No. That's not an affiliate then. Remember this whole rule, the standards of conduct deals with relationships between a transmission provider and its affiliates. So a merchant generator that is not affiliated with the transmission provider doesn't trigger the rule. That's just a customer on the system. It's not an affiliate of the transmission provider.

So remember the purpose of the rule is to insure that the company, the utility that is transmitting the energy is not giving its affiliate an undue advantage by giving it information ahead of time or information that's not available to everybody else who also wants service on the system. So it has got a fairly simple, straightforward purpose.

MR. CAMERON: Okay.

MR. BONNER: Can I do a follow-up to that?

MR. CAMERON: Okay. Do a quick follow-up.

MR. BONNER: So if a generator isn't an affiliate of the transmission company, it's all right for that transmission company to provide information to the merchant generator that's not also available to other generators in the area?

MS. COURT: Well, remember there's a general prohibition in FERC's rules which come directly from the statutes that provides that a company has got to act in a not unduly discriminatory fashion vis-a-vis everyone.

In other words, if a company is giving out information that is going to, even though there's not an affiliation, it still has to treat everybody fairly. So there's an overall prohibition against undue discrimination.

So if a transmission provider is going to give information in the marketplace selectively and by doing so is going to discriminate, then the companies that are discriminated against might have a fair claim against that transmission provider.

But that goes to the overall statute. That goes back to 1938, which says that a public utility may not discriminate unduly in the marketplace.

MR. CAMERON: And, John, you may want to talk off-line with Susan or Susan's staff if you have some more specifics.

MS. COURT: Yeah, if there's a specific. Again, sometimes because of the control issue and things of that sort, just dealing with these questions in a vacuum is difficult.

MR. CAMERON: Okay. Thank you, Susan.

We have something else from Steve Alexander of the NRR staff.

MR. ALEXANDER: Thank you. Still, I hope.

I guess I've heard a general kind of concern here that we're expecting that nuclear utility plant operators to be able to have a free exchange of information that's necessary to safely operate the plant with their transmission system operators, and I've noticed a couple of times you've used the term "under emergency conditions."

And I guess I have to ask the question two ways. Is there anything that you've heard here in terms of the kinds of information that we would like to have licensees be able to get from the TSOs and the kinds of information that the TSOs would like to get from the licensees of nuclear power plants that would run afoul of your rule, and does the exception allow them to do that whenever they deem it necessary for safe operation of the plant, whether there's an emergency per se or not?

Because a lot of the stuff that we have to do is planning for contingencies. What happens if there is an emergency? There may be no emergency, but there is still some risk because your ability to cope with an emergency may be reduced.

So if there's anything, and I would also say that perhaps in the near future when you have a chance to review the generic letter in general we would need to know if there's anything in there where the utility could get in a bind in trying to serve two masters. There's no way that we ant that in any way to be able to compromise their to get all the information they need to operate safely.

MS. COURT: Well, I can assure you that the FERC does not want the business in the utilities to be serving two masters to a point where that's going to cause a problem.

Obviously you serve two masters. You

actually probably serve 100 masters with all of the other federal agencies and state agencies out there that you have to address.

But in any event, when I mentioned emergency, what I was laying out was that there's a specific exception in the rules for emergency situations, and so when I referred to emergency search, that's what I was talking about, a specific exception.

With a subsequent follow-up, in other words, a requirement that the utility then provide the information after the fact so that information sharing that would generally be prohibited, otherwise be prohibited could take place in an emergency situation with notification to the agency after the fact.

The other exception was the generally applicable exception for day-to-day operation. That type of information can be shared. As I mentioned, the rule's purpose is geared to prevent the sharing information that's going to have a commercial impact. That's what it's all about, and so that's why the Commission made the exception for the day-to-day operations.

The staff is very amenable to answering questions. That's why we created this frequently asked questions part of our Web site. So if a member of the industry has a specific question, we'd be more than happy to. We have a hot line or you can call the enforcement staff or you can call me, and we will try to provide an answer to your specific question.

Now, as far as have we heard anything today that would be problematic? I have -- I don't know, Demi. Have you heard anything that would be problematic?

MR. CAMERON: Okay. We're going to go to Demi.

MS. COURT: This is Ms. Demi Anas, who has worked very closely on the development of these rules.

MS. ANAS: And like someone else, I have a frog in my throat today. So I apologize.

I think the key thing that we haven't really focused on -- we've talked about the sharing of information -- is that we allow the sharing of that information, but the folks that receive that information are prohibited from passing it along to the folks who were involved in the commercial aspects of the business. We've labeled that as the no conduit rule.

So I think to sort of show the whole picture is, you know, we recognize that there's an operational necessity to share certain information. So we permit the sharing of that information, but prohibit the person who receives that information from passing it along to those who are involved in the real merchant activities, the selling or buying of wholesale power. So I hope that adds a little bit.

MR. CAMERON: Thank you, Demi.

Let's go to this gentleman. This is, I think, the last -- oh, there's two more? One more after this. Okay. This is an issue we talked about before about how often and under what circumstances do you just routinely are supposed to talk to the TSO, again, keeping in mind that there's not necessarily a right answer to any of these questions.

Yes, sir.

MR. FARKAS: Steven Farkas from the Westinghouse Owners Group.

To pursue this question further, a lot of the plants use a 12-week planning cycle to come up with their maintenance task. So this information that we would be asking from the TSO would be on the order of, you know, depending on what stage of the task planning we're in, could be up to 12 weeks ahead of time asking them, you know, is this switchyard going to be out? Is that substation, this breaker? Are you going to be doing relay work?

It's not, you know, day to day, you know, we got up this morning and at shift change we want to talk to the TSO and ask him what's wrong today. It's 12 weeks worth of knowing in the future what's wrong and the question is: are we allowed to get that kind of information from the TSO?

MR. CAMERON: Susan, this may --

MS. COURT: I don't know if we've actually specifically addressed that, but we have not.

MR. CAMERON: Does this have something to do with does there have to be an emergency or is there something that might be necessary to prevent an emergency, what is the day-to-day operations, what is that type of --

MS. COURT: I think it is probably more of the last. This is obviously not an emergency and the Commission's rules don't talk about sharing information to prevent an emergency as such, but clearly what's contemplated by the day-to-day operation is that you have to share information in order to insure that day-to-day operation. Whether or not this 12-week lead, specifically I don't think we have specifically addressed.

But, Bruce, did you have a comment on

that? This is Bruce Poole who works in the Reliability Division of FERC.

MR. POOLE: I guess I don't see how that comes into play because all of the TSOs would have their long-term planning programs, and anything that was going to be taken out of service that far away would have already been identified and should be listed.

MR. CAMERON: Yes. Did you have a follow-up question?

MR. KOZA: I just need to know are they allowed to (speaking from an unmiked location).

MR. CAMERON: Okay.

MR. FARKAS: I was going to say all of our transmission outages are posted on the Website, all of them.

MR. CAMERON: Frank, do you want to? Did you have an answer? Frank, do you want to repeat that?

MR. KOZA: I was just going to say all of the transmission outages in PJM are posted on the Website. So the answer to your question is yes.

MR. CAMERON: Okay. I guess the question I have for the NRC staff and for FERC is that the generic letter is asking for information, not saying that this is the right information to give us, but is there a need for FERC to consult with the NRC on these emergency day-to-day operation questions at all?

I mean, I don't know. I'm just asking.

MS. COURT: Well, I think that under the memorandum of agreement, that if -- well, let me put it this way. The memorandum of agreement definitely contemplates communication between the two agencies.

Now, these types of questions though we don't deal with on a day-to-day basis. The rules are out there. Every company is required to have a compliance officer. Every company is required to have a compliance plan, and this, you know, has been in effect now for over a year. So a lot of work has been done.

As one gentleman alluded to, his company had a very detailed legal memorandum on it as well. So as far as the NRC and the FERC consulting, that's something that really isn't -- I won't say it's not practical. It's just not going to come up because we don't necessarily have these types of questions come up every day.

But I think that if we did have a question that we needed to answer and we were going to put on 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 are structured, and I'm stating the obvious, but sometimes that's necessary.

I can assure you and I feel very comfortable speaking on behalf of the Chairman of the agency with whom I spoke this morning before I came here that we would work very closely with you on these types of questions.

MR. CAMERON: Okay. That's good. I think you pointed out a couple of different ways where if there was a need, there will be an answer.

Mike Mayfield.

MR. MAYFIELD: I just wanted to point out that I think it's Brian Sheron mentioned this morning the FERC Commission and our Commission are anticipating a joint meeting in the foreseeable future I'm told, and if this is something that is starting to come out as a response to the generic letter, I'm reasonably sure at first at the staff level and potentially at the joint Commission level, this would be something that would be open for discussion.

And if, as Susan suggests, it's not something contemplated by the regulations I'm reasonably sure that the two agencies can figure out how to come to grips with that so that it does get addressed.

MS. COURT: Absolutely, and Chairman Kellaher looks for ward to having that meeting. That was one of the reasons that we were talking about the NRC this morning.

MR. CAMERON: Okay, good. Thank you.

Let's go to Keith and then we'll go to Jennifer.

MR. JURY: Yeah, one last question on that topic, and, Mike, I appreciate the fact that FERC and the NRC are going to work together. I think that where Exelon is and I think a number of other utilities is it appears that the NRC is looking for deeper and more thorough communications than we believe the FERC rules currently allow, and I heard a question put on the table by Mr. Alexander, I believe, and said could FERC review the generic letter and insure that the level of information that's being asked for by the NRC can be shared.

I believe I'd push the "I believe" button on future meetings, but we have a generic letter that's supposed to come out by the end of this month. I think it would serve everybody in this room, particularly the utilities and the NRC, very well if that review could occur in FERC and the NRC could get together and say this is consistent. It's okay that the nuclear plants give this level of information.

And if that's not the case that the NRC revise the generic letter before it's issued to go through the response and the RAI process. It just makes absolute sense that it would get reviewed beforehand and not later on down the road when we're trying to implement this this summer.

MS. COURT: We'd be more than happy to look at it. Again, we have to function within the existing rules, and so to the extent that the information contemplated by the GL is covered by those rules and we can define it, I think we would be more than happy to say that.

I mean, part of the reason that we're here is to be able to provide certain things for the record, and so anyway, I mean, a general -- Demi, do you want to say something?

MR. CAMERON: Let me get you on the record, Demi.

MS. ANAS: I just want to reiterate that there's nothing in the rules that prohibits the nuclear power plant from providing information to the transmission provider. I think that one question implied that. Did I say it -- nothing prohibits the 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 have anything on this at all, David?

MR. NEVIUS: Well, our draft standard -- and Terry can help me here -- does contemplate transmission providers, transmission entities sharing a good bit of information with the nuclear plant operators, coordination of maintenance and planned outages and so on, and a swell as real time operating information.

And I think as Susan said, as long as the nuclear plant operator does not then turn around and share that with their merchant side, there's not a problem.

MR. CAMERON: Okay, and, Terry, do you want to add anything to that?

MR. CRAWLEY: Well, we did think about this --

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

MR. CRAWLEY: -- as we were drafting the standard. Right. R-5 basically says per agreements, per the agreements that the entities would develop, the designated transmission entity, which could be the transmission operator, the reliability coordinator or depending on who the correct entity is, and the nuclear plant shall coordinate planned outages and maintenance activities affecting the nuclear plant interface requirements.

So the concern is the impact that these activities could have on the plant and on their ability to meet their licensing requirements for safe shutdown and, you know, having adequate off-site power.

So in fact, we were discussing that maybe we had some discussion about adding something into the standard to actually strengthen the requirement to address any standards of conduct requirements and make sure that there are no problem -- basically grease the skids -- make sure there's no problem. You know, discuss these things up front and make sure there are no problems up front.

Now, if the standard is not out yet and we're already having these concerns, so it's kind of after the fact, but let me say one thing. I work on the nuclear plant side, okay, and I think this communication is very important that it take place, okay, for the safety of these plants, but after what I've heard here, if I were the transmission operator or reliability coordinator, I've got a FERC rule that I don't want to violate. I don't have anything from the nuclear side right now that tells me what I can and cannot do. I'm going to land on the conservative side and make sure I don't violate the FERC rule so that I can understand why a communication may not take place in this environment today.

So that's all I'm going to say and shut up and sit down.

MR. CAMERON: Thank you, Terry.

MS. COURT: Okay. One thing, and I think what you're hearing from the FERC representatives here is that we're a little incredulous, I guess, because we thought that the rule provided the type of communication and was an impediment to the type of communication necessary to enable the nuclear facility to get off-site power.

So you know, if that were the case, I mean, that would not be as contemplated by the rule, and I think what we're going to need is some really specific examples of this, as why that would be a problem.

Generally, we will look at the draft GL. I'm not sure if the draft GL has the specifics in there that is going to basically give you all the comfort that you want, you know, just reviewing it very quickly without looking at it for the specific thing.

I didn't see how -- nothing triggered

necessarily a concern vis-a-vis the FERC's rules. So there's something going on here or there's something -- there's an undercurrent here which is kind of a mystery to me because, again, knowing what the purpose of the rule is and what the exceptions are intended to accomplish.

So there's maybe just some more communication that is needed in that regard. I am not comfortable with promising that the FERC, the Commission, you know, in a quorum voting will comment on the generic letter. I don't think that is really appropriate, and rarely, rarely, in 24 years at the FERC have I seen the FERC itself as the Commission weigh in on another agency's rulemaking or the equivalent of a rulemaking. I may be able to give you some informal staff comments on it.

MR. JENKINS: One other aspect of this, and I guess this is what my boss is getting up to say is that Brian Sheron this morning mentioned that we will be pursuing a temporary instruction for the summer of 2006. I wish we didn't have to do that, but we need to have assurances for this next period, and the generic letter getting out and getting the information back, especially having this kind of a dialogue, will give us information we can use to make a smarter temporary instruction type of an assessment.

So I don't know if I hit the mark there. Did I?

MR. MAYFIELD: Well, I guess I was going to say two things. One, Susan, first of all we would very much appreciate any comment now or before or after the generic letter goes out just to make sure we're all sort of on the same page.

MS. COURT: Absolutely.

MR. MAYFIELD: Once the generic letter is out, if you're having trouble responding the questions because you somehow feel there is a legal prohibition to the TSO providing you information, that would be a really good answer to put in the generic letter telling us we need to not do anything because you might not be able to answer the question just as a nonstarter.

So if that prohibition exists, your legal departments believe it exists, that would be a really good answer, and I think as Chip said, that would join the issue between the two commissions, but to set and continue to wring our hands with hypotheticals, we need some specifics to deal with, and then I'm sure the two Commission will sit down and make this thing come out in the right place.

But this issue isn't something that I see as in the best interest of the Nuclear Regulatory Commission to not move forward with. If it's a real issue, then it's something where we need some clarification between the two Commissions to make sure you're able to get the kind of information you need to assure the safety of your plans.

MS. COURT: Thank you.

MR. CAMERON: Okay. Thanks, Mike.

And this is an important issue obviously, and there's a few jagged edges here, and I think that part of Susan being perplexed is because of the fact that people are reading implications into the generic letter rather than just tell us what procedures you have in place.

They're thinking that there's another shoe that's going to be falling there, and I think the staff is probably going to wait for that other shoe to fall, and they want to see what information comes in.

But as Mike pointed out a legitimate answer may be that while we don't have this type of procedure because we don't think that we're allowed to get it from --

MS. COURT: You know, I think the thing that's perplexing, too, and Demi has been living and breathing and drinking these rules for many years, I mentioned the comment that the Commission itself and the exception that the Commission itself made in response to one of the commenters in the rulemaking proceeding.

But, Demi, correct me if I'm wrong. Has this been a problem? This is like news?

MS. ANAS: This is actually one aspect of the rule that we thought didn't change. We had hundreds and hundreds of comments and opinions during the rulemaking proceeding over a three and a half year span. Only one person brought it up.

You know, we can only, as Susan said, we can only articulate what the Commission has already said, and everybody had the opportunity to participate in that rulemaking proceeding. So the Commission addressed the comment that they had received.

I think had people fleshed it out more during the rulemaking proceeding, we might be able to tell you a little bit more now because the Commission would have spoken on it. So, you know --

MS. COURT: But even then, Demi, have we gotten even questions from the nuclear industry?

MS. ANAS: I got one, I think, over the summer.

MS. COURT: Okay. So that said, let me just assure you that just because the Commission hasn't spoken to it specifically because only one or two people have raised it in all of that time, that we are -- let me put it positively -- we are open minded about this and we want to hear if there are any problems and if there are any impediments.

And I reiterate that the two agencies will work closely together to insure they are not. We're not going to necessarily -- and I'm sure that the NRC wouldn't want this generic letter proceeding to be used to circumvent a set of commercial regulations. I'm sure they wouldn't want to do something like that.

MR. CAMERON: I think we can say we wouldn't.

MS. COURT: I think it's safe to say, too, but we're talking about operations here. We're talking about reliability here, and I think we're all on the same page as far as making sure that both the grid and the plants are absolutely reliable on behalf of this country. I mean there's no question about that. Everybody in this room, everybody at both agencies, we all have the same goal. So we'll work together.

MR. CAMERON: Okay. Thank you, Susan.

We're going to go to Frank and then Jennifer, and I think we're going to close off for today. We're going to come back tomorrow, and tomorrow is basically going to be reprise of a lot of these issues because we're going to hear from the industry possibly on a lot of the same issues, and then we have an open session.

So we're running about 15 minutes behind time. So we want to try to get you out in time.

Frank and then we'll go to Jennifer.

MR. KOZA: Thanks, Chip.

I just want to amplify Susan's points. Our interpretation is there are no impediments to sharing information with nuclear power plants. When the issue is nuclear safety, we will share anything with the nuclear power plants, and I don't think there are any -- I have to agree with it. I don't think there are any impediments to sharing information.

Now, there are impediments on the commercial side with the further dissemination of some of that stuff, but regarding communication with nuclear power plants, there's nothing we wouldn't share in a nuclear safety environment.

MR. CAMERON: Okay. Great. Thank you, Frank.

And Jennifer.

MS. WEBER: Jennifer Weber, TVA Operations.

This is a question mostly for FERC, although NERC may have a point. This is about undue preference. What is FERC's position on providing preferential service to a class of generation?

Because generally speaking nuclear plants require higher voltage requirements than anyone else that uses the grid, and usually the consequences of not being able to meet that is a controlled, orderly shutdown of a unit which would not impact bulk system reliability.

MS. COURT: Let me just give you the classic legal answer from both the PAR Act and the GAS Act.

Both acts, PAR Act here is the relevant one, prohibit undue preference, undue discrimination. Unlike some other statutes that forbid discrimination, our statute forbids undue discrimination. So their justified discrimination is permissible under the federal PAR Act, and so you know, if there is a reasonable justification for discriminating in favor of one class of customers over another class of customers, over one customer versus another one, the

Commission has spoken to how competition and meeting competition could be a justification for discrimination.

Contracting by itself is discriminatory. In other words, the PAR Act is based on contract carriage, and so is the GAS Act. Entering into a contract actually is a form of discrimination because you're locking in a certain amount of capacity or you're locking something in.

So the statute in our regulations, accordingly, do not prohibit preference for one group. If the preference is justified, it is not undue, and that's decided on a case-by-case basis.

MR. CAMERON: Okay. Thank you.

We've had a request from some people who may not be here tomorrow to just briefly try to address this issue which came up before, the issue being one that Frank Koza also put up for us.

So let's take a few more minutes and talk to this and then we'll adjourn.

What level of additional notification or discussion should there be? And, you know, Frank is basically saying that there's going to be protocols on notification, level of trust and notifications will occur, and Ronaldo, well, someone responds to the generic letter with that. You know, that's a response.

MR. JENKINS: If I was the licensee in the PJM system and I said, okay, describe -- I was responding to this question -- describe the procedures to periodically check with the TSO to determine the grid conditions, et cetera.

I would then go back to the PJM procedures. I would refer to those as the basis in which I run my plant and here's processed that we follow and the notifications that we have committed to. That would the answer.

MR. CAMERON: Okay. So you've heard Ronaldo's take on that. Let's -- I'm going to Mr. Thorson a minute. Let me go to you to see, John, what you think of that.

MR. GRANGER: This is John Granger, FPO.

Well, the real question is are you requiring the nuclear power plant operators to contact the TSO on a regular basis to, you know, determine the status of the grid. Is that going to be a requirement?

MR. JENKINS: The GL doesn't contain any requirements. If you're saying whether the staff has a preference one way or the other, I don't think that the higher goal, if I can use that term, is that we are interested in making sure that nuclear power plants are working with the transmission system operators to insure reliable off-site power, and we're not trying to prescribe any particular limits or numbers or anything of that nature.

Obviously if something is working and it's working well, then we will not have a problem with it. It's only when there's an indication that this might create a problem that staff might come back and ask an additional question.

And so that's pretty much -- does that answer your question?

MR. CAMERON: John, this runs through this whole GL, is that people are reading requirements into it. How would that question -- how would that read that would alleviate your concern that there's a requirement?

MR. GRANGER: Well, it simply says describe the procedures, you know, that you use to check the TSO periodically. To me that's saying if you don't have procedures that require you to check with the TSO, then that's not a desired, okay, condition.

So it seems like it could be reworded such that, you know, if there was an agreement in place between the TSO and the NPP and it was working and you were notified if there was a condition of instability or degradable, then that would be acceptable, period.

It's not like there is an onus that we have to contact the TSO on any periodic basis, you know, unless there's a problem.

MR. CAMERON: Okay, and I think I see some agreement with you on this and perhaps the staff needs to think about, even though it's not intending anything, maybe there's a way to reduce the anxiety of the way these questions are asked.

And let's go to Mike Mayfield.

MR. MAYFIELD: Two points. First, Frank, I think in your presentation you said you'd like to not create communication centers to deal with this. As much as I might like to own stock in the telecommunications world, I don't. So, no, we're not looking to create communications centers.

I did commit this morning to Mr. Rosenblum that we would go back and look at was it 1(a) versus 1(d), whatever those two questions are. We'll go back and look at it and try to make clear on this issue.

You know, I don't know what more we can do today. We appreciate the sentiment. We understand the concern, and we'll go back and try and make sure we're clear on what we're trying to do with these two questions.

MR. CAMERON: Great, and you heard Mike make that commitment, and I guess I would just ask you in preparation for tomorrow, did the types of things you heard today from the NRC staff, including going back to look at some of these issues, is that getting to some of the concerns that you have with the generic letter?

Because we want to make sure that we're making some progress here.

And I just would leave you with that because I think we need to adjourn at this point and take up tomorrow at 8:30. It's going to be a reprise of the day today, perhaps more focused, and so I'd just ask you to think about those questions.

If you're not going to be here tomorrow, if you have a concern, a question, please use one of the comment cards and fill it out, and we will put that into the mix.

Correct, Ronaldo?

MR. JENKINS: Correct.

MR. CAMERON: And I just have to ask you to give this final panel and also will include the previous panel in that round of applause for --

(Applause.)

MR. CAMERON: And thank all of you. I'm sorry that we didn't get to everybody today, but we will get it in the mix tomorrow.

(Whereupon, at 4:19 p.m., the meeting was adjourned, to reconvene at 8:30 a.m., Tuesday, January 10, 2005.)