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BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

- - - - - x
IN THE MATTER OF: :
ELECTRIC SYSTEM INVESTIGATION TEAM :
RELIABILITY RECOMMENDATION CONSULTATION :
- - - - - x

Marriott Philadelphia Downtown
1201 Market Street Salon G
Philadelphia, PA

Tuesday, December 16, 2003

The above-entitled matter came on for technical
workshop, pursuant to notice, at 8:00 a.m.

1 APPEARANCES :

2 TOM RUSNOV, Canada

3 DAVID MEYER, DOE

4 ALISON SILVERSTEIN, FERC

5 DAVE HILT, NERC

6 DON BENJAMIN, NERC

7 MIKE KORMOS, PJM

8 MARK FIDRYCH, WAPA

9 LINDA CAMPBELL, FRCC

10 MICHAEL CALIMARIO, NYISO

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P R O C E E D I N G S

8:00 a.m.

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3 MR. CAULEY: My name is Gerry Cauley. I work
4 with NERC and I will be facilitating the meeting but most of
5 the actual work will be done by other show will be speaking
6 and presenting.

7 I'd like to start off first of all mentioning
8 that this technical conference is sponsored by the U.S.-
9 Canada task force on the August 14 blackout and representing
10 that task force today is David Meyer of the Department of
11 Energy and he' going to open the conference with a few
12 remarks from the Task Force.

13 MR. MEYER: Good morning ladies and gentlemen.
14 Welcome on behalf of the Task Force. As I am sure you have
15 all had some opportunity to take at least a quick look at
16 our interim report that we issued in November and while
17 we're interested in your comments on the report, the primary
18 purpose of this meeting is to obtain your ideas on
19 recommendations going forward. That is, recommendations
20 pertaining to policy or to institutional changes,
21 organizational changes, operational changes that are needed,
22 recommendations of all kinds pertaining to improving to
23 reliability of the nation's electricity grids now and the
24 North American electricity grids.

25 So at the meeting today is formatted to

1 facilitate discussion, that is, the panelists will frame
2 issues and put questions on the table and then once those
3 questions are on the table then we will open it to
4 discussion and get your ideas.

5 But in the event that, well, it's frequent, given
6 the complexity of these questions, I think it likely that
7 there will be issues that can be still aired further
8 fruitfully or maybe after you leave the room, leave this
9 meeting, you will get additional ideas that you think are
10 relevant.

11 So I want to encourage you to make full use of
12 the websites that we have available, the mailboxes, the
13 electronic mailboxes that have been set up. There's one
14 mentioned here in the agenda I see there is one for the
15 United States and one for Canada where you can file comments
16 and any of those comments will then be transferred to the
17 DOE website and naturally we will see whether the Canadians
18 have done similar things.

19 At any rate any comments that we receive will be
20 put on DOE's website so that you can access that website and
21 see the full record of commentary that has been provided and
22 then you can offer additional comments or you can respond to
23 other comments or whatever you would like.

24 But it is a great opportunity to get a very full
25 discussion of these issues so I encourage you to make good

1 use of that.

2 With that, Gerry, let me see -- we have Tom
3 Rusnor here also.

4 MR. RUSNOR: Good morning ladies and gentlemen.
5 I'd just like to inform you that we're planning a technical
6 conference for Toronto on January 9. The intention is that
7 will be complimentary to this conference and hopefully will
8 not be duplicative and also to give enough opportunity for
9 those who could not attend today to come and make their
10 views known and to exchange ideas. So if you or your
11 colleagues would like to attend we'd be pleased to welcome
12 you. It will probably be held at the Westin Harbor Castle
13 Hotel in Toronto and that would be January 9.

14 Following this session we will craft an agenda
15 that as I said hopefully will compliment this session.
16 Thank you.

17 MR. CAULEY: Alison Silverstein who is also one
18 of the co-chairs of the electricity working group will be
19 here later today. She had a conflict first thing this
20 morning. She will have Alison and David and Tom as the
21 three co-chairs of the electricity working group of the U.S.
22 - Canada task force.

23 Supporting them in the investigation and the
24 analysis is a technical team based out of Princeton and Dave
25 Hilt, director of compliance and NERC has been the leader of

1 that investigation team and he's going to open with a few
2 comments and I think you can probably do it from there Dave.

3 MR. HILT: Thank you and welcome. I'm very happy
4 to see a very good turnout, I think, today for the technical
5 conference. We've spent quite a bit of time obviously
6 looking at this event as I've talked to a number of people
7 this was needless to say a very, very large scale event.
8 There were thousands and thousands of discrete events to
9 take a look at in terms of evaluating this blackout. It was
10 a very, very large challenge.

11 I just thought I'd start off by putting up some
12 of the statistics. Many of these are out of the report so
13 they are available. But certainly it was reported to have
14 affected on the order of 50 million people. We know that
15 there was between 60 and 65,000 megawatts of load initially
16 interrupted as a result of this blackout that represents
17 approximately 11 percent of the entire Eastern
18 interconnection which is a very large interconnection. It
19 is the largest -- 531 at least generators that we've
20 identified that tripped 261 different generating plants.

21 So that's very, very large numbers of control
22 systems, systems that operated during this event that we're
23 certainly wanting to take a look at, look at recommendations
24 for from the time that the Sama Star line tripped at
25 approximately 4:06 p.m. the blackout was essentially

1 complete by 4:13 p.m. That gives you the time frames of
2 how quickly some things happened here.

3 So there's a lot of technical areas to be looked
4 at in just that very short period of time as to how systems
5 responded et cetera. The actual high speed cascading of the
6 system when it really ramped up, it began to ramp up of
7 course after the Sama Star line trip and then following that
8 it ramped up even quicker as things progress through
9 Michigan and ultimately on around into New York.

10 But the high speed cascading was about a 12
11 second time frame. So that's very fast. And as I said
12 thousands of discrete events and we spent just a huge amount
13 of time. I know that the folks that were working on the
14 sequence of events trying to coordinate and identify the
15 actual sequence and looking at the time stamping that that
16 was a very, very large job to sort all of that out.

17 Go ahead Gerry.

18 (Slide.)

19 This was how we had organized it. Many of you
20 have seen this and I won't go into it but we had actually
21 broken the task up into areas of technical expertise where
22 we could bring experts in from various disciplines including
23 generation, transmission, system planning and design -- all
24 the various key areas that we have industry experts in the
25 field, a number of them came in, their time was volunteered

1 so we had a whole host of volunteers from all over North
2 America including the U.S. and Canada participating in all
3 of these various teams that dug into the black out.

4 Go ahead Gerry.

5 (Slide.)

6 NERC early on issued some near term actions and
7 some of these things we expect to see some further
8 recommendations on all of these going forward. These were
9 some things that we identified earlier and I'll go into how
10 we got to some of those but certainly voltage and reactive
11 management is a key issue insuring that there's adequate
12 voltage support -- we hope to hear some more about those
13 things as we go forward and whether there's recommendations
14 needed for those.

15 Communications, reliability communications,
16 certainly we need -- we believed and our board believed that
17 there needed to be some work done to strengthen and
18 implement communications protocols between all of these
19 operating entities. Failures of system monitoring and
20 control functions and systems, certainly we saw some of that
21 and we felt that there needs to be some discussion about
22 what kind of recommendations we may need in those areas.

23 Go ahead Gerry.

24 (Slide.)

25 Emergency action plans, what plans do we have in

1 place to take action when there are system emergencies and
2 what areas do we need to address there? Training for
3 operators, training for emergencies, training for
4 communications et cetera, conducting emergency drills was an
5 area that the NERC board felt needed to be addressed.

6 And finally vegetation management, looking at our
7 rights of way to make sure that they're clear of
8 obstructions, et cetera.

9 Those were the six areas that the NERC board felt
10 at their meeting in October were fairly important that we
11 needed to get out early and say we could take a look at.

12 One of the things that I found interesting was
13 that I went back and we looked at some of the past, you
14 know, the earlier, blackouts and I thought I'd just give you
15 some of the highlights from some of those.

16 These are some words out of the November 1965 New
17 York blackout, some of the recommendations that came out of
18 that and I won't go through all of these but basically
19 you're going to see that we need the first one is related to
20 tools -- the operator having displays and equipment to
21 monitor the system adequately.

22 In the '65 blackout there was a recommendation
23 for coordinated programs of automatic load shedding that
24 needed to be established and maintained.

25 Finally thorough programs and schedules for

1 operator training and retraining need to be rigorously
2 administered and those were some pretty good words that came
3 out of '65.

4 Go ahead Gerry.

5 (Slide.)

6 In '77 we had another blackout in New York. It
7 was noted that the single most important cause of the July
8 '88 power failure was the failure of the system operator to
9 take the necessary action. Again -- emergency preparedness
10 and training came into that area. From that make a thorough
11 re-evaluation of the selection and training of system
12 operators so we've heard training now in at least two of
13 these blackouts and a fullscale simulator should be
14 available to provide the operator personnel with hands-on
15 experience.

16 So we're looking again at the operators tools
17 that were available before them and the training.

18 Go ahead Gerry.

19 (Slide.)

20 July 2 '96, again reviews the need for security
21 monitor function to monitor operating conditions on a
22 regional scale and promote interconnected system
23 reliability. Somebody who has the tools to monitor the
24 system in a wide area to determine what's going on, review
25 the need for tools such as on-line power pull and stability

1 program in real time.

2 Again we're talking about things that we're
3 providing to the operators out there to do their job.

4 And finally review the process for assessing
5 potential voltage instability and the need to enhance
6 existing operator training programs and tools.

7 So again we've got a lot of the same themes I see
8 in some of these. These aren't all of the recommendations
9 that I'm obviously just pulling some of them out. Go ahead.

10 (Slide.)

11 August 10 '96, again development periodic review
12 of reactive margin -- that's something that we've heard some
13 things about here -- coordination among regional members
14 with neighbors and with their neighboring systems. Again
15 communications, developing communications systems and
16 displays that give operators immediate information on
17 changes in the status of major components on neighboring
18 systems, again monitoring tools to be able to see what's
19 going on, strongly encourage operators to exercise their
20 authority and finally train operators again so we're seeing
21 a lot of the same themes in at least in some of these areas
22 pop up in many of the blackouts.

23 Go ahead Gerry.

24 (Slide.)

25 Today you're going to have some panelists that

1 were involved with the blackout investigation that are here
2 to listen to hear some of your recommendations regarding
3 moving forward and I'm going to highlight the key areas that
4 I think we have selected, some of the panelists from.

5 Certainly this operation tools, SCADA/EMS
6 communications and operations planning -- this really covers
7 the gamut of operations and you're going to have folks here
8 from those -- from that panel or from that investigation
9 team who can and are here to hear your recommendations and
10 see what we may need to do going forward to prevent future
11 blackouts in that area.

12 And Gerry?

13 (Slide.)

14 System modeling and simulation analysis and
15 system planning and design. There's been a huge effort
16 underway to build computer models and model what happened on
17 August 14. Much of that has been done up through all of the
18 what we would call "steady state modeling" the load flow
19 modeling. The teams are in to the dynamic modeling looking
20 at the dynamics phase of this. That's a huge effort.

21 There was a very large dynamic event a number of
22 events actually where the system broke apart, reclosed back
23 together, so it's going to take some serious time to
24 complete that analysis.

25 But they're also here, particularly the system

1 planning and design team with regard to looking at voltage
2 reactive management, some of the issues that you saw there.
3 They will be here as well to look for your recommendations.

4 Okay Gerry.

5 (Slide.)

6 Transmission system performance, protection and
7 controls -- although we did not see significant missed
8 operations of system protection, we're also looking for what
9 do we need to do in terms of the transmission system from a
10 technical standpoint to help us protect it from blackouts.
11 Also generation performance protection and controls -- as
12 you saw earlier there were many, many generators that
13 tripped during this event, some were, they tripped for a
14 variety of reasons, everything from over excitation to just
15 basically loss of the load on the generator. So we saw
16 many, many different trips, over frequency, under frequency,
17 just about every kind of operation that you can identify was
18 in this -- blackout.

19 So we need to take a look at what we need to do
20 with generation systems, their performance, their
21 protection, their controls, and so we're looking for any
22 recommendations that the industry may have on these two
23 areas.

24 Go ahead Gerry.

25 (Slide.)

1 So what we're trying to do here is not so much as
2 David Meyer noted we are interested in comments on the
3 report hopefully on the interim report or the DOE certainly
4 is, I know the U.S. - Canada task force is, but what we're
5 trying to do here today is we're trying to look forward and
6 say what do we need to do now that we have this information
7 in front of us of what happened on August 14 -- what do we
8 need to do now to prevent these future blackouts? What
9 types of new standards, procedures and protocols may be
10 necessary?

11 What existing technologies? There's a lot of
12 existing technology out there for things that could
13 potentially be applied to the system that may not have been
14 that should be considered, what new technology should be
15 considered for implementation in the industry to prevent
16 these types of blackouts from occurring in the future, what
17 types of changes in system planning and design assessment do
18 we need to be doing in the industry as a whole and changes
19 to operate, to operator tools and training programs, what
20 kinds of things are there -- just some of the areas that
21 we're looking for input on and we're open to looking at any
22 other areas that I may not have included on this slide.

23 The key to it though as I went back through the
24 previous blackouts is it has to be implemented. And I think
25 we're going, as an industry, I personally think we're going

1 to need some monitoring mechanisms in place for whatever
2 recommendations the industry comes forth with to present, to
3 prevent these types of blackouts that there'll need to be
4 some monitoring mechanisms in place to monitor that progress
5 of implementation to assure that we really do implement the
6 recommendations and follow through on what we need to do.

7 Go ahead Gerry.

8 (Slide.)

9 Standards, which is certainly NERC's area and
10 we're very interested in that. Presently we have operating
11 policies and planning standards. Today we have a new
12 standards process in place in developing reliability
13 standards. It's an open process. All interested parties
14 can vote on it, can participate in the ballot bodies, so I'm
15 going to make a plug here for everyone that's involved in
16 looking forward in solving solutions, in finding solutions
17 to the blackout that we need to be involved in the new
18 process and make sure that we're working to get appropriate
19 standards in place if they're not in place.

20 Looking at what standards need to be developed,
21 we are going to continue to look at other violations of
22 standards that may have occurred during the blackout and
23 what areas that need to be addressed through new and
24 improved standards.

25 I think there's one more Gerry.

1 (Slide.)

2 As we noted, as I am sure everyone in this room
3 has read the interim report, it's available on both the DOE
4 and the U.S. - Canada task force sites as well as at NERC.
5 We're in the process now of working with the U.S. - Canada
6 task force in developing the final report on NERC's role.
7 Our role remains involved with the technical evaluation, the
8 technical investigation, of what happened and why things
9 happened. NERC may well also submit recommendations into
10 the process but today the entire task force is looking for
11 recommendations particularly related to the technical area
12 as we move forward -- how do we solve this and we're seeking
13 that input today.

14 So with that, Gerry, I think I'm finished.

15 I look forward to the discussions today and we
16 will, may be, asking the other panelists up here questions
17 as well. Thank you.

18 MR. CAULEY: Okay, Dave did a good job of
19 introducing the conference and what we're here about today.
20 Thanks a lot.

21 Essentially if you go back and look at the report
22 that was issued on November 19, the report is very factually
23 based and narrowly focuses I think on the direct and
24 immediate causes of the blackout and tries to explain that
25 in a lay person language that is easily understood by the

1 public, by policy makers in Washington, in Ottawa and
2 elsewhere, and just generally anyone who had an interest or
3 was impacted by the blackout.

4 Because the report was so simply stated, so
5 simply and directly stated, doesn't mean that there was not
6 a lot of technical detailed analysis behind it and I assure
7 you there was and I think we are fortunate today that we
8 have a number of the team leaders here who will be able to
9 speak on various panels and go into a bit more detail about
10 the analysis and where potentially it can lead in terms of
11 developing a final set of lessons learned and
12 recommendations.

13 So that's where we're headed in this next phase.
14 There are a lot of people I think on the U.S. - Canada task
15 force as well as the technical investigation teams
16 supporting them, to really figure out what went wrong and to
17 make sure this doesn't happen again, at least in our time
18 on our watch, that something like this doesn't happen again.

19 So you can point to some very direct and
20 immediate causes if you go back and reconstruct the time
21 line and what happened, who said what to whom on August 14?
22 What we're about now is what went on behind the scenes to
23 allow that to happen? Why did that happen? Why was it
24 allowed to happen?

25 It gets into issues of are the standards

1 adequate? Are the standards being enforced? Are we
2 studying the right thing on the system, both regionally,
3 nationally, gridwise and locally?

4 Do we have voltage problems or do we not have
5 voltage problems? We can point at one level to exactly what
6 happened but you look underneath that there's a whole set of
7 issues that arise that we need to deal with and we're hoping
8 to deal with that in the next month to two months as we
9 develop the final report and a set of recommendations.

10 The inputs from this group today are very
11 important. This conference is being transcribed and I
12 assure you that all your comments will be directly reviewed
13 by the team leaders as well as the U.S. - Canada task force
14 and your comments are important in formulating the lessons
15 and recommendations learned in the final report.

16 We have five panels set up in five technical
17 areas, the first being reliability coordination. Obviously
18 we may have thought beforehand that we had a good view of
19 the system and good coordination of reliability among
20 reliability coordinators and with operating systems and
21 control areas. The events of August 14 point to a
22 substantial breakdown in those assumptions in terms of what
23 was actually happening.

24 So we have a panel, the first panel up here, A,
25 will deal with some of the reliability coordination issues.

1 Then we move to a panel on emergency response,
2 the ability of operating personnel and reliability
3 coordinators to recognize emergencies, act decisively, have
4 the authority to take action when needed to prevent
5 catastrophic failure of the grid.

6 The incidents on August 14 point to shortcomings
7 in the area of operator tools, our ability to see the big
8 picture, our ability to understand what's going on in the
9 system, many of these things Dave Hilt pointed out were
10 learned in prior blackouts and we need to ask ourselves --
11 why are these tools that should be available not available
12 and being used -- and what new tools and technologies would
13 help us provide a better set of information for the
14 operators and reliability coordinators.

15 Panel D, we're looking at system analysis and
16 study. There's been a lot of conjecture about what actually
17 happened in the blackout, what caused it? Was it a voltage
18 collages, was it not? We'll have some input from the team
19 leads and some panelists to talk about those issues.

20 I think more importantly there are two aspects of
21 panel D, there were some very interesting phenomena that
22 occurred during the actual cascade. We did eventually as
23 the cascade progressed get into frequency collapse and
24 voltage collapse and significant power swings and those
25 kinds of things. The question is, if we do have a major

1 disturbance on the system in the future, how can we keep it
2 from propagating throughout the rest of the system?

3 So how can we design the system better, operate
4 it better, so that we don't allow that kind of system to rip
5 apart and collapse as it did in this case?

6 And finally panel E we're looking at protections
7 and controls, transmission protection, both the mundane
8 protection we have for lines and transformers and so on but
9 also more advanced types of schemes that might help protect
10 the system and limit the propagation of cascading outages,
11 as well as generation protection -- did the generators
12 participate as they should have? Is there a way we can
13 improve generation response during severe perturbed system
14 conditions, and can we more effectively coordinate
15 transmission and generation protection as well as load
16 reduction schemes that might be possible?

17 So that's what we're going to try to do today.

18 Next slide.

19 (Slide.)

20 In terms of format, we first off I want to
21 express my appreciation not only for this panel but for all
22 five panels, the folks that volunteered, some volunteered
23 more than others, but they're all here, so we thank them.

24 We appreciate their taking the time to put some
25 thought into a set of recommendations in their perspective

1 of what needs to be done to operate the system better in the
2 future.

3 Each panel will speak one at a time. We'll go
4 down the row as we see them here. We also have a team lead
5 speak to that set of issues, in this case it will be Don
6 Benjamin from the NERC staff -- once the speakers have made
7 their short presentations the panel will be subject to
8 questions from the investigation team and then also we will
9 open it up to the audience.

10 And I encourage you, if you made all the effort
11 to get here, I encourage you to step up to the mike, ask
12 your questions, make comments, because it's not just the
13 formal presentations it's the comments from the audience
14 that will make the difference in formulating the
15 recommendations. We're still very early in the stages of
16 developing recommendations, do not have a "road map" do not
17 have a set of plans in terms of what those recommendations
18 are. Please, you're here, let's hear your inputs, and get
19 those ideas for what those recommendations should be.

20 Just a couple rules and I will enforce these
21 lightly, unobtrusively but when I do if I need to I will.
22 First off, we're not going to get into any business, anti-
23 trust issues, discussions of market pricing or anything like
24 that, just basic anti-trust stuff. I'm not a lawyer but I
25 can smell it if I hear it.

1 We're going to focus on broad technical issues of
2 relevance to the industry. We're not here to correct the
3 behavior of any one entity or party or point out the
4 shortcomings of individual parties' report of November 19
5 says what it says. We're not here to prove or disprove
6 that. It stands on its own.

7 If you have comments on the validity of that or
8 any other facts you'd like to present to the task force, I
9 encourage you to submit that in writing.

10 Today is about what we can do as an industry to
11 operate the system better in terms of all these technical
12 aspects and we'd like to be proactive, constructive -- what
13 can we do better?

14 Next slide.

15 (Slide.)

16 There is a one-way audio feed so even though we
17 have a good number of folks in the room, there are many
18 more, I suspect hundreds, listening in on an audio webcast
19 available from a link from the NERC website and we
20 appreciate those folks listening in.

21 Unfortunately we didn't get high tech enough to
22 allow them to interact and submit questions but they can
23 listen in to the discussions and they can submit written
24 comments to the Task Force after the conference.

25 There is a transcriber as I mentioned in the back

1 and we will publish a set of transcribed notes from the
2 meeting and I encourage you to submit written comments.
3 There are two places you can do that, one representing
4 Canada and one representing the U.S. and my understanding is
5 it's a shared pool of comments and both the U.S> and Canada
6 will share those comments so it's really up to you which is
7 more convenient as to where you post your comments.

8 And for those of you familiar with NERC meetings,
9 this meeting is sponsored, technically is hosted by FERC and
10 I think we found somebody who provides less food and
11 refreshments at a meeting than NERC. Because today we will
12 have coffee at the morning break and the afternoon break but
13 lunch will be on your own and we'll try to give you
14 sufficient time. There are several restaurants in the hotel
15 or just outside so we'll -- unfortunately we can't service
16 that today but we'll give you sufficient time to get in and
17 out and come back for the afternoon session.

18 That is it, I think that's my last slide -- okay,
19 with that we will start and go ahead with the panel.

20 Any administrative or logistical questions before
21 we go, before starting with the first panel? Okay, good.

22 We'll start off with the first panel. This one
23 is focused on reliability coordination, a function that was
24 sponsored by NERC and initiated recently in the last few
25 years particularly after the '96 blackout and we'll start

1 with Michael Calimano from the New York ISO. You can speak
2 from there or here. It's your choice.

3 MR. CALIMANO: I'll speak from here. I guess when
4 we saw the list of questions and the time frame on it it is
5 a quick overview of what I saw going on and a couple of
6 points that I wanted to see going forward on it.

7 For what lessons learned on it -- Gerry, next
8 slide --

9 (Slide)

10 -- it really focuses on a reliability coordinator
11 for us to see a wide area within a coordination area. A
12 reliability coordinator needs to see enough of it not
13 necessarily flow gates for scheduling purposes but it has to
14 see how the system operates. Let's understand that.

15 We can do that with various bits of data. A lot
16 of this stuff already exists in some form or another, but it
17 puts another set of eyes on real-time operation of the
18 system.

19 The other point I wanted to point out was the RC
20 with the control area and I guess we're kind of different at
21 least in New York where we have transmission operators who
22 monitor transmission within their local control -- local
23 areas. The New York ISO monitors the entire state on a volt
24 power system and the ability to look into individual
25 transmission systems.

1 But they've got to be capable of monitoring each
2 other and backing up each other. Case in point -- I thank
3 Gerry for showing the '65 blackout and the '77 blackout in
4 New York -- clearly there were a lot of lessons learned from
5 those two. One is the understanding especially in '77
6 somebody understanding from another, from a broad
7 perspective, what's going on when you may not have all the
8 information. And this is what happens most times in
9 blackout situations.

10 The operators don't have all the information and
11 have to rely on somebody else to let them know what's going
12 on and take direction from each other.

13 Next slide?

14 (Slide.)

15 Reliability coordination needs to have authority
16 in real time to order actions to be taken by control areas
17 or operators under emergency conditions. It has to be
18 spelled out well beforehand. You can't get into a
19 discussion at the time and it can't be a request.

20 It's an order and an order takes action and you
21 call up and follow up afterwards with any discussions on it,
22 was it the right order or not, but clearly in a real time
23 situation, action has to be taken, has to be spelled out,
24 and noted. This has to be worked out well before the
25 emergency, people have to understand who's in charge and

1 when, and what actions they can do and cannot do on it.

2 I think efficient communication with surrounding
3 control areas, reliability coordinators, we have methods of
4 doing that. They're slow, they're inefficient -- they're
5 good if you're into a capacity shortage as you are planning
6 for a few hours ahead and you can alert the world to that.

7 In real time it's difficult and it's difficult
8 because in real time they're up to their eyeballs trying to
9 solve the problem.

10 We have to look at how we can do this better, how
11 we can let other people know better and faster and in our
12 shop, when there is an emergency going, everybody's involved
13 and to solve the emergency and the communication comes
14 later.

15 I think we got to work as a group to be able to
16 effectively do the communication why we're in the emergency
17 and so we get the word out as quickly as possible on it. I
18 think that's indicative of everybody's situation.

19 One of the questions was should we share between
20 reliability coordination -- and share redundancy? I keep
21 coming back to the clear lines of communication and clear
22 lines of authority -- it's necessary to know who, point by
23 point, is going to take actions under what conditions and
24 who's going to make a request for changes and who's going to
25 make an order for changes.

1 That procedure, that protocol, has to be worked
2 out well before that so people know what page they're on
3 when they're talking with each other on it. If a
4 reliability coordinator declares an emergency, whatever
5 criteria one uses to declare emergencies -- we have a major
6 emergency terminology in New York.

7 But once he declares it then it becomes command
8 and control right away and action is taken. What I'm
9 looking for is that ability spelled out across the board as
10 whatever the term for emergency from your reliability
11 coordinator, that those actions that now define that now we
12 are in this emergency condition, these are the things that
13 you will follow on with an order to either redispatch, take
14 voltage reductions, load shedding, what have you -- they
15 become orders, orders have to be followed, can be discussed
16 later but they have to be followed at the time the order is
17 given.

18 I think monitoring the critical facilities of
19 neighboring control areas, this is an area that I constantly
20 get asked about myself, how far into PJM, how far into
21 Ontario, how far into ECAR do we see -- and is it important
22 and will it give me an early warning system?

23 I think some of the things came out was that
24 maybe we should monitor the Lake Erie loop in different
25 locations on it. I believe there's sufficient data out

1 there and on the network and in the ISM that everybody can
2 get into a monitoring position but I'm not sure what I would
3 monitor in someone else's area unless I got that information
4 back from them.

5 These are the critical interfaces. This will
6 tell you what's going on on the system. This will give you
7 a good overall view of what is happening in the system.

8 I think we have the capability of doing that now.
9 That's the near term fix. I think we can expand that but my
10 only issue is staffing and requirements to be able to
11 monitor this on a regular 24 x 7 basis. I think all our
12 operators have full time jobs now so asking how to do this
13 is another question.

14 But I think we can do it with relative ease of
15 work in getting the data into us. I think we have to be,
16 the reliability coordinator, has to be staffed at 24 x 7 to
17 allow the system to be securely operated -- all the time
18 with the information both internal and external, and
19 notification.

20 So I see two areas that need and usually fall
21 into generally a limitation on staffing but the key things
22 are coordination notification with other reliability
23 coordinators and the ability to monitor other systems
24 outside their own far enough in to at least give them an
25 early warning system.

1 I think those are the key areas on that.

2 There are numerous articles as to how well we are
3 coordinated in the Eastern interconnection -- I'll save the
4 Western for Mark -- but I think there's an ability here
5 between NERC and the regions to look widespread and what we
6 can do under certain controlled high-risk conditions.

7 One of the things that keeps coming out is how do
8 we make your system safe or how do you get to a more
9 conservative operation condition when something is happening
10 somewhere else? If it's an unknown, I want to know how it
11 impacts our system and I think from a systemwide point of
12 view, those are the large scale systems that we take a look
13 at.

14 I believe the emergency operating procedures
15 should exist between reliability coordinators, that they
16 know what actions the other one is going to take and have
17 agreed upon that -- this is more than just your internal
18 looking at it. This would be a reliability coordinator
19 emergency conditions say between New York and the IMO.

20 If we have an incident here, what do we do --
21 what do you do, and how do we ensure that we know what each
22 other is doing on that?

23 My final pitch is the functional model. The NERC
24 reliability function model -- describes the functions of
25 various authorities or entities running the system and

1 planning the system but there is no clearly defined
2 relationship between those functions and I think, as we go
3 forward in developing the standards, we have to define those
4 relationships better so people know that going forward how
5 this operates -- the best I can do is say we've defined the
6 functions. Now we have to define the relationships and
7 that's got to go forward.

8 I hope I used my seven minutes but I wanted to
9 keep it short and brief.

10 MR. CAULEY: Thanks Mike.

11 Next is Mark Fidrych, who is from the Western
12 Area Power Authority and also the chairman of the NERC
13 operating committee.

14 MR. FIDRYCH: Good morning.

15 As Gerry said, my name is Mark Fidrych. I work
16 for Western Area Power Administration and I'm presently
17 chair of the NERC operating committee.

18 By way of background, I spent six years as the
19 operations manager for Western and five as the reliability
20 coordinator manager in the Rocky Mountain Desert Southwest
21 region of WECC.

22 I'd like to address questions one and three today
23 and wrap up with a response to question six. I'll try to
24 keep my remarks brief and allow time for questions.

25 First question, 'what lessons are learned from

1 the August 14th outage reliability coordination and what
2 recommendations are there to improve reliability
3 coordination?'

4 Let me begin with a short philosophical
5 digression on power system operations evolution. I know
6 some have heard me say this a few times before and I
7 apologize for repeating.

8 In the days of vertical integration most
9 operators had a signal place to go for an answer and while
10 those answers weren't always the most economical for all
11 they generally tended to be somewhat conservative since the
12 last thing a chief dispatcher wanted to do is lose load.

13 But what took place simultaneously was the
14 development of familiar working relationships between
15 neighboring entities and those relationships evolved over
16 many years and frequently not without a lot of management
17 support.

18 Even looking at presently developing markets, and
19 I have to catch my place here --

20 (Pause)

21 -- okay, I've seen similarities. PJM has a very
22 functional market that evolved over many years. They
23 started small and loose and then gradually developed -- as
24 new needs came up they developed new programs. LMP I am
25 sure was not radically implemented overnight but they were

1 able to put it in place because it was the next agreed upon
2 solution for their market and they had a base of working
3 relationships.

4 With complex organizations you cannot implement
5 100 things at once dealing with multiple outside
6 organizations as well as multiple regulatory organizations
7 and hope to have the same outcome as a mature organization.

8 Reliability is always going to suffer when you
9 try to change too many things simultaneously.

10 So how does this fit with August 14th? Of the
11 issues directly related to reliability coordinators there
12 were three prevailing themes, communication, monitoring and
13 assessment. These are not dissimilar to the conclusions in
14 the '96 report in the West. Four of those conclusions were
15 to emphasize security, expand scope of analysis, improve
16 reliability information and strengthen operator training and
17 readiness.

18 The scenarios were slightly different but we see
19 the same issues again being problematic. What do we do to
20 improve? I think that there needs to be a greater sharing
21 of accurate data among all companies and that extends to
22 planning and outage data that's used to develop contingency
23 analysis.

24 Companies have got to be committed to
25 aggressively updating their data via whatever exchange media

1 can be implemented whether it be ISN or some other method --
2 and maintaining reliable data links for those exchanges.

3 Second, there needs to be exchange programs among
4 the reliability coordinators, i.e., working visits to the
5 neighboring areas, the neighboring reliability coordinators,
6 to promote the personal relationships as well as to the
7 subordinate control areas on an ongoing basis.

8 Finally, analyses have got to be spread widely
9 among entities to increase the number of eyes having
10 visibility to developing situations.

11 The third question asks, 'should these
12 reliability functions be shared overlapping between
13 reliability coordinators and their member systems to assure
14 redundancy or should these responsibilities and authorities
15 be divided between reliability coordinators and member
16 systems -- if so, how should they be divided?'

17 Yes, they should be shared. It just matters how
18 they're shared. For the member systems to buy into the
19 process and the analysis they need to participate. I think
20 however that the size of the member system and its impact on
21 the interconnected system and vice-versa, will dictate the
22 commitment that they will make.

23 But I don't believe that we can live with
24 delegating any of those responsibilities from the
25 reliability coordinator. This is analogous with my vertical

1 utility -- there has to be an entity responsible for a
2 specific area and the operation of that area.

3 Again, multiple eyes are better, but for seeing
4 and communicating -- not for directing.

5 This does not however address the issues of wide
6 area versus local reliability responsibilities. I expect
7 that they will continue to exist for some time but should
8 not pose a problem operationally.

9 So in conclusion let me address the last
10 question, what recommendations are there to ensure the basic
11 reliability safeguards noted in chapter two of the Interim
12 Report?

13 Back in '96 when the first regional reliability
14 plans were being developed we had ideas about what should be
15 in these plans and for a while that worked, because we were
16 busy implementing those plans and were focused.

17 But then as we began to reorganize the industry
18 we became focused on a new task at hand. There were new
19 liaisons being formed that were much different than those of
20 the past. Reliability plans were being changed to reflect
21 again how it was going to be done, not the tools and
22 procedures presently in effect.

23 We need to refocus on the reliability plans but
24 not to allow changes that affect reliability to move forward
25 until all the pieces are in place and the system has been

1 demonstrated effective.

2 We have to develop a greater standardization to
3 our methods and our reviews. We have to broaden the
4 visibility to what is happening on the system to many and
5 that includes all system parameters including generation.
6 We need to put our bright people to work and have them
7 develop systems which will give accurate status of the
8 vulnerability of the power system stability or we reduce
9 system transfers to a level where we are confident that the
10 system is not in jeopardy.

11 At this point I will add the usual caveat that
12 this list is not all-encompassing but, if we start with the
13 aforementioned items, we will be going a long way toward
14 embracing the concepts that were so well put in chapter two
15 of the Report.

16 Thank you.

17 MR. CAULEY: Thanks Mark.

18 Just in case you're wondering, there was a
19 published agenda with the speakers, with the questions posed
20 to each panel and in case you're wondering where that is,
21 there are copies of the agenda on the back table there in
22 the back of the room, and those are the questions that the
23 speakers are referencing.

24 Linda Campbell is with the Florida Reliability
25 Coordinating Council. She will be the next speaker.

1 MS. CAMPBELL: Thank you Gerry.

2 Good morning everyone. I have to say I am very
3 honored to be on this panel this morning and speaking to you
4 on the subject of reliability coordination.

5 The focus of my presentation is going to review
6 all of the questions that were in the agenda conference
7 materials, share FRCC thoughts and recommendations on each
8 of these questions and I guess ultimately the bottom line
9 I'd like to do is kind of remind the industry that, in our
10 search for solutions we often try to find easily a one size
11 fits all answer.

12 I want us to really be careful in not do that
13 with this. I don't think that that is necessarily the best
14 way to go.

15 Gerry, next slide please?

16 (Slide.)

17 Actually one more --

18 (Slide)

19 -- okay, one of the questions that started off
20 was 'what are the lessons learned from the blackout
21 regarding reliability coordination?' I think the primarily
22 key lesson that we believe is important is the review of
23 reliability plans. Mark was a good lead in for me on this.

24 I really believe that comprehensive reliability
25 plans are needed. It needs to provide wide area oversight

1 for the region or the reliability area and there needs to be
2 a very thorough understanding by all parties, not only the
3 reliability coordinator but all of the operating entities
4 that are under the purview of that reliability coordinator.

5 Reliability plans often we believe should have a
6 common format. This would help reduce inconsistencies
7 between the different reliability coordinator operations.

8 That does not necessarily mean that every
9 reliability plan will look the same and be a cookie-cutter
10 but at least every reliability plan should follow some sort
11 of a checklist so that they've asked themselves the same
12 questions and then they can take the appropriate action if
13 that's appropriate for their area.

14 Reliability plans must provide the authority that
15 is needed for the reliability coordinator to direct actions
16 and this reliability plan should also make the obligation of
17 the operating entities to implement those actions.

18 Those are all very important and key to any
19 effective reliability plan.

20 Next slide?

21 (Slide.)

22 I'd like to share with you a little bit about the
23 FRCC reliability plan. Our geographic peninsula has
24 mandated or necessitated a lot of coordination cooperation
25 for many many years between all of the operating entities.

1 We've got over 30 years of experience working together in
2 this area.

3 Our reliability plan was first developed in 1996.
4 We did a major overhaul of it in 2001 and we've revised it
5 again in 2003. All of the operating entities in the region
6 understand and follow the reliability plan and even if there
7 is a dispute sort of as Mike mentioned, the reliability
8 coordinator will direct an action and if there is any
9 dispute about that direct, then they will talk about it
10 later -- but they will implement the actions of the
11 reliability coordinator at that time.

12 We review, update and revise this as change and
13 we believe that there are probably many reliability plans in
14 the nation -- the country -- that would be able to serve as
15 role models but we also believe that perhaps the FRCC
16 security process or reliability plan could help serve as a
17 model as well.

18 The FRCC reliability plan identifies and outlines
19 a reliability coordinator responsibility. It provides the
20 authority for them to direct specific actions. We also
21 describe the procedures that must be used for monitoring and
22 analysis. This would cover real time operations, operations
23 planning and emergency conditions.

24 It also identifies requirements for information
25 exchange, communication and back up capability. We do have

1 an established back up reliability coordinator that's ready
2 to take over upon a minute's notice. And so we've got all
3 of this identified within our reliability plan.

4 Our reliability plan also identifies operating
5 entity responsibilities. We didn't think that the plan is
6 complete if it only talked about reliability coordinative
7 responsibilities. You've got to address what the operating
8 entities also must do.

9 It also provides the directive that the operating
10 entities will implement any directions given by the
11 reliability coordinator under normal and emergency
12 conditions and it requires the operating entities to provide
13 all the necessary data, real time data, operations planning
14 data.

15 Operations planning data would include
16 maintenance plans, equipment status -- all of that kind of
17 information which is important to the assessment and
18 monitoring of the system. It also identifies the
19 requirements for information exchange and communication and
20 this is not only with the reliability coordinator but with
21 each other, all of the control areas and operating entities
22 within the region.

23 The next question that was in the package was
24 'what reliability coordinator functions and tools are
25 essential for safeguarding reliability?'

1 We believe it is absolutely necessary for an
2 accurate state estimator model along with a contingency
3 analysis program to be working and in order at all times.
4 We believe it should run at least every five minutes. This
5 will capture any changing conditions so that if a particular
6 line goes out or anything that is going on can be assessed
7 and monitored and you don't have to think about going and
8 pushing a button necessarily to check it out. It's got to
9 include critical facilities in both the reliability
10 coordinator area and the surrounding reliability areas.

11 The accuracy of this data is imperative to the
12 solution of these cases and it takes a lot of effort and a
13 lot of manpower to keep that data going and to make sure
14 that it's appropriate and free flowing.

15 We have our own data exchange working group that
16 has the responsibility of keeping that real time data
17 sharing procedure in place and operating effectively.

18 We do have both a state estimator and a
19 contingency analysis model that runs every five minutes. We
20 look at over 700 contingencies. We do monitor facilities
21 within our neighboring system, the Southern Company system,
22 we've got over 20 lines and 11 units that we believe, if
23 there were problems with, would directly impact the FRCC
24 region -- or if the region had problems they could directly
25 impact the Southern Company system and we have communication

1 back and forth between the Southern Company or the sub
2 region reliability coordinator -- with ours.

3 So the output of this determines any action that
4 the reliability coordinator would need to take.

5 Again, for essential tools and functions we
6 believe operations planning analysis is very imperative as
7 well. We do a next day study every day, weekly studies
8 twice a week and monthly studies once a week. This data is
9 shared with each entity, reliability entity, in the region.
10 They can use this to develop ATC cases. But they are
11 updated on a daily basis with maintenance data, scheduled
12 maintenance outages, unscheduled maintenance outages.

13 The PTR load flow models should be utilized to do
14 this and this provides us this heads-up look for the next
15 day or even the next week so that if you see conditions that
16 may be popping up that will provide time to be able to deal
17 with them effectively on a proactive basis.

18 And the last thing regarding tools and functions
19 is effective communications and that needs to be under
20 normal and emergency conditions. You need to have internal
21 communications procedures within the organizations
22 themselves, external outside, and then the key about it is
23 it's got to be timely with everyone.

24 In the FRCC we have an internet communication
25 system that we call the "FRCC net" -- it's a frame relay

1 system. We share real time data through that system. We
2 have a messaging capability with that. We also have a hot
3 line phone system with all the operating entities in the
4 region and I think that's a very effective tool.

5 This allows all of the operating entities to hear
6 the same thing at the same time. It keeps them abreast of
7 what's going on even in the neighboring system so there are
8 no hidden conditions that are really going on.

9 And we also have a back up satellite phone
10 network that can take the place of the hot line should it go
11 down. We actually put that in with Y2K but we've kept it
12 around because we believe it's an important back up
13 communication tool.

14 The next question I wanted to address is should
15 these reliability functions be shared or divided? We don't
16 think so. We think that the wide area overview needs to be
17 provided by a single reliability coordinator for that area.

18 Redundancy in the functions, the sharing of that
19 can be beneficial and can be good. But the directives of
20 the reliability coordinator must prevail and you can only
21 get that from having one entity.

22 In the FRCC we do have three other control areas
23 that run state estimator and contingency analysis on a
24 periodic basis as well. So we do have that extra set of
25 eyes out there looking at the same things that can provide a

1 sanity check for our reliability coordinator.

2 So they are beneficial but ultimately the
3 decision making has to be by one entity so that there are
4 never any questions about that authority or the directives
5 given.

6 'Has the wide area overview been implemented
7 effectively in industry -- why or why not?'

8 Well, we don't think so. Obviously there's a,
9 it's been very effective in some areas of the country but as
10 evidenced by the blackout, maybe not in all. We believe
11 that the NERC review of reliability plans is maybe not
12 thorough enough. Perhaps there needs to be a little more
13 NERC oversight of that in getting into that more so there
14 can be a common structure for the plans.

15 The term 'wide area' can mean many things to many
16 people. We're seeing that in the development of standards,
17 trying to look at local area, wide area -- so that may cause
18 some problems when people are trying to figure these things
19 out.

20 But the key to all of this is that review of
21 these plans has got to be an essential part of this to make
22 sure that all the key parts and pieces of the reliability
23 process have been included and covered.

24 Along with the review of these plans it may be
25 important to include some more stringent auditing to make

1 sure that reliability coordinators are actually implementing
2 the plans as they are written. In FRCC we do reliability
3 coordinator audits at least every two years and we've done
4 that for many years now. And we make sure that the
5 reliability coordinator is implementing the plan as we have
6 written and agreed.

7 'Are the size and number of the liability
8 coordinators in control areas factors in determining
9 effectiveness -- if so, how?'

10 We don't believe that that's really the issue.
11 Complex geographic interfaces will or could be a problem in
12 some areas but we really don't think that the answer lies in
13 just limiting the numbers of either of those.

14 We've got 11 control areas and over 20 operating
15 entities and I believe that the key to our success has
16 always been the data sharing capability, our reliability
17 processes in place and the coordination of all the operating
18 entities and the coordination with our neighboring sub
19 regions.

20 It's really important to determine what needs to
21 be shared, what needs to be monitored, how to do it and,
22 once you figure all that out, you can make it happen so it
23 really isn't just how many reliability coordinators or
24 control areas that are the answer.

25 The last line is, 'what recommendations are there

1 to ensure the basic reliability safeguards noted in the
2 Report are effective?'

3 I believe the comments to the questions provided
4 already have given you some idea of what our recommendations
5 might be. I want to emphasize that -- one size fits all is
6 not the answer, that there are many areas that are doing a
7 good job right now. Perhaps we need to learn from those
8 areas and take from that before we go to try to figure out
9 something like the whole world is broken.

10 The FRCC does believe that NERC should play a
11 bigger role in developing the structure and the review and
12 implementation of the reliability plans. This will be a key
13 in operating reliability going forward and that the plans
14 need to be able to address any number of configurations of
15 reliability coordinators in the entities within their
16 purview. It's not just a magic size or form but it's all
17 the key parts and pieces are there. It really doesn't
18 matter what they look like.

19 Thank you.

20 MR. CAULEY: Okay for speakers for the rest of
21 the day, that's as long as you can go without me jumping on
22 you.

23 MS. CAMPBELL: Sorry.

24 MR. CAULEY: The last -- we have one more
25 panelist and then Don Benjamin has a couple comments on the

1 functional model but Mike Kormos is here representing PJM.

2 MR. KORMOS: Thank you and good morning. And I
3 will try to keep my comments brief. I'm going to repeat a
4 lot of the same themes that my colleagues did up here.

5 First slide Gerry.

6 (Slide.)

7 As far as the lessons learned, I think what was
8 most troublesome to me was really as reliability
9 coordinators we need to go back to the basics. We need to
10 go back to looking at really what I believe to be some
11 fundamental system operations basics regarding system
12 monitoring, the operator awareness, being able to continue a
13 system plan for an N - 1 and knowing where your system was
14 and then obviously the internal and external communications.

15 I really thing we need to take a step back and
16 really look at what we're doing and how we're doing them and
17 the tools we're using to do that.

18 The second point again which was troublesome is
19 just in redundancy, not only just in the computer hardware
20 and software but also the redundancy in having more than one
21 set of eyes looking at specific areas, and I think, as many
22 of my speakers have talked about, many areas in the country
23 are set up this way and I think it's something that should
24 be required to have that kind of overlap is really I think a
25 good fail safe as part of the system.

1 Emergency preparedness again has been talked
2 about. It needs to be clear up front, the actions that can
3 be taken, the actions that will be taken, what the
4 procedures are, who has the authority to take it. Again, I
5 think that needs to be absolutely clear cut in the minds of
6 all.

7 So to continue on the theme, I think again since
8 these are all things I would have thought had already been
9 in place, we really need to take a hard look at how we're
10 doing the evaluation of that. It's one thing to put it down
11 on paper in a reliability plan but we really need to make
12 sure we are in fact doing what the plan says, that the tools
13 that are there are supporting that and I really thing that a
14 third party critical evaluation, I think we have to learn
15 and maybe we can learn from other industries of how to do a
16 critical evaluation whether it's an independent or a peer
17 review is really important for moving forward.

18 Next slide, Ger --

19 (Slide)

20 -- question on the tools that are essential --
21 and I actually won't go into that now having heard Linda's
22 because I think Linda really covered a lot of the tools that
23 I believe are really important for reliability coordinators,
24 the real time monitoring and alarming.

25 I think we have to challenge ourselves as to what

1 is exactly real time? I think we've been way too loose on
2 that definition. The visualization tools, wide area looks
3 are, I think, the appropriate thing to do but it's also
4 difficult to do and you really need to have strong tools to
5 be able to look over these wide areas to assess all that
6 data and convert it into something useful.

7 Real time security analysis contingency analysis
8 again I think we have to challenge what the definition
9 really means and how it has to be implemented and then the
10 redundancy in the multiple levels of monitoring and
11 analysis.

12 The 'whether the function should be overlapped' -
13 - I personally think overlapping is critical to have fail
14 safes in this industry. We've learned hard lessons. Any
15 one of our systems can fail. None of us is perfect and
16 having that overlap I think is critical.

17 We're very much like Florida and New York, the
18 previous speakers. We use what we term the 'hierarchical
19 model of control' which basically overlays with PJM, our
20 transmission owners, all our transmission owners, and PJM
21 are running full blown, state estimator contingency
22 analysis, they are extremely good at it and they are
23 critical for working with us and helping us, backing us up
24 in assessing the state of the system at all times and I
25 think that's really important.

1 Also I think overlapping between reliability
2 coordinators is a good thing but it's more of a dangerous
3 thing. As we have all talked about, having clear authority
4 and responsibility is important.

5 We'd been working very hard with MISO prior to
6 the blackout as well as obviously after it, to lay out and
7 delineate what those responsibilities will be between us.

8 There needs to be or will be overlap between our
9 systems. We've developed the joint operating agreement, we
10 believe it is a very good start but setting out those
11 obligations responsibility is not the end all and I think we
12 will continue working very hard to try to continue making
13 that a better product.

14 The last one, we'll take off a little bit on Mike
15 Kormos' theme. We support the functional model of NERC but
16 we do have concerns as well as I think do our colleagues in
17 NPCC do regarding how those responsibilities are going to be
18 shared, how that overlapping will happen, and really setting
19 up clear lines of authority and responsibility. We really
20 think that needs to be further worked out in the process.

21 As far as wide area overview hasn't been
22 implemented, again, I can only necessarily talk about if
23 from PJM's perspective, we think we've at least made a good
24 shot at it. We have put in a new state estimator. Since
25 the blackout it's triple the size of our old one. It is a

1 10,000 bus bottle. We believe it's probably the biggest in
2 the country if not the biggest in the world. We modeled it
3 down extensively from the Atlantic Ocean out to Illinois and
4 actually beyond.

5 The model includes all of the critical flow gates
6 that we've identified with MISO that we are monitoring now.
7 All of the MISO flow gates that we have been asked to. And
8 we are doing contingency analyses on those as well so there
9 will be an overlap.

10 Again we needed to have clear responsibility.
11 These are MISO's responsibilities that we will be providing
12 sort of the secondary role for regarding that.

13 I will warn you though there is a significant
14 cost of inputting that. It cost us over \$30 million to make
15 these changes for our market integration and our footprint
16 expansion.

17 Again we are able to justify that and our members
18 are able to support that because of some of the other
19 benefits of market integration with these costs can get
20 quite expensive.

21 The next one is 'the size, number and complexity
22 of the reliability.' As far as size goes I just mentioned
23 cost. I do believe size matters. I do believe that you can
24 in fact justify the cost a lot better looking over a much
25 wider area -- it helps minimize those impacts.

1 Regarding the complexity, we're probably in the
2 middle of this and most people understand that. We've seen
3 that basically complexity is two parts. One is the
4 technical complexity the other is the constituents --
5 constituency -- I apologize, that's the pain of staying up
6 too late to watch Monday Night Football.

7 The technical issues have been difficult but
8 resolvable and again as I talked about it I think for the
9 most part we have those handled. We have found ways of
10 being able to model the system, the wide area, as much as
11 the neighbors.

12 The constituency demands have been much more of a
13 challenge to us though just because of the complexity in
14 there as whether they're governmental, regulatory, obviously
15 commercial issues -- have been the most difficult thing for
16 us to resolve. We understand they do need to be resolved.

17 But that really has been in our opinion the
18 harder part of resolving some of these complex seams. The
19 technical aspects of it are we think much easier to resolve.

20 We believe once the geographies are established
21 and the clear authorities and functions are established,
22 that in fact this is something that is doable and
23 resolvable.

24 The last item again high level, I didn't really
25 go after too much -- 'mandatory reliability standards' we

1 think are critical coming out of this, we need them, we need
2 to make sure they are enforceable. And again sort of the
3 same thing, we really believe NERC and I don't mean just the
4 ladies and gentlemen at Princeton -- the whole NERC
5 community really needs to take a step back, reassess how we
6 are looking at the control area and the reliability audit
7 functions, they really look to make a number of improvements
8 in how we do those evaluations and I support everything with
9 having consistency in our plans but I really think we got to
10 go beyond just looking at a plan by making sure that the
11 plans are being carried out and are capable of being carried
12 out to the full extent.

13 That concludes my comments.

14 MR. CAULEY: Okay, thanks Mike.

15 And then just to close the panel, we have a few
16 remarks from Don Benjamin on the NERC staff regarding the
17 functional model.

18 MR. BENJAMIN: Thank you Gerry and good morning
19 everybody.

20 Mike Calimato and I think Mike Kormos and others
21 have referred to the NERC functional model and for those of
22 you who may not know what the NERC functional model is I
23 want to spend just a few moments discussing it with you this
24 morning.

25 After the Energy Policy Act was passed in the mid

1 1990s it became quite obvious to the NERC operating
2 committee that as the industry was beginning to unbundle
3 itself and utilities were selling off their transmission
4 assets or their generation assets or whatever and new
5 organizations were forming like ISOs and RTOs and the like,
6 that the basic reliability organization which we have known
7 as the control area for the last 50 years or so was
8 beginning to become difficult to identify and the NERC
9 operating policies that were written to the control area
10 were beginning to lose their focus because what is a control
11 area any more?

12 And in many cases it was just becoming a
13 balancing organization and didn't have transmission
14 responsibilities.

15 And so in 1999 the operating committee
16 commissioned a small task force to start looking at the
17 operation of the control area and perhaps take a different
18 view of how NERC policies ought to be written and so what
19 came out of that control area criteria task force as it was
20 called was a concept that NERC should develop a set of
21 functions and then write its operating policies to those
22 functions rather than to write them to any one kind of
23 organization such as a control area, an RTO, an ISO or
24 whatever might be forming in the years to come.

25 In 2001 the board of trustees approved the NERC

1 functional model and since that time as we have been
2 developing our new reliability standards they have been
3 developed around the functions of that model.

4 We recently completed an update to the model. We
5 wanted to make sure that the model can accommodate the newer
6 market structures that were forming. We found that the
7 model does indeed incorporate and accommodate markets.

8 In fact, it's really independent of market
9 structures. It doesn't matter what kind of market is there
10 or whether there is a market at all, the functional model
11 still works.

12 And up here on the screen are the actual
13 functions themselves and one of the ones that we've been
14 concentrating on today is this one called 'operating
15 reliability.' That's the name of the function and Gerry can
16 go on to the next slide.

17 (Slide.)

18 That's the name of the function and what we have
19 identified underneath that is the reliability authority. We
20 call that the 'responsible entity' so organizations, ISOs,
21 RTOs, even control areas regional councils, would --
22 register with NERC to be the reliability authority for a
23 certain area and as the reliability authority they are
24 responsible for the tasks defined as the operating
25 reliability function, so every function has a responsible

1 entity that goes along with it.

2 Now the important part of the functional model,
3 at least when it involves or as it relates to the August 14
4 blackout, is that one of the guiding principles of the model
5 is that an organization that registers to perform one of
6 these functions is responsible for all of the tasks that
7 define that function.

8 An organization may delegate tasks to other
9 organizations but it cannot delegate its responsibility for
10 ensuring that those tasks are all completed. That's true
11 for the reliability authority, it's true for the balancing
12 authority that will ensure that it will balance within its
13 area, it will be true for the transmission operator, it will
14 be true for all of these functions.

15 And so the functional model should provide some
16 clarity, should help provide some clarity of who is
17 responsible for doing what? And we hope that that will
18 eliminate potential finger pointing in the future and
19 clarify the responsibilities.

20 Let us go on one more slide here.

21 (Slide.)

22 And I'll end on this one here. One of the points
23 that Mike Calimato and Mike Kormos both made and that I
24 agree with is that you will not find clear delineations of
25 authorities within the functional model. The functional

1 model simply identifies functions, tasks within functions
2 but does not go very deep into the inter relationship among
3 those functions because it is not really intended to do
4 that. Because it's not a physical model. It's just a model
5 function.

6 There are other documents that NERC is developing
7 that will better define the inter relationships among the
8 functions and the responsibilities of those functions and I
9 want to show those to you here. The functional model is
10 what we've just been talking about and it defines functions
11 as a set of tasks and it also defines responsible entities
12 and goes into some detail but not a lot about the inter
13 relationship between those functional entities.

14 Each of the organizations that are out there, the
15 control areas, RTOs, ISOs, generators, transmission owners,
16 et cetera, will register with NERC and tell NERC which of
17 these functions it is going to provide. For the reliability
18 authority, the balancing authority, interchange authority
19 and transmission operator, NERC will develop a set of
20 certification criteria and audit those responsibilities to
21 make sure they are capable of performing those functions.

22 So that will be in the certification procedure
23 here. That is where I believe some of the relationships
24 need to be established. So in other words, the reliability
25 authority when it is certified must be shown that it has the

1 authority over the balancing authorities, over the
2 transmission operators, that it can take whatever action is
3 needed.

4 Similarly when the transmission operator is
5 certified we need to make sure when the balancing operator,
6 the balancing authority, is certified, NERC needs to make
7 sure that it will operate to the instructions given to it by
8 the reliability authority.

9 So that's where some of the details need to be
10 included that Mike Calimato and Mike Kormos were talking
11 about, that are very, very important.

12 The regional reliability plans, we're now
13 developing some of those new templates for those plans,
14 that's what Linda Campbell was talking about. They have a
15 consistent set of reliability plan templates. Those
16 regional plans will identify, designate, list, whichever
17 word you want to use, reliability authorities, to cover that
18 region and the balancing authorities that cover that region,
19 to make sure that there are no gaps or overlaps.

20 And finally we have the reliability standards
21 themselves, the new NERC reliability standards themselves --
22 are being written to the responsible entities -- so that
23 the new standards will say 'the reliability authority shall
24 -- the balancing authority shall -- the interchange
25 authority shall -- et cetera.'

1 They will no longer say 'the control authority
2 shall.'

3 The reliability standards provide measures of
4 performance and determine the ability that these various
5 organizations have to perform what is in the standards
6 themselves.

7 So it's all four of these documents together.
8 The functional model, the organization registration and
9 certification requirements, the regional reliability plans
10 and the reliability standards that work together that define
11 the obligations of the responsible entities and their inter
12 relationships.

13 Thank you very much -- we'll skip this slide
14 here.

15 (Slide.)

16 MR. CAULEY: Thanks Tom.

17 First of all, any questions of the panelists from
18 the distinguished panel investigators?

19 19

20 MR. MEYER: I have an observation more than a
21 question. It's just that, as we move into the
22 recommendation phase, I am always in the back of my mind
23 it's 'how do we proceed? How do we move the ball forward?'

24 Recommendations can be posed sometimes in fairly
25 general terms that, as we need to take action in some

1 particular area address some particular set of problems, but
2 that still leaves open the question how are we going to do
3 that and a lot of times the ball is going to have to be
4 carried by various sets of parties depending on the issues.

5 So when you offer suggestions and comments, give
6 us your ideas on how to move forward on this in an
7 implementation mode. That's important information for us
8 also.

9 MR. CAULEY: Tom?

10 MR. RUSNOR: Thank you very much. It's kind of a
11 short time to put up some really intelligent questions but
12 nevertheless it's my view that there is certainly no lack of
13 intelligence or knowledge in how to maintain a reliable
14 power system.

15 The will to do it in certain areas might need
16 some improving. The will to upgrade the reliability
17 standards about the current floor or ceiling as you wish I
18 think is going to be vital as we move forward in the future.

19 I'd like to congratulate PJM on making the
20 investment which I think is absolutely critical for more
21 than just PJM but for a lot of areas across North America.

22 The big issue in my mind is in the absence of
23 legislation, how do we make reliability standards mandatory
24 and how do we ensure that all the responsible and
25 accountable entities are going to abide by them?

1 Those I think are more policy issues than
2 technical issues but as we move forward I have some doubt
3 that we are going to be uniformly at a level that's
4 acceptable to all of us in North America.

5 So maybe somebody at NERC or some of the panel
6 members would care to address how we move forward in that
7 area?

8 There's also I think the issue of, and let me
9 back track a little bit. I've been out of the power system
10 planning and design operating for at least five years since
11 I've retired and probably about 10 years since I actually
12 did some really useful work so I could be out of touch to
13 some degree.

14 But in my planning days I notice that there are
15 considerable differences in the regional councils'
16 reliability criteria. Is that an issue?

17 To what level should they be consistent and
18 coordinated? I am not sure that I am in a position to
19 answer that but I would certainly like to see some comment
20 from the audience and from this panel and from other panels
21 on those issues.

22 Thank you.

23 MR. CAULEY: Any response? I'm not sure they all
24 require responses but -- go ahead, Mike.

25 MR. CALIMANO: I'll go first. I'm sure I'll be

1 corrected when I go wrong but as far as regional councils I
2 think that the council will look at its needs and
3 requirements and in the case of MPCC clearly we have more
4 stringent requirements than NERC has in the operating
5 policies.

6 There are more reasons for that but we've
7 implemented those policies over the years, as Gerry pointed
8 out, MPCC came about because of the '65 blackout.
9 Additional more stringent requirements came out of the '77
10 blackout.

11 I think it's up to the regional councils to
12 review that. I think the regional council is closer to the
13 situation and can get more stringent criteria that's
14 necessary for it.

15 I believe that also in New York City we have
16 other major concerns and we have more stringent requirements
17 in there due to the state, due to the reliability council or
18 within the state, an N - 2 requirement and develop that.

19 I think you have to let the councils develop the
20 areas where they need more stringency but they should be
21 allowed to do that and they should be allowed to implement
22 either some sort of mechanism to ensure enforcement.

23 In the MPCC membership agreement it has the word
24 'mandatory' in it. We do have mandatory requirements in
25 MPCC to meet those more stringent requirements and I think

1 counsels can develop that going forward or whatever the
2 entity is. I think you have that flexibility.

3 MR. FIDRYCH: I'll take a shot. I think that the
4 reliability plans that we talked about and the regional
5 councils can provide the vehicle for giving some of the
6 mandatory compliance. I think one of the problems that we
7 run into is that we don't have enough of the entities that
8 are described in the functional model as participants in
9 some of those organizations. I think we're going to have to
10 get those involved in it for those to have all of the
11 breadth of function and responsible agencies involved.

12 In terms of the policies I think where we existed
13 with the NERC policies long ago is we came to a consensus
14 and the policy tended to be the least common denominator.

15 I think we need to look at the standards that are
16 being developed now and apply a much more stringent
17 requirement in those standards than what we've allowed to
18 get by within the existing policies and the old policies.

19 I don't at all think that there's anything that
20 would prohibit an organization from requiring a more
21 stringent requirement where there was a local necessity for
22 it but I think we need to beef up the standards in the first
23 place.

24 MR. CAULEY: Okay, anything else? Dave or
25 anybody?

1 MR. HILT: I had some questions.

2 MR. CAULEY: Go ahead.

3 MR. HILT: Actually I have four of them for the
4 panel and for the group here at large if the people care to
5 address them.

6 First I'm going to roll into a couple. I'm going
7 to go through them all and I'll just let you answer, to
8 provide whatever you want.

9 I heard several people talk about wide area
10 monitoring and the difficulties in building large state
11 estimators and I've been there, done that, so I understand
12 what you're going through.

13 But my question really is for people like Mike
14 and others, have the vendors out there kept up with the
15 tools in terms of providing software and developing tools to
16 help the reliability coordinators to put the packages
17 together, to build large state estimators and contingency
18 analysis packages?

19 I know some years ago there was work in those
20 areas looking at different solution techniques et cetera to
21 be applied and I think it's just an area I'd like to hear a
22 little bit of discussion on is, is it something that we need
23 to move forward on in terms of an overall recommendation to
24 say there needs to be some additional work done to provide
25 those tools?

1 Secondly along the same lines of tools in terms
2 of communications, I heard that communications is difficult,
3 it's slow, we need to improve it, you know, we talked about
4 hot lines, et cetera -- has the communications provided us
5 with the tools that we need to do effective communications
6 and, if not, do we need, do we as an industry or we as
7 government and others, need to approach the communications
8 industry and say 'this is a very important, very critical
9 infrastructure and we need better tools to assist us in
10 communicating on reliability emergencies?'

11 I heard some discussions just now and earlier
12 also about looking at the standards and strengthening the
13 standards.

14 Mark Fidrych I believe discussed visits between
15 reliability coordinators. Several years ago I attended a
16 conference where I think it was the president of America Air
17 Lines said at the conference that it was an engineering
18 technical conference for the electric industry and he was
19 the keynote speaker and he said, "It's really wonderful you
20 still do this. I don't know that we do that any more." He
21 said, "because we don't do it in the airline industry
22 because it's competitive information and we don't share that
23 information that may be competitive."

24 Reliability is not competitive. I think
25 everybody needs reliability. We need to know. I think

1 someone else mentioned what it takes to operate this system
2 reliably hasn't changed.

3 In terms of doing those visits, Mark and I guess
4 others, one of the questions may be, "Do we need to identify
5 some of the best practices that are being done out there
6 among the reliability coordinator folks?" Share those and
7 make sure everyone is learning from what the best practices
8 are and how we can move forward.

9 I know INPO does this for the nuclear plant
10 operations and such. Maybe we need to do that for the
11 reliability side of the electric industry and I would just
12 be interested in thoughts on that.

13 And finally we talked a little bit about state of
14 emergency. What is a state of emergency -- identifying what
15 a state of emergency is and communicating that -- I guess
16 I'd be interested in do we have adequate training out there
17 for the operators? Do we really need to provide them with
18 some simulators where they can set down and actually
19 practice on recognizing emergencies, when to take action and
20 what actions to take?

21 MR. CAULEY: Of course that last question will be
22 addressed in our next panel. But any response to the other
23 three questions?

24 MARK FIDRYCH: I'll take the third one--

25 MR. CAULEY: Go ahead.

1 MR. FIDRYCH: -- since it's fairly quick on the
2 communications and identifying what the best practices.

3 Dave, when we make the visits in the West we do
4 look at what companies are doing, what the reliability
5 coordinator is doing and I frequently had a coordinator come
6 back and tell me "we got to scrap the way we're doing this
7 because these guys are doing it a whole heck of a lot
8 better."

9 We didn't presume to try to give that to anybody
10 else -- as long as we were improving the operations within
11 the interconnections we hadn't taken that next step further.

12 We didn't presume to try to give that to anybody
13 else as long as we were improving the operations within the
14 interconnection we hadn't taken it that next step further.
15 I think it's probably appropriate to do that.

16 MR. CAULEY: Linda?

17 MS. CAMPBELL: I'll tackle the communications
18 ones also though more from the perspective of either vendors
19 helping out and I guess Dave, as far as, I don't know that
20 they're not right now but I'll tell you that the big
21 struggle that we've had in dealing with the vendors for our
22 frame relay or FRCT net is getting in to understand the
23 importance of keeping the availability and reliability high
24 on their system because if we're relying on that frame relay
25 for real time data and it's updating every two to four

1 seconds, we can't take a 30 minute outage on that frame
2 relay and so getting the vendors to understand the
3 importance of that has been a challenge.

4 As far as the hot line goes we've had a hot line
5 system in place for a long, long time and I guess it's a a
6 dinosaur and they don't even offer that service any more and
7 there's a lot of talk about voice over IP and all of this
8 kind of thing.

9 We're a little reluctant at this point to put all
10 our eggs in one basket to go there yet. So I think there
11 could be improvements from the communication industry to
12 help us.

13 MR. KORMOS: I'll take a shot at the first two,
14 Dave. Regarding wide area monitoring it's sort of a mixed
15 bag. I think we've had great cooperation from our vendors
16 but it's almost been an R&D effort for us to do multi
17 processing in state estimator, multi threat e-programs.

18 They're more than willing to work with us but
19 they're also more than willing to charge us a premium almost
20 to make that. I think a \$30 million price tag for our
21 latest government effort is a good example so I think in
22 industry we can do a lot to work on some of those techniques
23 and working on some of the solution techniques of how to get
24 wide area models to converge, particularly when convergences
25 are outside of some of your areas.

1 There is a lot of work that can be done in that
2 area in standardizing and really working towards that so I
3 think as an industry it is an area we can work with. I
4 don't want to fault the vendors though. They're in the
5 business to make money and not necessarily to do R&D unless
6 there's a demand for it. That's part of the problem we've
7 been dealing with.

8 As far as the communications I guess my take on
9 it is really we just predominantly as an industry rely too
10 much on voice communications and I think that was in the
11 report. We rely way too much on the phone.

12 There is an inherent delay when you are trying to
13 make phone calls, the information is not going to be passed
14 timely versus where the amount of data -- again we're
15 receiving 40,000 points every three seconds right now for
16 our contingency announcements and their solutions.

17 We've found that technology, that communications
18 there, we can move that. But we're still hung on everything
19 is still voice and telephone and when I look back at some of
20 what happened with, at least in our areas, some of the
21 delays were just due to people discussing, talking,
22 ultimately coming to a conclusion and then making the phone
23 call -- where that data could have been sent 15 minutes
24 earlier if we automated.

25 MR. CAULEY: I do want to leave some room for the

1 audience participation here and now's a good time to start
2 that and hopefully you won't be bashful and we welcome
3 comments, recommendations in this area or questions to the
4 panelists and we'll start with Terry Volkman.

5 And why don't you state your name and your
6 organization so the recorder can get that for us.

7 MR. VOLKMAN: Terry Volkman at Excel Energy.

8
9 It seems that our reliability coordinators have
10 developed differently over time. Some have come from
11 operators from companies that consistently operate a system
12 that their reliability coordinator (inaudible) and other
13 ones that are built from scratch.

14 The question is where do you draw the line in
15 operational economics and creation of operational nuances of
16 how they're prepared to operate between what the (inaudible)
17 reliability coordinator versus what belongs in the control
18 center of the transformation owner operator.

19 The place where you would draw the line and what
20 type of training that the reliability coordinators get to
21 understand those operating nuances.

22 MR. CAULEY: Unfortunately we have two tight
23 grids up here who probably are not the most qualified to
24 answer that because they do both but maybe you can give us -
25 - Mark, you want to start out?

1 MR. FIDRYCH: Yes. I'll make one comment. I

1 think the presentation that Linda provided in talking about
2 the reliability plan provides the vehicle for doing a lot of
3 that, Terry. I think that that's where you need to really
4 specify and rather than having the cookie cutter approach
5 that they're all the same, I think that you get the
6 specificity in that plan that enables you to go out and
7 address those particular issues.

8 Now the level of operator training on the other
9 hand, it's really tough for me to say if you don't get a
10 very seasoned operator that you're going to have a very
11 difficult time putting somebody in place who's going to be
12 able to assimilate the data that they're receiving visually
13 and auditorially and process it in enough time to be making
14 a good decision.

15 MR. KORMOS: Let me take a shot at it, Gerry.
16 And I am a tight pool.

17 But I think there's two answers to that. The
18 first is, I think, for authorities and responsibilities the
19 line has to be drawn. I'm not necessarily sure it matters
20 where it's drawn but it needs to be drawn and it needs to be
21 clear who has authority, who has the responsibility and I
22 don't/can't -- I don't think there should be any
23 misunderstanding in that area.

24 Regarding operational knowledge though which I
25 think was part of your question. I actually think you

1 should never draw a line. I think my transmission owners,
2 their operational knowledge is as good as ours. We overlap
3 each other. I think that overlap is a huge fail safe to the
4 system that we have two very knowledgeable organizations
5 looking at a part of the system making an assessment,
6 backing each other up, working with each other.

7 You'd be amazed at some of the discussions we
8 have and I think that that kind of line shouldn't be drawn.
9 You want that overlap. I think it's good for the system.

10 MR. CALIMANO: I just want to quickly go a little
11 bit further as having the operators work together. In New
12 York the operators do have twice a year a week of training
13 that they do work with the local operators to get that
14 understanding transfer of information, talking -- I think
15 we've mentioned that. You got to get out and see how the
16 other guys are doing it.

17 MR. CAULEY: Any other questions or comments?
18 Back there? Is that Meyer Shoshone? Long time, Meyer. At
19 ConEdison still?

20 MR. SHOSHON: Yes. Is this on?

21 MR. CAULEY: Why don't you come up to the front
22 one?

23 MR. SHOSHON: (Inaudible.) The panel has made a
24 lot of insightful comments on how to contain (inaudible) in
25 the long and short time frame but there are a couple of

1 things that I'd like to mention that (inaudible). I just
2 want to underline that every coordinate that we move forward
3 that moves (inaudible).

4 MR. CAULEY: I think Tim Bush in the back? Why
5 don't you state who you're with, Tim, for the recorder?

6 MR. BUSH: Tim Bush (inaudible) Consulting.

7 We spent a fair amount of time this morning
8 talking about state estimators and real time monitoring and
9 the comments I'd like to make first of all and I hope we're
10 not giving short shrift to the value of scan data in real
11 time monitoring alarming on that scan data.

12 The state estimators run every five minutes or
13 so. Real time data comes in every three seconds or ever
14 five seconds, whatever. It's also possible and Mike could
15 speak to this new contingency analysis that scan rates for
16 thermal -- we can't do it for voltage -- and there's great
17 value in having that information and having an alarm
18 quickly.

19 The impression I get is we're leaning more and
20 more toward putting all our eggs in the basket of state
21 estimation and it certainly is a valuable, a wonderful tool.

22 However, it depends on having an accurate network
23 model and what I would like the panel to speak to is what
24 suggestions would you have for ensuring that each state
25 estimator throughout the interconnection knows the status of

1 the transmission system -- as lines go in and out of service
2 it is critical that those state estimators have that
3 information and what the results are going to be (inaudible)
4 so I would like to get some thought how we make sure that
5 everybody knows and everybody knows quickly as to what the
6 transmission status is, what electronic (inaudible) in the
7 network and what we can do to accomplish those negative
8 entropics.

9 MR. CAULEY: That's a really good question for
10 panel C but we're going to let the panel A guys take a stab
11 at it too.

12 MR. KORMOS: I'll take a quick shot. First off I
13 want to reiterate what Tim said. It sort of blew over my
14 slides on tools but I absolutely agree that the scan data
15 contingency analysis distribution factors are critical and
16 you can't come up with voltage surge gates as well for
17 distribution type analysis. That was part of my discussion,
18 you're absolutely right. State estimators are not
19 infallible they do fail, they can fail, bad data does cause
20 them difficulty even though ours is 99.99 percent or
21 something like that -- we still heavily rely on our scan
22 data and I did sort of blow over that kind of redundancy and
23 overlap. I wanted to work on my presentation and so I just
24 wanted to support that.

25 As far as the network model it is a difficult

1 question and I think particularly with MISO and with what
2 our joint operating agreement now states, we've tried to
3 really tackle that, really tried to come up with how
4 basically we are exchanging full network models with each
5 other now.

6 But we still need to then decide how much of that
7 model do we need to put into each other, how much of the
8 data and how often the data needs to be transferred -- that
9 is the real challenge right now that we're working with and
10 I think Mike pointed out one of the things the reliability
11 coordinators very quickly need to do is sit down and figure
12 out what those critical facilities are right now and get
13 those in place and get the communications, the data, we have
14 ICCP links in with everybody at this point. There's no
15 reason we can't be transferring this data which is just a
16 matter of getting down, assimilating that and putting a
17 process in place and that's a lot of what our joint
18 operating agreement is with MISO is to put the process in
19 going forward, it's not just enough to do it one time. The
20 world will continue to move and evolve and we're putting in
21 higher level executive steering committees as well as
22 working groups to then further that effort.

23 MR. CAULEY: Okay Scott, I think you were next --
24 Scott Moore?

25 MR. MOORE: (Inaudible) I heard comments from

1 the last week or so and my understanding is that FERC has
2 raised an issue about the cost of RTOs that (inaudible)
3 transfer RTOs (inaudible) is that cost (inaudible) borne by
4 transmission operators with some working towards this
5 transfer of RTOs but then we should stop in order to reduce
6 the cost to the ultimate customer.

7 My concern is that if we just cut today, if we
8 need some redundancy in the margin in the system, that you
9 have to have that fail safe with the transmission operator
10 is looking at the (inaudible) as well as for the reliability
11 coordinator that has a part in RTO is more training on a
12 wide area system because you have to have that expertise in
13 that dual output area to help work through and supplement
14 work being done by (inaudible) feeds.

15 Also (inaudible) RTOs are generally looking at
16 the voltage system and we know that 130 and 230 and 345
17 still could be looked at at the local level. Part of my
18 concern is the comment that FERC's expectations that some of
19 these redundancies are transfers of responsibilities from
20 the POs to the RTOs would require the operators, the
21 transmission operators, to quit doing those in order to
22 reduce the cost.

23 I want to make sure there is recognition
24 (inaudible) that there is some understanding from an
25 (inaudible) standpoint that there is a need for redundancy

1 in modern transmission systems and that in order to make
2 sure a local generator problem doesn't go widespread is that
3 you do monitor the load bearing (inaudible) in a wide area
4 and that some of these call for a limited (inaudible) are
5 necessary in order for (inaudible).

6 MR. CAULEY: Okay. Next?

7 MR. ALLEN: Hello, I'm Eric Allen from the New
8 York ISO. The comment I have relates to reliability
9 coordination and it's (inaudible). I'd like to comment on
10 the major role that software failure played on August 14 as
11 pointed out in the Report and particularly relates to the
12 statement that the developmental software was not considered
13 assured as being used as a secured power system.

14 Most everybody that I've talked with is familiar
15 with the extent of experience that using software has been
16 with bugs and I'd like to see technology lags that do
17 (inaudible) and clearly "why is software so bad?"

18 August 14 illustrates the potential consequences
19 that poor software quality can have. And the latest
20 (inaudible) any software that's used in power system
21 operation should be very rigorously and thoroughly tested.

22 For example, every line (inaudible) area which is
23 being covered by the software monitor should be tested and I
24 think those comments made about using new software systems,
25 I think that it is more important to use proven technologies

1 as opposed to using new systems. Thank you.

2 MR. CAULEY: Okay, Margie? Margie Phillips I
3 know used to be at PICO but I don't know where you're at
4 now.

5 MS. PHILLIPS: (Inaudible.) I just wanted to make
6 three observations. One is, I think that all the
7 engineering in the world can not help you get over a real
8 problem you have which is that load shedding is a tool to be
9 used but is a politically unacceptable tool. And somehow it
10 seems to be that that is going to be something that happens
11 to (inaudible) and it also goes to coordination to a system
12 when you have to pull the trigger, it will have economic
13 consequences. So I recommend that you tell me (inaudible).

14 My second one is when we talk about August 14
15 responsibilities we have to talk about DOE. And that's a
16 topic and I don't know where the Republicans are showing any
17 penalties (inaudible) when we talk about homeland security
18 responsibilities -- there are some consequences to failure
19 to step up to the responsibilities. You have not
20 essentially done what you have set out to do.

21 And my third one (inaudible) Mark, I'd like to
22 take a pot shot at you. I think that in a world of
23 diverting utilities you still have blackouts. I would argue
24 that it is a real shame for our market that we have had a
25 slowdown at (inaudible). Those of you who are in PJM New

1 York and New England who do have the power to (inaudible)
2 these systems, you know that -- the system operator has more
3 information over a wider area than anybody else. That
4 includes generation and information problems (inaudible) and
5 in addition I would like to FRCC where the information is
6 shared among transmission owners (inaudible) PJM all market
7 participants see and want this information we could help to
8 distribute to alleviate the things that we see that are
9 going wrong and frankly it is the degree that we are getting
10 to a structured market according to PJM (inaudible) is where
11 we want to go and in fact that was what was lacking in MISO
12 is that it had none of the information that other existing
13 Northeast RTOs had. Thanks.

14 MR. CAULEY: Never was bashful. Jack?

15 PARTICIPANT: My name is Jack (Inaudible) and
16 I'm from Dominion. And the points I want to make are
17 related to real time operations for reliability tools, real
18 time models and best practices. I think standards need to
19 be put in place that define detailed to (inaudible) criteria
20 for real time models particularly in terms of the size of
21 the models required and the fidelity of the models and the
22 upkeep of the models. We also need standards to define
23 criteria for proper level of observability of the facility
24 that's being modeled. We need standards to define
25 acceptable levels of performance and solution quality for

1 the tools used in the models in particular status and real
2 time contingency analysis.

3 I think the best way to arrive at those standards
4 is to do a multi (inaudible) wide assessment of best
5 practices and I think to do that we need to establish
6 another working group within NERC with a power system
7 engineering perspective not a perspective of managers
8 directed by vice presidents -- that is, the working of the
9 people involved in this should do the survey analyses of
10 best practices and come up with recommended standards --

11 MR. CAULEY: We'll take one or two more questions
12 and then I want to keep us on schedule with, and there will
13 be an opportunity to ask questions and make comments after
14 each panel but I do want to keep things going smooth.

15 We'll take the last one there and then let's see,
16 we'll take these two here and then we'll take a break.

17 MR. GILBERT: My name is Vince Gilbert. I'm from
18 the Nuclear Power Industry. But I don't know where the
19 switch is.

20 MR. CAULEY: Just come up to the front one.

21 MR. GILBERT: My name is Vince Gilbert. I'm from
22 the Nuclear Energy Institute and I represent the nuclear
23 power industry. The (inaudible) safety is analogous to your
24 electric reliability and I think there are a number of
25 comparisons we can make that will give assistance to you.

1 Our standard nuclear performance model relates to
2 the NERC function of how we conduct and systematically
3 identify and ensure good practices and performance matrices
4 and how we conduct evaluations with (inaudible) standards --
5 how we develop simulator training and accredit our training
6 programs, how we involve suppliers to reduce product
7 development costs, how we conduct emergency planning, and
8 exercise the value that we see in developing industry
9 consensus (inaudible) with our regulator the Nuclear
10 Regulatory Commission and in part finally say that the
11 nuclear industry has formed a task force which is responsive
12 to the (inaudible) and need to distinguish --

13 MR. CAULEY: Thank you. And one last comment and
14 then we'll take a break.

15 MR. MURPHY: My name is Paul Murphy. I'm with
16 the (inaudible) market (inaudible) operator in Ontario. At
17 separate times virtually all the panel members commented on
18 the need for good operator training (inaudible) demonstrated
19 the same thing but I would just like to emphasize one point
20 made by Mike Kormos with respect to the inquisitive
21 operator, eh?

22 I know in my own experience there are many times
23 when blackouts have been avoided or serious consequences
24 have been avoided not just because we had good tools
25 monitoring things or just because we had good procedures in

1 place but because our operators are constantly assessing
2 what they were exposed to asking questions that needed to be
3 asked gathering information that we needed to gather and
4 making connections (inaudible) some unusual circumstances
5 that are not necessarily obvious as to the normal process
6 observing and I just want to make clear that I would even
7 extend the need for some implicit cultural thing beyond just
8 operators where they follow operational planning or as when
9 management (inaudible) it's a very difficult thing to get at
10 in terms of measuring data when you focus not only to make
11 these things happen but this is very much more of a goaler
12 cultural thing -- very much related to management of the
13 organizations involved in (inaudible) organizations and
14 these are the types of questions that need to be continually
15 asked.

16 The second point I want to make is with respect
17 to standards and (inaudible) which is what really
18 demonstrates (inaudible) it may be appropriate to have more
19 stringent standards (inaudible) and the varied reasons for
20 that. That's why it was demonstrated very clearly that
21 blackouts don't respect regional boundaries any more than
22 they respect international boundaries and the fact that 50
23 million people can be affected by this sort of event
24 demonstrates more clearly than anything else that these must
25 be very high standards in our history throughout the

1 industry internationally.

2 MR. CAULEY: Okay, thank you. These are all very
3 good comments and keep your comments coming. We'll have
4 four more opportunities to do that.

5 We're going to take what is now a 13.5 minute
6 break until 10:15 a.m. and we will reconvene panel B.

7 Could I make sure I get all the speakers? Panel
8 B and C because I'm going to try to get both panels in
9 before lunch so I need Kim Warren, Vicky, I don't know if
10 you have slides. Zwirgel I have. I need Pat Doren, Steve
11 Lee and Victoria.

12 (A brief recess was held.)

13 (Back on the record.)

14 MR. WARREN: (Blank tape gap.)

15 This is by far the best approach in dealing with
16 emergencies. This is accomplished through good planning and
17 coordinated operations, adequate investments, effective
18 certification and compliance audits and reviews. Mandatory
19 enforceable standards set the requirements but they
20 establish the minimum requirements.

21 Compliance with those standards requires
22 functions to be assumed by entities equipped with the
23 required attributes, authorities and capabilities. All
24 entities should comply with approved reliability
25 requirements that are critical to the prevention of wide

1 area outages.

2 Prevention hinges on being prepared. All parties
3 must be ready for the next contingency. Prevention --
4 preparedness hinges on training, comprehensive knowledge of
5 your systems, your service area, your facilities, your
6 operating companies along with continuous rigorous education
7 by all. Conditions change often in unanticipated ways. All
8 entities must be capable of ensuring their systems remain
9 secure immediately following any significant change in
10 status. Clear accountabilities are essential for the day to
11 day integrity of grid operations.

12 With respect to improvements in emergency
13 response, we need to establish a framework for a coordinated
14 and effective response to emergencies. A good framework
15 assigns each market participant specific roles in an
16 emergency plan. This coordinated effort assures the
17 capability to respond to a wide range of emergencies.

18 Operations staff require operating guides and
19 strategies that are robust and sufficiently wide in scope so
20 that they may apply to a wide range of post disturbance
21 configurations.

22 Continuous review and update of restoration plans
23 and procedures must be carried out. Various components of
24 the plan should be subjected to integrated testing so that
25 equipment critical to the restoration process is available

1 when called upon to act and performs as expected.

2 Effective emergency response requires capable and
3 trained personnel implementing actions supported by the
4 right processes, facilities and equipment. Pre-
5 identification of priority loads is critical for an orderly
6 restoration.

7 High standards for an uninterruptable power
8 supply requirements for equipment such as SKADA systems and
9 phones is essential. NERC certification is a minimum
10 requirement. Operators require an in-depth detailed
11 knowledge of their area and sound general knowledge of
12 surrounding areas.

13 As for drills and exercises, regular extensive
14 emergency preparedness base training is essential. Clear,
15 concise, controlled, orderly and methodical restoration
16 implementation helps prevent equipment damage, the
17 environment, protects the public, and ensures orderly load
18 restoration without recollapse.

19 Staff need to expect the unexpected. During
20 contingency events problems or barriers will occur. These
21 cannot be allowed to distract staff from their obligations
22 and priorities. To manage system emergencies effectively
23 during precontingency phase operators must operate the
24 system under studied and known conditions at all times. The
25 ability to derive limits and act within NERC approved title

1 lines is a key objective of emergency preparedness.

2 Tools must quickly enable operators to identify
3 the next critical contingency and assist in determining
4 actions required to remain secure. Multiple contingencies
5 occur regularly and cannot become a source of insecure
6 operation because of inadequate training tools or
7 procedures.

8 Of course, proper communication protocols must be
9 followed at all times.

10 With respect to authorities, the IMO is the RC,
11 the control area operator and also directs the operation of
12 the IMO controlled grid, which encompasses equipment 50 kV
13 or greater. Within the Electricity Act, the Ontario market
14 rules downstream agreements and manuals, individual entities
15 have the right to declare emergency conditions for safety
16 equipment and environmental protection.

17 The IMO has the local and global perspective and
18 has the authority, responsibility and obligation for
19 determining emergent conditions. We found this practice to
20 work exceptionally well.

21 Regardless of the makeup there needs to be clear
22 delineation in many areas. We firmly believe that NRC
23 should have the authority to declare emergencies within
24 their reliability area.

25 With respect to empowerment to prevent cascading

1 outages, to assist in this reinforcement specific stronger
2 language should be added to current NERC policies. As well,
3 specific directions should be sent to reliability
4 coordinators and their operating authorities to reaffirm
5 their obligation to the interconnections.

6 As for the availability of timely corrective
7 actions, we believe system resources are available for
8 response. The important factor is the reliability
9 coordinators being aware in detail of the full range of
10 options available to them including load shedding.

11 To illustrate that load shedding is an effective
12 emergency action, due to extreme events, Ontario has shed
13 firm load to remain within security limits and protect the
14 interconnections.

15 We take the view that over reliance on
16 transmission loading relief as a method to manage real time
17 limit violations is not prudent and can in fact lead to an
18 insecure operating state.

19 To illustrate this inadequacy, there have been
20 two instances in the last six years where portions of
21 Ontario have collapsed when external entities attempted to
22 call TLRs while overloads existed in their systems beyond
23 the NERC 30 minute standard.

24 On the question whether a full range of credible
25 contingencies is being assessed we stress that, in addition

1 to the exhaustive range of analysis, appropriate actions
2 must follow from the results. The most critical is read
3 preparation. It must be as soon as possible but no longer
4 than 30 minutes.

5 It is an obligation that rests with all the RCs
6 to act in the best interest of the interconnections at all
7 times. Satisfying total reserve requirements is not enough.
8 Reserves must be located appropriately to ensure associative
9 operating security limits can be met during activation.

10 As for improving communications, priority
11 communication (inaudible) are extremely useful. They also
12 need to be used by staff with the authority to act.
13 Consistent industry approved terminology and positive
14 confirmation helps prevent errors. Practice and training is
15 important but these points need to be included in everyday
16 processes in order for staff to be successful during
17 contingency events.

18 To maintain proper focus during contingency
19 events, we found that if rules and authorities are well
20 established and documented and overall expectations and
21 priorities are well understood by all parties, then
22 restoration incidents go much smoother with overall
23 objectives being met in a timely way with minimal adverse
24 effects.

25 Thank you.

1 MR. CAULEY: Okay thank you Kim and the second
2 speaker is Vicky Van Zandt of the Bonneville Power
3 Administration and also a team leader on the technical
4 investigation in the area of operations.

5 MS. VAN ZANDT: Thank you. Loud enough? Okay.

6 So the items that I'm going to speak to have come
7 out of the operations team largely and that's kind of
8 confirming because you will have heard a lot of these things
9 from Tim's comments and from the previous panel so we must
10 be zeroing in on the things that we need to do.

11 So question one, four items, assessment is
12 necessary and it needs to encompass more than seasonal
13 studies of typical conditions, more widespread determination
14 of simultaneous transfer limits taking into account
15 generating patterns, reactive requirements and voltage
16 collapse points. That's done in some places and not in all
17 places.

18 The second item, interactive simulation of load
19 probability but severe system conditions to recognize
20 disturbance characteristics and to practice response
21 techniques for both disturbance response and restoration.

22 So a lot of the entities involved in the
23 disturbance footprint had simulators but had not used them
24 in some time.

25 The third item, good visualization tools to help

1 with this recognition of disturbance characteristics and to
2 get immediate feedback on the effectiveness of operator
3 actions in real time without the power system effects taking
4 place but just assimilation of such.

5 And the fourth item, reinforcement of training
6 curriculum and testing to include simulators using actual as
7 well as potential disturbance scenarios, recognition of
8 disturbance precursors, mitigation of disturbance severity -
9 - include lessons from other areas and regions.

10 I think Dave's presentation earlier as we got
11 started, there were a lot of common themes in some of the
12 big disturbances that this continent has undergone and
13 hopefully we can eliminate having to learn them over again -
14 - common causes in disturbance because we've effectively
15 transferred the learnings from one area to the next.

16 On the second question related to tools, oops --
17 a few items here as well and the next panel will speak to
18 tools as well. So I have four items here too. The status in
19 alarm features. We need to develop a minimum fail safe
20 criterion for EMS systems to include back up provisions,
21 functional monitoring and assessment and transfer of control
22 to other authorities should the primary and back up systems
23 fail.

24 Perhaps the consideration of 24 x 7 IT system
25 monitoring of the EMS tools that's utilized in some places

1 and not in others, and this would be separate from the
2 system operations staff.

3 Second, thermal voltage collapse studies both
4 either real time or off line or on line -- I'm sorry, had it
5 right the first time -- real time or off line but, in any
6 case, with current system conditions.

7 Third, if cascading occurs for some contingencies
8 more quickly than an operator can reasonably respond, 30
9 minutes seems to be the break point, it has to have
10 automatic controls in place to act as a safety net. So
11 we'll hear some more about that in the system protection and
12 control panel.

13 Fourth is just a note -- sort of an epiphany from
14 me as the investigation is going forward -- is all the
15 studies in the world and the assessment and the contingency
16 planning, all of that, is regardless of the care taken in
17 doing that with good rigor and determining what the current
18 status and what you think the vulnerabilities of the power
19 system are, they don't mean anything if they are obstacles
20 in the transmission rights of way particularly in the
21 summertime.

22 Transmission lines that trip out before overload
23 pretty much render that assessment invalid.

24 Okay, the third question -- I have six items
25 here. Between system items and reliability coordinators,

1 who has authority and responsibility to do what? It's
2 pretty much the feeling of the group that control area
3 operators are the first line of reliability defense and
4 should be the first to declare an emergency if the tools in
5 their assessment and their visibility is working well,
6 should be the entity to take action.

7 Control areas need to raise the alarm when
8 they're in trouble so maybe some communication protocol or
9 something other than just dialing the phone, maybe a red
10 button that opens communication lines so a reliability
11 coordinator might be hearing what's going on in the control
12 center would be a possible consideration.

13 A third item, if they don't either see that there
14 is an emergency or fail to raise the alarm, reliability
15 coordinators have to have sufficient authority and means to
16 carry out actions to preserve reliability and that needs to
17 be confirmed with regular and rigorous audits.

18 Fourth, if the RC sees a disturbance in the
19 making, they need the authority to declare an emergency and
20 order specific relief and conversely system operators need
21 to comply -- if they disagree, comply first then argue about
22 it later.

23 Fifth, the reliability coordinator needs enough
24 visibility with enough granularity to assess system problems
25 and determine appropriate responses to shortstop a potential

1 cascading problem.

2 If it's at too high a level or too aggregate a
3 level then their ability to render aid if the primary line
4 of defense doesn't work is limited.

5 Last for this question, the reliability
6 coordinator needs tools sufficient to determine simultaneous
7 limitations on transmission paths. That's done in some
8 places and not in others. And it needs to include thermal,
9 voltage and transience stability if that's appropriate.

10 In some areas state estimation and contingency
11 analysis is necessary but it's not sufficient. If a
12 contingency analysis says you have a problem, you do. If it
13 says you don't have a problem you still might. It does not
14 provide transience stability limitations.

15 The fourth question, two items -- the authority
16 to take actions and responsibility to take those actions to
17 prevent a cascading outage. Industry really needs to
18 support operators exercising that authority. It is clear in
19 the NERC policies and in operating procedures, standing
20 orders and control centers that operators have that
21 authority and they have that responsibility but their job,
22 day in and day out, is to keep the lights on, so we need to
23 reinforce that. And there have been some instances where
24 operators have not been congratulated for shedding loads to
25 prevent a disturbance because if the disturbance is

1 prevented somebody's load was lost and the "bad" thing
2 didn't happen, so there's a lot of second-guessing.

3 Operators need to have and know where their
4 collapse points are voltage wise. Assessment tools need to
5 include wide area view of current conditions and warning of
6 contingency problems beyond that of simultaneous thermal
7 limits of transmission circuits.

8 The fifth question really reflects what Kim's
9 comments were -- are there adequate resources available to
10 respond? Not always. TLR-6 is load shedding. It must be
11 possible to shed load very quickly if you're going to use
12 that tool, if you've already got an overloaded transmission
13 system then cutting schedules is not going to perhaps be in
14 time. It will likely not be in time.

15 Second item, we need a redispatch stack of
16 options to relieve transmission quickly if there are
17 resources on either side of a loaded path or a path in
18 trouble. Schedule reductions are meant for contingency
19 relief proactively and in anticipation of a possible
20 contingency. They are not for emergency action, so we need
21 to beef up those tools in some instances.

22 The sixth question, three items, standard
23 protocols and terminology -- in reviewing a lot of the
24 transcripts there were some time used in getting to the
25 point, if you will -- so standard protocols, getting right

1 to the point and using common terms, would be helpful.

2 Second item, emergency drills, simulation with
3 both the control area or transmission operators and the
4 reliability coordinator in play -- would be good.

5 The third item, it's necessary to see into each
6 others' systems far enough to be effective. Agreement at
7 the scenes about what facilities would be discussed about
8 relevant control area operators and reliability
9 coordinators, which ones matter -- needs to go far enough
10 into the overlapping control areas and footprints so that
11 those facilities would have an impact on their neighbor,
12 they need to be included and discussed.

13 And the last question, recommendations to ensure
14 operators' focus on reliability -- three items. Dedicated
15 personnel assessing the status of the system, possibly
16 leading the commercial arrangements separate from operation.

17 The second item, communicate with each other
18 within and between control centers with some evidence of
19 time trying to assess a problem before you raise the alarm
20 to the neighboring control area, their own reliability
21 coordinator or neighboring ones.

22 Finally, the last item, protocols prioritizing
23 the attention of at least one control center dispatcher to
24 determine the course of action if you're in a disturbance
25 and it's progressing. And delegate commercial schedules,

1 hourly commercial schedules or routine phone calls, to
2 others.

3 So I will stop there and look forward to
4 questions.

5 MR. CAULEY: Okay thank you and we'll start with
6 our again our distinguished panel of investigators. Do you
7 have any questions or comments?

8 MR. MEYER: I'd like to ask the panel and the
9 audience also about best practices with respect to training
10 particularly with respect to identification of emergencies
11 and responding to emergency conditions and I am interested
12 in the possibility of, I recognize that the training of this
13 kind can be a burden for some companies and that might cause
14 them to question do they have a way to really meet some of
15 the standards, the high standards of performance, that might
16 be seen elsewhere.

17 But I think some of those problems could be
18 overcome through the establishment of more centralized
19 training programs and facilities that would be widely used
20 by companies or organizations across broader areas.

21 I realize you would have to fine tune some of
22 these training programs to meet regional conditions and
23 regional needs, but I think that's a problem that could be
24 dealt with.

25 So I welcome some feedback on those themes.

1 MR. CAULEY: Okay anything from the audience?

2 MR. HILT: Gerry I have a couple of questions.

3 MR. CAULEY: All right Dave sorry. I didn't see
4 your hand go up there.

5 MR. HILT: That's all right. I wasn't fast
6 enough at grabbing the mike. That's quite all right.

7 From the panelist as well as the audience, one of
8 the things that was mentioned here was load shedding is a
9 tool and has to be a tool that's available to the operator
10 to preserve the system. However it appears to be
11 politically unacceptable and we are not doing an adequate
12 job of I guess congratulating or I guess promoting "the
13 right thing" being done by the operators.

14 I would be interested in hearing what you think
15 we can do about that in terms of changing that political
16 perception that there comes a time to preserve the system
17 that we need to shed load. What types of recommendations we
18 might hear from that would be something of interest to me at
19 least as to how we, not necessarily promote load shedding
20 but promote it as there is time to do it and has to be done
21 to preserve the system, otherwise putting it at a very large
22 risk as it was on August 14.

23 The second thing I heard was talk about location
24 of reserves and I know we're going to get into that a little
25 more in the planning and design but I'd certainly be

1 interested in hearing some comments on that and concepts of
2 the redispatch stack, certainly that may have some impacts
3 on the development of wide area transfer limits and
4 simultaneous transfer limits if there's a requirement for a
5 certain amount of reserves to be provided in a given area.

6 And that certainly may be necessary but I would
7 be interested in any comments or recommendations on those
8 areas.

9 MR. CAULEY: Okay from the floor here. Let's
10 see, Ray in the back and then we'll come back toward the
11 front here.

12 MR. KIRCHOW: Ray Kirchow from DTE Energy -- does
13 that work?

14 MR. CAULEY: Not any more, no.

15 MR. KIRCHOW: I'm with International Transmission
16 Company which are the old assets of Detroit Edison and the
17 question is related to something that Dave was saying, are
18 you considering changes to Policy 9 in terms of the
19 emergency procedures part of it such as load shedding to
20 maybe ease the operators' burden on calling it and not being
21 condemned for doing it? I would recommend something like
22 that.

23 I mean, that's one way of handling it, putting it
24 right in Policy 9, and actually Policy 9 itself giving it a
25 little more teeth -- you know, there's a lot of criticism of

1 TLR procedure being slow -- well, there's probably ways to
2 jazz it up a little bit. I'm not quite sure, I don't have
3 any specific recommendations right now but there's a lot of
4 complaints about it and I think one of the first things that
5 could happen that we'd like to see is the tool that
6 implements it, the IDC be improved, make it more of a real
7 time, speedy tool, I'll call it.

8 For example, the SBX was not updated on August 14
9 so it would be nice to have that to kind of force people to
10 input topology changes on a real time basis and the other
11 thing would be to actually input dispatches into the IDC.

12 When you do this, right now, the IDC mimics
13 dispatches but if you actually input the real time dispatch
14 wouldn't have to mimic it any more. It could calculate
15 relief from the real time system.

16 This is not going to be free and right now NERC
17 budget pays for this so somehow I think there should be an
18 incentive to make that a little bit better.

19 MR. CAULEY: Okay Scott?

20 MR. MOORE: Scott Moore, AEP. I have two
21 responses to both Dave Meyer and Dave Hilt. The first one
22 I'd like to address is the training issue. We work rotating
23 shifts with our system operators and our reliability
24 coordinators and quite often, and actually I see a dichotomy
25 between the non profit organizations who basically can pass

1 on all their cost to the members, do an extremely good job
2 of making sure that they have adequate numbers of shifts to
3 allow for adequate training.

4 As I look across the industry and at AEP as well
5 where we're not non profit organizations, we don't have the
6 ability to pass on costs to our members, that we take a hard
7 look at the number of operators that we have and, over the
8 course of the last 10 - 15 years, I have noticed within the
9 industry and talking to people, that we have down sized
10 quite a bit of our operations staff. We've done that at the
11 same time that our staff has gotten older and maybe
12 available for more vacation time.

13 And quite often, when we staff up our shifts on
14 what we call a "relief week," that relief week is designed
15 to allow for training and to relieve brother operators who
16 are on vacation who are gone, who have gone to training or
17 are sick.

18 And unfortunately when you look at the way that a
19 lot of shifts are now designed, and you have to cover the
20 basis of everyone on relief, that there's not a whole lot of
21 time left for training.

22 So there's two pieces. One is the amount of time
23 for training and the second is the type of training that
24 you're training on, that Mr. Meyer addressed.

25 So those are the two issues and I think that NERC

1 needs to look at and the personnel committee of NERC need to
2 look at what are the minimum amount of training days
3 required for certification? We have, as we go forward with
4 continuing education program or testing program, it's really
5 not defined although we're looking at a certain number of
6 hours, and I'm not sure that's really going to meet what's
7 really needed. It may meet what's needed for certification
8 but it's not what's needed to have a good, properly trained
9 operator.

10 And I think if you look at other industries, if
11 you look at the nuclear industry, there is a minimum
12 requirement of training dates and I think that NERC needs to
13 look at that in terms of our system operators, those who are
14 dealing with the reliability function.

15 So it's both the amount of training you get and
16 what you get trained in, both locally and from a wide area
17 basis in emergency operations.

18 The other thing I would like to address is the
19 load shedding issue and I've mentioned this to others and
20 I've talked to Vicky -- operators, their frame of mind and
21 what they're trained to do, is keep the lights on.

22 Now one of the tools in order to keep the lights
23 on is to turn them off.

24 But they're reluctant to do that -- and it's not
25 only just politically reluctant for managers to do it or for

1 regions to do it, and who's going to pay for it -- but the
2 operator sitting at the desk is even reluctant because he's
3 been trained to keep the lights on.

4 So what we need to look at and what we have in
5 place already is under-frequency load shedding. You know,
6 that last ditch effort to keep the system there. But what
7 we don't have is under voltage load shedding where our
8 special protection schemes that is looking at the critical
9 flow gates that, if you do get the contingency loading, that
10 you could have a special protection scheme that, if the
11 proper thing to do is to shed load regardless of voltage,
12 regardless of frequency, but if the loading on a particular
13 flow gate gets to a point and normally this happens fast
14 because of a contingency, that you have special protection
15 schemes to remove the load and preserve the system.

16 Now I think this would be a backstop -- but the
17 operator still has to be trained to take proper action as
18 you are looking forward. But if he doesn't or if he's
19 unable to because of the time to take that action, then you
20 need to have better use of special protection schemes that
21 are automatic and that are armed and are you know under
22 voltage relaying that can take care of that.

23 So I think those two issues need to be looked at
24 very carefully and critically.

25 MR. CAULEY: Okay. I'm assuming you guys are

1 okay unless I hear from you -- okay, go ahead.

2 MR. WARREN: I was just curious if you wanted us
3 to respond.

4 MR. CAULEY: Just give me a wave any time.

5 MR. WARREN: Just a wave. Let me know if I jump
6 around a little too much.

7 But on the issue of training, there was a phrase
8 of "being a burden" -- but that's actually an investment
9 that we take quite seriously and I think in the Northeast
10 the time spent on training for the RCs is in the
11 neighborhood of 15 to 20 percent of their time and we have
12 dedicated trainers. We have regional restoration training
13 drills, we have in-house training drills but they're all
14 market participants and such and we find them quite
15 effective. And there's some use of simulators.

16 But what we've found actually is even more
17 beneficial lately in emergency preparedness training drills,
18 we use our normal operational center for the actual drills
19 themselves and we operate the systems and such, from the
20 back up centers during that time and we go top to bottom
21 with our training and exercises and such and we involve more
22 than just the operational staff, the people that have to
23 support them, we found that to be very, very beneficial,
24 obviously during August 14 and 15.

25 As far as load shedding, I'm disappointed that we

1 have to promote it as an operational tool. It's already in
2 Policy 9. It's the jobs of those that supervise the
3 operation staff to ensure they're properly prepared. It's
4 unfortunate that people look at it with some negative
5 connotations but it is a very effective tool to relieve an
6 operating limit violation.

7 And as far as the locations of reserve issues go,
8 throughout the Northeast we have some very detailed policies
9 and basically when we tackle any given day, we've already
10 been well prepared through our next day security analysis
11 and such in the information exchange with our neighbors
12 about what elements are out of service and we look at the
13 removal of all elements to ensure that other than connected
14 load we can move reserves around to satisfy any expected
15 contingencies. And that's -- we term that more "area
16 reserve" than just system reserve.

17 We're not only looking at just megawatt transfers
18 but also reactive in such in being able to react timely to
19 any contingency event.

20 So then when we drill down frankly through area
21 reserve and the term called "repreparation" -- that's an
22 operating doctrine, if you will, that instills in the
23 operator's mind that it is not appropriate to sit over an
24 operating security limit violation and his actions to
25 relieve that constraint should be as soon as possible. He

1 doesn't have the luxury of time normally in his favor.

2 That's it.

3 MR. CAULEY: Vicky?

4 MS. VAN ZANDT: Gerry? On best practices, I
5 think there's probably not anything better than simulation
6 of a disturbance you've lived through. That would certainly
7 have the operators' attention especially if the disturbance
8 had a bad effect.

9 Out in the West we have simulated the August 10,
10 1996, outage, what operator actions could have prevented how
11 that eventually came apart. So simulation is kind of hard
12 to put together especially if it's interactive and includes
13 operator actions, we have to anticipate that and in a wide
14 variety of those in order to do it but I don't think there's
15 a substitute for it.

16 It's also possible to use other simulators.
17 You'd certainly probably want to practice on scenarios that
18 were in your operating area but other disturbances as well.

19 We've gone to hours out to for folks who wanted
20 to train on actual events or potential disturbances so
21 perhaps if entities didn't want to develop their own, there
22 are others that can be used.

23 Load shedding reinforcement -- I have operational
24 responsibility for a pretty good size grid. We have two
25 control centers and they can fully back each other up. I

1 recently, since the interim report was out, went to visit
2 each of the control centers and did a presentation about the
3 facts and issues of the August 14 scenario.

4 There was -- I've never had quite that level of
5 attention from the system dispatchers before. And we've
6 revised our dispatcher standing orders to include -- you not
7 only have the authority if, in your judgment, you need to
8 shed load in order to preserve the system, I want you to do
9 it and I will stand right next to you when the inevitable
10 second-guessing occurs.

11 So I think reinforcement of that, well,
12 unfortunate and I agree with Scott that it's counter to what
13 system dispatchers are trying to do -- they keep the lights
14 on so they hate to turn even a single one off. But
15 sometimes it's necessary.

16 And then finally I also agree with Scott in
17 having some safety nets that are automatic. A wider use of
18 under voltage load shedding.

19 MR. CAULEY: Okay. I think you, the gentleman
20 over here, you were next?

21 MR. DELAY: My name's Frank Delay. I'm retired.
22 In my youth I worked for ConEdison and I'm old enough to
23 have remembered the post analysis of the 1965 blackout and
24 the 1977 blackout, the '77 blackout I was senior enough that
25 I had a fair amount of responsibility in conducting the

1 analysis of it.

2 The first thing that strikes me in listening to
3 this panel and the prior panel is how many issues overlap.
4 The same issues -- '65, '77, and I looked at a number of
5 blackouts subsequent to that -- same issues.

6 A point I think has to be addressed in the longer
7 strategic terms is the fact that what you tend to lose is
8 what I call "institutional memory." At the time of the 1977
9 ConEd blackout people were running around trying to remember
10 what we agreed to do in 1965. If I look back now at the
11 people who were in management positions in 1977 at ConEd,
12 we're all retired if not gone even further beyond that.

13 (Laughter.)

14 MR. DELAY: I think one of the things you have to
15 do is put together some sort of a "lessons learned list" and
16 it's not a short list. It is a long list. In sitting here
17 today I said, "What do I want to comment on?"

18 I probably would have been up to about 100 things
19 but I think you have to put these lists together.

20 Now trying to respond to the issues by writing
21 more standards is nice but I think you have to recognize
22 there's another issue and that's the quality of the response
23 to the standards. You can say "we'll have metering."

24 But then you can look into a whole spectrum of
25 how good is the metering? Provide more data to the

1 operators? The operators are human beings and can only
2 assimilate so much. How do you deal with that?

3 I think you have to have some measure of good
4 design, good practice -- we've heard the gentleman refer to
5 "a good practice installing computer programs." Well, I
6 think that applies to almost everything you're going to do.
7 It maybe is cross fertilization, one company versus another,
8 but I think you have to have something in place for that.

9 A third thing I think has to be addressed, and
10 what I've noticed in the past in post-mortems on blackouts,
11 they tend to involve planners and operators. But I never,
12 hardly ever, hear design engineers get involved and I know
13 when we looked at the ConEd blackout we really dug into some
14 of the engineering issues.

15 There was an example I use on restoration. One
16 of the problems we had was trying to restore quickly was we
17 wanted to change transformer path on distribution
18 transformers.

19 Well, it turned out that the pack changing
20 mechanism was located from a voltage source in the low side
21 of the transformers so you'd actually have to energize the
22 transformer to get the low site energized before you can do
23 the pack changer.

24 A simple, dumb thing but it impacted restoration
25 and the problem with the design engineer that had never been

1 sensitized to the criticality of the restoration issue.

2 Now separately, a theme that I've heard run
3 through a number of people today was the availability of
4 resources. Again it's very nice to say you want to do
5 things but I think you have to explicitly consider the
6 availability of the personnel to do them and the financial
7 resources to them.

8 I don't know but I suspect that, given the
9 financial crunches that had gone on in the industry over the
10 last few years, it is very, very easy to cut back on
11 training, right of way maintenance, and you can go on and
12 make a laundry list of things, and this is sort of like
13 "well we don't talk about it because my boss won't give me
14 the money" but I think it's critical that these financing
15 issues and personnel issues be addressed.

16 Now finally on more technical issues, in reading
17 the report, one major thing that struck me was the
18 "omittance," if you would, of any discussion of restoration.

19 And by any definition that we look at when we
20 talk about the severity of a blackout it's duration is part
21 of that equation. The number of people involved is part of
22 it, but duration is part of it.

23 Look at your distribution indicia, the ones that
24 are used by distribution planning duration. I urge that a
25 thorough review of the restoration process be undertaken,

1 again, to learn lessons -- how can it be made quicker? I'll
2 leave it at that.

3 MR. MEYERS: Gerry, let me respond to this, the
4 question about restoration.

5 In writing the Interim Report, we looked very
6 closely at our mandate from the Task Force, which was the
7 mandate to the task force, which was to identify the causes
8 of the August 14 blackout and devise recommendations.

9 It did not mention restoration in our view.

10 That does not mean restoration isn't an important
11 issue. We think it is a very important issue and we are
12 going to conduct an independent parallel analysis and we
13 will report on that in due course.

14 MR. CAULEY: Right behind Scott there?

15 MR. THOMPSON: I'm Bill Thompson from Dominion.

16 I'd like to make a comment about load shedding
17 and I agree with everything that's been said but I want to
18 try to take it one step further because I think we all agree
19 that the reliability coordinator has to have the authority
20 to order a load shed. I don't hear a lot of disagreement
21 with that.

22 But if that order is given to a bunch of control
23 areas who don't have the capability to automatically go into
24 their SKADA system and shed load it's probably a worthless
25 command.

1 And I think one thing we need in the industry is
2 a standard that NERC puts out that we all, as transmission
3 owners, I guess, or distribution companies -- I'm not sure
4 where that responsibility lies yet.

5 But let's have a standard that says "you're going
6 to have this capability to shed load automatically if it's
7 ordered by the reliability coordinator. That's one thing
8 that I strongly think that we need as an industry.

9 I would be willing to participate in that and at
10 Dominion we have a very good load shed program. I hope I
11 never have to use it again. I used in in 1994 along with
12 PJM, my friend over here Mike Kormos and his staff, and some
13 comments were made about the political aspects of shed load
14 and I have to agree with all that. That's certainly the
15 last resort that any operator wants to use.

16 But let's face it, that is better than the
17 blackout that could happen if we don't use that resource.

18 MR. CAULEY: Thanks, Bill.

19 Way in the back, is that Meyer again? Yes.

20 MR. SASSON: Thank you Gerry.

21 As I'm hearing the comments about load shedding I
22 thought I would add my comments on the same issue. And I
23 think the hierarchical, the way I would like to look at it,
24 and the way we look at it in New York, is that first of all
25 we do have mandatory rules. Those rules have developed over

1 many, many years of experience. Some came out of orders
2 from our public service commission out of the '77 blackout
3 for example that, in regards to having means to shed load --
4 but the important thing is that those mandatory rules have
5 to be translated into procedures, operating procedures and
6 the operating procedures, as we have all said, have to
7 reduce to operator training so they become totally
8 knowledgeable about operating procedures.

9 Operating procedures not only impact transmission
10 owners but also as it was at the New York power pool and now
11 is at the New York ISO -- so when you put all that together,
12 none of the issues that we have been hearing really come to
13 play in New York.

14 If the New York ISO orders the ConEdison operator
15 to shed some load, the ConEd operator will shed load --
16 he'll discuss it later but will shed load now.

17 If there is a rule saying a line loading cannot
18 exceed a certain emergency level for more than five minutes
19 and if the operator cannot through all the normal things
20 that he can do in five minutes, get below that level, the
21 operator must shed load to get below that level because
22 that's how you're going to protect the system. You might
23 lose a little portion but you're protecting the larger
24 portion.

25 So those are rules and procedures and should not

1 be that the operator makes a judgment at that point he has
2 five minutes -- five minutes are up -- he needs to shed load
3 if the loading is still above that very high emergency
4 level.

5 So mandatory rules translated into procedures
6 translated into clear authority, hierarchical authority --
7 and I know I'm repeating what panelists have said -- but
8 that works and that's what we have in New York.

9 Thank you. I thought I'd mention it.

10 MR. CAULEY: Okay, thank you Meyer.

11 Bill Middlestadt from Bonneville Power
12 Administration?

13 MR. MIDDLESTADT: Thank you.

14 As the system has operated closer to its limits
15 the challenge will be greater for the operators for some of
16 these multi contingency outages and they may still have the
17 ability to handle the more routine outages. But the
18 challenge will be greater for the multiple contingency
19 outages.

20 I think it would be useful to do an analysis and
21 take a look at the coverage that we have, the kind of
22 coverage that we can expect our operators to provide and
23 then to also understand areas where we may need to consider
24 filling in some of the holes that are there.

25 And I haven't seen a holistic look at the whole

1 protection issue of what's covered? Can we expect to be
2 covered by the operators and what do we need to cover in
3 other ways?

4 The things we can do for the operators would be
5 to develop tools to add capabilities that would assist them
6 and provide them more information on actions that they can
7 take. And then secondly going beyond that, the next step
8 would be to have tools that would not only provide guidance
9 for them but once the operators were comfortable with them,
10 would actually allow the tools to initiate some actions.

11 And then finally we have special protection
12 schemes that are needed when the time required is so short
13 that the operator even with the best alarms or the best
14 information is not able to take the action -- then we have
15 to have special protection schemes.

16 And then finally beyond that, safety nets.

17 So anyway I just encourage taking a look at it
18 from a holistic standpoint in terms of what's reasonable for
19 the operators to do, how we can enhance that and then what
20 do we need to go beyond that?

21 MR. CAULEY: Thank you. Any responses --

22 (no response)

23 -- okay, Kim?

24 MR. WARNER: I just want -- I agree with many of
25 the things that were said here.

1 What we've found in our area to be extremely
2 beneficial is, when we supply operators with information we
3 supply more than just the basics. We don't just tell them
4 "here's the limit and stay underneath it" type of thing.

5 They're aware of what type of limit it is.
6 They're aware of the studies and the information behind it
7 and they know what the critical contingencies are.

8 And that's not just for all the elements in
9 service state. They're aware of what critical components
10 can affect that limit and what options are available to them
11 to try to mitigate any operating concern.

12 And they're given enough information that they
13 can, during the wee hours of the morning when some of the
14 support staff and such aren't normally there, they can
15 analyze multiple non critical elements at a service and
16 determine a critical operating state themselves. And they
17 can determine their own transfer limits as necessary and yes
18 there are calls that are going out to the operating
19 engineering staff to help revise some of these limits and
20 some of the limits that they come up with may be
21 conservative in nature but they will operate to those
22 limits.

23 And that's quite an undertaking to try to bring
24 staff to that level but we've found it's very effective and
25 it also engages the operations people from both the planning

1 side and the operations side in numerous discussions.

2 That is very helpful when the engineering staff
3 is coming up with new operating parameters that the staff
4 will have to manage.

5 It's also very beneficial as we get ready for
6 seasonal type of activity like winter, the winter peaks or
7 the summer peaks that we have. They're engaged months and
8 months before.

9 And as we see things in real time we bring in the
10 engineering staffs and such so that they too can see the
11 relationship between one resource and limit and between
12 different limits and how they're reacting and to make sure
13 that the studied parameters that they are using bear a very
14 close relationship to real time.

15 And we've found that those types of opportunities
16 when exercised have been very helpful for both entities.

17 Thank you.

18 MR. CAULEY: Thank you.

19 Terry Mitchell? You are the last comment for
20 this session.

21 MR. MITCHELL: Yes. I agree with all the
22 comments on load --

23 MR. CAULEY: Terry, Terry --

24 PARTICIPANT: Terry (inaudible) from Excel
25 Energy. I agree with all the comments on load shedding.

1 That's one of the most difficult control room decisions to
2 make but let's not forget about the other side of the
3 equation, too, as emergency generation redispatch. That's
4 part of TLI level six.

5 Also, even though you may not find a set of
6 incrementing and decrementing generators right available to
7 you, decrementing a unit on the correct side of the problem
8 area can be beneficial while you search for some unit to
9 increment.

10 So let's not forget about that as a tool for the
11 coordinators also.

12 But we also keep talking about shedding load and
13 response to a problem. I want to just go back to June 25 of
14 '98 that's one of the events that's footnoted in the report
15 and the part of the IMO that stayed up this time we blacked
16 out from an event in the MAP region and everybody's all
17 accustomed to low voltage and low frequency -- that event,
18 North Dakota went to 62 Hertz -- and shedding load is the
19 wrong response.

20 So also from an operator perspective, you also
21 have to talk about the other side of the equation, high
22 voltage and high frequency and not have your system go down
23 for that type of event.

24 MR. CAULEY: Okay, Ed Suartz, NPCC?

25 MR. SUARTZ: Thanks Gerry.

1 To pick up on the discussion, this is an
2 emergency response panel and we have discussed a lot about
3 shedding load.

4 But I'd like to take us back to how Kim started
5 this off in that prevention is actually the best emergency
6 response. And one of the blackouts that isn't referenced in
7 the report is a blackout that didn't happen because Ontario
8 took the emergency response, put itself in a super secure
9 situation and survived the loss of an entire generating
10 station, which our study said they could not have survived.

11 Their operators took the action early-early on to
12 put the system in a more secure state.

13 Fundamental things we're talking about here are
14 operating the system within its known limits. If in an
15 unanalyzed state, we've talked about the time to respond.
16 That time shrinks down to immediate.

17 We do not have the luxury of 30 minutes to get
18 the system back into a known state. Those actions need to
19 be taken immediately. The operator needs to be trained and
20 needs to have the tools available up to and including load
21 shedding to get back within known limits.

22 Those limits need to reflect actual capabilities.
23 We talk about right of way clearance, right of way
24 maintenance. The transmission limit needs to reflect the
25 fact that right of way clearing hasn't been done in the last

1 14 years.

2 Then you're operating a system within a known
3 state. If in fact you've got right of way that hasn't been
4 maintained yet limits it as soon as they are, then the
5 operator is not being given information about the system
6 that he has in front of him.

7 Also in terms of utilization of PLRs in TLR three
8 for an overloaded line is the incorrect response and we need
9 to address that.

10 Just to wrap up, as an example, with an NPCC
11 criterion, we do have a section of the criteria operation
12 under high risk conditions. We need to consider addressing
13 that as a NERC standard.

14 MR. CAULEY: Okay, thank you.

15 Tom? Tom Rusnor?

16 MR. RUSNOR: Am I on? Thanks Gerry.

17 There are so many great comments here that I am
18 not sure where I am going to begin but I would just like to
19 say a couple of things -- Scott's mention of differences
20 between private entities, private profit making, and public
21 -- is perfectly valid.

22 That is not to say that the publicly owned
23 entities did not have any financial constraints. Over the
24 years I have been a system planner for 25 years with
25 accountability for taking capital projects upstairs to get

1 approval for them for often hundreds of millions of dollars
2 a year.

3 You know, I have never been refused a capital
4 project when I presented a good, valid case for reliability.
5 That meant doing a lot of homework, a lot of studies, often
6 convincing senior management who didn't have a clue about
7 what a stability analysis is -- so you've got to talk to
8 their language and you've got to be convincing.

9 I'll repeat -- I've never been refused a capital
10 project for reliability.

11 The other area I've never been refused a capital
12 project in is when I could demonstrate that it was
13 economical over the long term for a power system and
14 skimping on a few operators is just wrong, absolutely the
15 wrong area to skimp on.

16 Skimping on maintenance is also, like Vince said,
17 is the easiest area to cut costs in. Senior management in
18 its wisdom assigned me from transmission to look after our
19 Ontario distribution system which at the time had something
20 like 110,000 kilometers of line.

21 Whenever a request came down to cut cost by five
22 percent, guess where it got cut? Maintenance, forestry --
23 that's the easy place. I had an analysis done of the
24 forestry work and I thought they were spending too much
25 money, about \$27 million a year.

1 After the analysis was done it turned out that we
2 would have to spend double that amount over a five year
3 period just to catch up.

4 So was that a worthwhile thing? I think
5 management took the easy way out saying "we need to cut five
6 percent, okay, we'll cut five percent."

7 My response always to that kind of a thing was,
8 "I don't believe it and I'm going to prove that that's the
9 wrong action."

10 So you can't take the easy way out by saying "I
11 have to do it." Management says I've got to do it.
12 Ultimately if they insist you're going to have to do it but
13 not without a fight. And that goes for operating, for
14 maintenance, for staffing, for whatever the resources are,
15 it's our responsibility to convince management where the
16 money should actually be spent.

17 The other area is in load shedding and I guess I
18 must confess I have a rather poor memory so I asked Mike
19 Penstone in the audience to give me a list of all the places
20 in Ontario where we had automatic load shedding installed.

21 And so I think Mike gave us about four pages
22 listing the areas where we had automatic under voltage load
23 shedding installed and I guess I was a bit chagrined because
24 I specified a significant number of those back in the '70s
25 and '80s.

1 And they're automatic. The operator arms it when
2 he's anticipating a particular contingency but he doesn't
3 have to take further action in most of those cases. Some of
4 them are clearly manual and on the spot.

5 So you can blame the planner for putting it in
6 place if the operator needs the excuse to arm the thing.

7 Those are my comments. Thank you.

8 MR. CAULEY: Okay we're going to take -- this is
9 not a real break. We're going to seat panel C and we're
10 going to get through at least the presentations of panel C
11 before we break for lunch. That will give us some breathing
12 room this afternoon and get us all on our merry way before
13 too late this afternoon.

14 So if I could get panel C up here? I'm still
15 missing two slides, presentations from panel C, and we will
16 take a five minute break in place and start at 11:25 a.m.
17 with the panel C presentations.

18 (A brief recess was taken.)

19 (Back on the record.)

20 MR. CAULEY: Alison Silverstein has shown up and
21 -- do you have any remarks, Alison? Just a hello? After
22 later? Okay.

23 Go ahead and grab your seats please?

24 Panel C is looking at tools we provide operators
25 and reliability coordinators. Obviously alarm systems,

1 state estimation, visibility in system, map boards, those
2 kinds of things, were issues on August 14 and we'll hear
3 some ideas and recommendations from the panelists on how to
4 address some of those issues.

5 And if I could get somebody to chase some of the
6 people in from outside that would be a help.

7 We'll go ahead and start with Dave Zwergel from
8 the Midwest ISO.

9 MR. ZWERGEL: Good morning. I'm David Zwergel
10 from the Midwest ISO and I'd just like to make a couple open
11 or introductory comments that I would like the tone and
12 proactive forward thinking of the panel members and
13 participants of the improvements that we're talking about
14 for the industry.

15 Just like many of you are looking at their
16 systems, MISO is looking at ours -- in several areas and
17 tools, training, staffing, our processes, and also in what
18 we're calling our "reliability charter" to go back and look
19 at, build on, a functional model and, as we start our market
20 operations, make sure everybody knows who's responsible for
21 what.

22 So we're working with our members right now, our
23 transmission owners, on a comprehensive reliability
24 enhancement plan along with working with FERC staff at MISO,
25 the Department of Energy on some forward looking things, and

1 looking to implement the best practices that others have
2 talked about here.

3 We have arrangements to go and visit some of the
4 industry experts in simulator training and we have Steve Lee
5 from AFRE coming into our shop tomorrow to talk about some
6 of the tools.

7 So I just want to congratulate everybody on the
8 tone and what they're talking about for these tools.

9 But for our area I can give you an update on some
10 of the things we're doing and what we have in place now.

11 First of all policy nine talks about monitoring
12 key facilities and we were doing that and we continue to do
13 that and I just want to note it may not be adequate although
14 the controllers are required to monitor everything and the
15 reliability coordinators are required to have some level of
16 monitoring.

17 I'd like to discuss standards, having standards
18 of what you need to monitor to have the proper -- so these
19 policy decisions and clarifications must be made to
20 determine what the reliability coordinators are truly
21 supposed to do to ensure reliable operations.

22 I know that NERC operating reliability cut
23 subcommittee is looking at that, making recommendations and
24 clarifications to the operating committee and that will take
25 some of the recommendations out of this workshop to help

1 with that as well.

2 Observability -- the question of what is the
3 criterion for observability? Well, clearly to have good
4 observability, monitoring of all -- contingency analysis of
5 all facilities of 180 and above would be required, any
6 significant size generators and just trying to start out on
7 a proxy for what these standards might be, say 100 megawatt
8 and above.

9 Contingency analysis of all neighboring
10 facilities that would impact the reliability would be
11 required. I think more work needs to be done in this area
12 as far as describing what needs to be done. Too many places
13 in the policy there are vague words of -- "key facilities"
14 or "adequate" -- without really describing what needs to be
15 done.

16 I think that will go a long way of the criteria,
17 what needs to be done here. The standards for this
18 monitoring contingency analysis must be developed and
19 implemented consistently across North America.

20 I agree with the comments that there are some
21 regional differences, but there should be some strong
22 minimum standards and we are in the process of implementing
23 this level of observability. Our local transmission
24 operators are required to do their job. That is still
25 needed and as some of the other panel members have described

1 -- but we are going beyond what's required and we'd like to
2 see the standards go there as well.

3 The next question was on map boards and back up
4 tools. We have in place a dynamic map board today at MISO
5 and I have a couple of views of it to show you.

6 But dynamic map boards are required for
7 reliability coordinators to get the big picture. I think it
8 is important for us to say what the "big picture" is and not
9 just to use those words but define what we mean.

10 Map boards to facilitate quick analysis and
11 decision making of the system conditions, which is essential
12 for emergency response in rapidly changing conditions. So
13 you could see graphically we might be getting a lot of data,
14 SKADA data, contingency analyses, alarms, all kinds of
15 things coming in, but it helps to get the visualization of
16 what's going on as well.

17 We have implemented a dynamic map board showing
18 all 230 kV and above facilities in our footprint. We have
19 that in our Carmel facility. We also have map board
20 capabilities in our St. Paul facility.

21 We're implementing different views from this --
22 Gerry, if you could just go to the next one, I could explain
23 better.

24 (Slide.)

25 This is just one piece of it right now -- we have

1 in the Carmel facility two ten foot by twenty foot long
2 displays of the transmission system and it's the 230 kV and
3 above. It has alarming capabilities as far as high and low
4 voltages show up on it and we have indicators -- any forced
5 outages turn dashed and you'll see blinking of the stations
6 if it's forced outages -- maintenance outages are displayed
7 as dash -- overloaded facilities indications and it provides
8 a good overview to see the system.

9 Now the operators can click on the stations and
10 drill down to the one line diagrams -- you can flip forward
11 Gerry --

12 (Slide)

13 -- here's just another view of the other side of
14 this one. I couldn't fit it on one slide but this stretches
15 across a 25 foot display -- and you have the ability to zoom
16 in, show more or click on a station one line diagram and
17 bring that up.

18 There's also another level we're creating, it's
19 an in-between level, a control area level, so like we could
20 click on, say IP&L and that would bring up all their
21 transmission facilities, 100 kV and above and show a good
22 detail down to the station level on that so you can get a
23 good control area view.

24 So there's going to be -- we have the two levels
25 now. We have the overview and the station one line diagram

1 view but we're implementing that middle view to help give
2 the operators a good picture of what's going on.

3 And this is -- we've been working on this kind of
4 expedited things over the last few months and it's a viable
5 tool we have now so I'd highly recommend to those that don't
6 have a map board to get one on your wall and keep it
7 dynamically updated.

8 It's -- the scan rate on this is 30 seconds, it's
9 updated every 30 seconds. Okay, next?

10 (Slide.)

11 Just a couple more views. This is one of the
12 station one line diagrams -- they click on those stations
13 and go to -- they could also pull them up on other displays
14 whether on the wall board or at their console, they could
15 pull these up.

16 And it has the megawatts, megabars, with the
17 voltages, status of breakers and equipment and so forth.

18 Next?

19 (Slide.)

20 Some more visualization. We have ability to
21 display things that, for the different control areas, look
22 at their tie lines coming in and a summary of their system,
23 age, frequency, you know, if you want to pull up that and
24 look at something that's going on in the area and you want
25 to give it a quick check, all the generators in the area and

1 critical bus voltages -- it's another way to visualize
2 things what's going on.

3 Next?

4 (Slide.)

5 Okay, more on the tools. While we have many
6 tools available to the operator, we are putting in place a
7 state estimator -- it's a 30,000 bus so if Mike Kormos is
8 still here, it's 30,000 and it's -- the status of this slide
9 right now, this slide says we will be utilizing it by end of
10 this month.

11 Well, it's in place for the operators now. It's
12 working well, solving every 90 seconds. Contingency
13 analysis, it runs 5,500 contingencies -- it takes about 10
14 minutes now to get through those 5,500 contingencies.

15 Some of the enhancements that we're looking
16 forward to is some parallel processing in that once a state
17 estimator case is built and solved and passed off to
18 different processors to run, it's put back together.

19 Some of the other things we're looking at is
20 better sorting -- of the displays. Right now these displays
21 are typically built around a control area environment, a
22 (inaudible) of views where we need to look -- multiple
23 areas, multiple (inaudible) areas, different ways of
24 prioritizing and sorting those and we're working with our
25 vendors on those enhancements.

1 And we do have back up tools that are flow gate
2 monitoring tool that has over 600 contingencies that
3 calculates post contingent flow with line outage
4 distribution factors. Those line outage distribution
5 factors are updated every 20 minutes based on the latest
6 system conditions and we can update them on demand in five
7 minutes.

8 That works off the SKADA data because there's
9 discussion earlier -- you don't want to wait for the state
10 estimator runs if the state estimator fails -- so you need
11 to have these back up tools and run these in parallel for
12 every critical tool to look at what your back up for this
13 state estimator is if it doesn't solve, what are you going
14 to have?

15 One of the enhancements we're looking at is,
16 well, this runs every 20 minutes and it does take operator
17 intervention to run a forced outage update to update these
18 line outage distribution factors now.

19 We're looking at having topology processing
20 running off a separate tool, not from a state estimator
21 result, but a separate analysis off the SKADA data to
22 populate this so it would automatically refresh these line
23 outage distribution factors so if you have problems with
24 your state estimator you can go right to this other tool.

25 We're also looking at putting in all facilities

1 in here like 230 kV and above is the first phase and then
2 100 kV - above later.

3 So really we want to have the -- best of both, a
4 good state estimator running, being utilized always, but
5 then good tools right there updated in real time for them to
6 look at and these sort consistently to bring to the top of
7 the page, the heaviest loaded lines, so it's -- in color
8 code above 95 percent, the different color for above 100
9 percent. So it's right there at their fingertips scanned
10 right what's going on in the system.

11 Next please?

12 (Slide.)

13 Okay, some more tools we're looking at and one
14 we're calling a delta voltage tool and it's really for real
15 time operation of some feature we're going to put into our
16 alarming that, if we have a step change in the voltage --
17 right now we're alarming on high and low voltage warning
18 levels, then emergency levels, flows -- warning levels then
19 emergency levels, and so forth.

20 But we're going to add in a step change in alarm
21 so if you see a three percent voltage change or a five
22 percent voltage change we need to define a criterion in
23 different voltage levels of what we're going to use, but you
24 can automatically alert to the operators that a contingency
25 occurred and you did have a significant voltage change.

1 Same thing with delta flow tool -- just another
2 tool, another place for them to look at if there's a step
3 change in the system and flows, they can see what lines are
4 involved and what lines went to zero, what lines have we
5 loaded and be able to view that and help them put the
6 picture together.

7 So all these tools, the state estimator, the
8 alarming, the flow gate monitoring tool, visualization tools
9 -- all provide an effective means in really a back up to the
10 state estimator contingency analysis -- if any one of them
11 fails.

12 The other thing we're looking at as far as
13 forward looking in some of the best practices is really some
14 filtering off of the state estimator to indicate any breaker
15 changes to put some smarts in it so instead of just seeing
16 breaker status changes you're seeing what equipment is
17 actually changing.

18 And also filtering by scheduled versus forced
19 outage, if you have a maintenance outage going on and you
20 know about it, you want to filter those out and make those a
21 lower priority and rely more on the forced outages.

22 So we're exploring that filtering by forced
23 versus planned right now and looking at the entire outage
24 schedule where it has all our maintenance in with these
25 tools to provide some good filtering.

1 Okay, next --

2 (Slide)

3 -- minimum tools. Yes, pardon me?

4 MR. CAULEY: (Inaudible.)

5 A couple more slides and -- yes, okay.

6 Minimum tools. I won't go through all of this
7 because we've already talked about it. But the list of
8 minimum tools that should be available to the reliability
9 coordinator including back up for each one if one fails and
10 instructions to know when to go to the back up tools, when
11 to go to your back up center or when to call on other
12 entities to monitor for you --

13 (Slide)

14 -- and I think we can just flip through that,
15 that's the alarm screen --

16 (Slide)

17 -- back up procedures, proper notifications for
18 these back up procedures, and really, I can just end there,
19 Gerry. Let the others talk.

20 Okay, thank you.

21 MR. CAULEY: Okay that was Dave Zwergel from the
22 Midwest ISO.

23 I have been asked by the web listeners to speak
24 slowly and clearly when we introduce speakers so they know
25 who's talking. It's a little more difficult to hear I think

1 over the little pipe you have on your computer compared to
2 being here in person.

3 Next speaker is Pat Duran of the IMO in Ontario.

4 MR. DORAN: Good morning.

5 From this morning's discussion I'm hearing three
6 fairly common themes and I think they're the three key
7 essential items in becoming a successful reliability
8 coordinator or system operator and those three things are
9 certification and training, authority through appropriate
10 standards and, certainly, operating tools.

11 This panel is going to talk about operating tools
12 however I think all three of those things are closely
13 related but we will touch on all of them as we discuss
14 tools.

15 Before I address the specific questions to the
16 panel I wanted to look at three recommendations that we've
17 made. The first that reliability coordinators must have
18 access to a suite of tools that allow them to exercise their
19 accountability and maintain the reliability of their
20 coordination area.

21 These tools must have the capability to define
22 and monitor interconnection reliability operating limits.
23 They must be able to assess contingencies, must have the
24 appropriate and reliable data to support the tools, and
25 clear information must be presented to system operators.

1 Off line studies and analyses must be performed
2 to define limits and study system conditions both pre and
3 post contingency and finally reliability coordinators must
4 have the training necessary to effectively utilize these
5 tools and interpret their results.

6 And I think that's key in that depending on tools
7 can really head you down the wrong path in that the
8 operators must have the training to (a) be able to interpret
9 the results and (b) be able to independently act if the
10 tools are giving them a suspicious or wrong result.

11 First question to the panel is 'what criteria for
12 observability of power system must be met to ensure reliable
13 operation and avoid cascading outages?'

14 Operators must observe all elements that can have
15 an impact on reliability. Identification and scope of
16 observation is therefore dependent on the specific system
17 and its operating criteria. NERC policy nine identifies the
18 criteria and functions of a reliability coordinator.

19 In addition to what's in NERC policy nine right
20 now, reliability coordinators must also be required to
21 control frequency, correct ACE, perform security assessments
22 and have monitoring programs to assess contingencies that
23 impact on a wide area or can cause cascading outages.

24 And some of you might say, "some of those
25 activities are controlled area or balancing authority

1 functions right now" and certainly they are, but where they
2 have an impact on the reliability of a wide area,
3 reliability coordinators also need the authority to act.

4 Next slide?

5 (Slide.)

6 The second question, our dynamic map board is
7 essential for maintaining a broad overview of system
8 conditions. Dynamic map boards are the preferred means of
9 providing operators with a broad overview of system
10 conditions, modern wall boards consisting of projection
11 screen arrays, provide flexibility in displaying key
12 information, zooming in on specific areas, and displaying
13 non traditional relevant information.

14 Our wall board and other tools are only as good
15 as the data they depend on. It's important (1) to have
16 sufficient data to provide adequate monitoring and (2) to
17 have redundant data and data communication paths to reduce
18 the risk of losing data.

19 Next slide?

20 (Slide.)

21 'What SKADA EMS functions are necessary to ensure
22 reliable system operation and what should be performance
23 criteria for each?'

24 The minimum required tools set for reliability
25 coordinators is established in policy (9)(d). These include

1 monitoring and analysis tools such as state estimators,
2 contingency analysis tools, communications facilities and
3 off line study and analysis tools.

4 This minimum set of tools should be expanded to
5 include adequate alarms to indicate when critical functions
6 are not updating and when data is not current. This
7 information is critical to ensuring that tools are to be
8 relied on when needed and are providing the proper results
9 to system operators.

10 Off line analysis is critical in identifying
11 interconnection reliability operating limits and without
12 adequate analysis to identify limits and to provide
13 sufficient monitoring of these limits to system operators,
14 they cannot maintain reliability.

15 System operators must understand where their
16 system is constrained, why it is constrained and what
17 mitigating control actions they can take to look after those
18 constraints.

19 Next slide please?

20 (Slide.)

21 In both real time and off line assessments
22 contingency analysis tools are only as good as the scope
23 they cover and the quality of data they use. The scope must
24 cover all limits. The models must be representative of the
25 system being studied and the data must be comprehensive and

1 accurate.

2 To ensure reliability the industry must shift its
3 focus from identifying and managing flow gates through
4 commercial processes like TLR to identifying and managing
5 interconnection reliability operating limits and remember
6 that flow gates and IROLs are not always synonymous.

7 In Ontario we have inter connective reliability
8 operating limits that are not modeled as flow gates because
9 they cannot be impacted by parallel loop flows so TLR is an
10 effective process in managing those limits.

11 NERC policy nine also identifies requirements for
12 the next day operations planning process. This includes
13 performing system studies and security analysis to ensure
14 that bulk power systems can be operated in anticipated
15 normal contingency conditions. This can only be done if the
16 reliability coordinator has the authority to manage outages
17 to transmission and generation facilities to ensure that
18 limits will not be violated.

19 Limits protect against voltage instability and
20 are dependent on minimum voltages being maintained, adequate
21 reactive resources being ensured and the planning time frame
22 through a comprehensive outage management process.

23 While it is important to obtain from neighboring
24 reliability areas that impact on your area, it is not
25 important to have visibility of all limits within a

1 neighboring area. This can lead to confusion where
2 interpretation of limits is required or where patrol actions
3 are already in place in that neighboring area that might
4 mitigate the impact of the contingency.

5 What actions are appropriate when mission
6 critical monitoring and control systems fail? A system
7 operator's tools must have a high degree of reliability
8 obtained through a redundant infrastructure and carefully
9 controlled change management process.

10 We talked a little bit about change management
11 and the impact on software applications earlier today and I
12 think that's an important aspect that we have to manage in
13 maintaining our software.

14 NERC policy nine requires a reliability
15 coordinator to have continuous monitoring of the reliability
16 area including provisions for back up facilities.

17 Policy six requires control areas to have a plan
18 to continue operation in the event its control center
19 becomes inoperable. However it does not address this as
20 reliability coordinators. Coordinators must have a complete
21 set of back up tools.

22 While defining the required tools is essential,
23 it is equally important to recognize their limitations. If
24 tools fail the back up is competence, experience,
25 preparedness and knowledge of operating staff. These should

1 translate into the ability to (1) correctly interpret the
2 results presented by the tools, (2) adequately assess system
3 conditions when the tools fail, (3) and finally to act
4 independently without confirmation by the tools to ensure
5 that the system is operating at a secure state.

6 Thank you.

7 MR. CAULEY: The third presenter on this panel is
8 Stephen Lee of EPRI, E-P-R-I.

9 MR. LEE: I would like to preface this by some
10 general comment. What EPRI is saying here is not new. It
11 is very common knowledge in industry for a number of years.

12 Gerry, next slide please.

13 (Slide.)

14 The research community really needs the support
15 and commitment of the entire industry to fix the reliability
16 problems. Restructuring really has not been accompanied by
17 (inaudible) commitment of resources to implement critical
18 pieces of infrastructures such as transmission capacities
19 and information technologies and, also, not enough
20 commitment to fund research and development.

21 Next slide.

22 (Slide.)

23 This a chart that shows the U.S. electric R&D
24 ranks in the bottom 20 industries. We do better than
25 railroads but we spend less money as percent of our revenue

1 than restaurants.

2 In 1999 according to NSF the total U.S. R&D in
3 electricity industry is only about \$422 million and I know
4 it's been declining because average funding has been since
5 declining about 10 to 20 percent a year.

6 Next slide please.

7 (Slide.)

8 On -- observability, the fundamental operation
9 grid has changed in the size of the network and the
10 monitoring of a particular authority has grown due to the
11 merging of functions in reliability coordination being a
12 human process brought time delay and potential human errors.
13 Both may result in less reliability so we may need to make
14 reliability criteria more stringent recognizing this
15 transition problem.

16 Observability really requires accurate topology
17 of the network. In the N - 1 criteria in the 30 minutes to
18 bring back into compliance should be examined for adequacy
19 in view of the effective restructuring and its transition
20 effect on operational complexities and in sufficient
21 training.

22 The effect of network size and larger footprints,
23 the effect of uncertain and long distance power transfers,
24 the effect of time delays introduced by congestion
25 management rules and tools such as IDC and COR, the effect

1 of an adequate of state estimator and IDC or topology
2 changes and realities of the N - 1 criterion really does not
3 explicit account for human errors, EMS alarm failures and
4 hidden relay errors which are really the major causes of
5 blackouts.

6 So 30 minutes may not be realistic because of
7 this human process. N - 1 itself may not provide sufficient
8 reliability margins so a study to establish the equipment
9 reliability and proposed restructuring would be useful for
10 establishing new reliability criteria and also probabilistic
11 approaches should be seriously considered for transmission
12 reliability.

13 Next slide.

14 (Slide.)

15 Our displays, yes, we definitely need dynamic map
16 boards and other displays such as wide area displays fur
17 situation awareness within home areas and across the entire
18 interconnection. For example, line close outages, dynamic
19 megawatt and megabar reserves, with accurate and common
20 data sources for common viewing that includes geographical
21 displays, bubble diagrams showing wholesale power
22 transactions and also visualization of transmission
23 bottlenecks and particular dynamic or real time transfer
24 limits, for example, using the community activity room
25 display.

1 Next?

2 (Slide.)

3 About minimum sub (inaudible) wide area
4 monitoring display, performance should be measured by the
5 time lag to explain retro values inside of 30 seconds to
6 measure data or five minutes for network topology data and a
7 system availability should be very high approaching that of
8 the EMS system such as 99.99 percent of availability.

9 Congestion management II needs to expand beyond
10 its own footprint either using LMP or IDC and also be
11 coordinated with other grid displays in the same
12 interconnection, for example, by applying the virtual RTO
13 concept.

14 We need system separation capability. Well
15 defined system separation boundaries can actually speed up
16 system restoration with proper training so we have really
17 got emergency resolution procedures based on well defined
18 boundaries and should be multiplied sets of boundaries to
19 restore the system faster.

20 In operator training simulators with snapshot
21 capability for off line studies can be very useful and
22 helpful for operators for doing emergency situation
23 restoration to solve real time problems they have not been
24 trained on before or encountered.

25 Next slide.

1 (Slide.)

2 About SKADA and EMS functions -- in addition to
3 state estimators we need to have topology estimation. Each
4 reliability coordinator should have one topology estimator
5 for rapid detection of line outages and the topology
6 estimator should automatically update the NERC SDX
7 continuously for the IDC and TRR process and before the TE
8 is operational we should require the SDX to be updated
9 frequently and regularly.

10 The state estimator does not work by itself. It
11 must be well supported by trained engineers on all shifts
12 and have a system availability greater than 99.99 percent.

13 We also need on line contingency analysis, on
14 line voltage stability analysis, and on line dynamic
15 stability analysis.

16 And something new that has to be developed is
17 intelligent alarm processing which includes operator advisor
18 to help operators really understand what is going on in the
19 system and also in the area of under frequency and under
20 voltage load shedding, these schemes need to be examined and
21 developed and well coordinated.

22 Next slide.

23 (Slide.)

24 As back up tools operator training simulators are
25 really inexpensive and highly effective for training

1 operators. Customized OTS replicating EMS will improve
2 operator effectiveness through regular drills and P/C based
3 OTS with small generic power grids and well developed
4 training exercises will help operators identify, analyze and
5 respond to unfamiliar operating conditions which often
6 appear under emergencies, classroom instruction and self
7 training materials to education operators on the engineering
8 fundamentals of power system dynamics, for example, the EPRI
9 power system dynamic tutorial report.

10 Finally, web based OTS would be useful for
11 coordinated training of drills among grid operators and
12 transmission operators.

13 Next and final slide.

14 (Slide.)

15 Are SKADA and EMS systems being properly
16 maintained?

17 I just want to bring out one point, that alarm
18 system and EMS software need to be really tested under
19 stress and heavy loading conditions so we know for sure they
20 will work properly under severe conditions.

21 Thank you.

22 MR. CAULEY: Okay thanks Steve.

23 The next speaker is Victoria Doumtchenko -- I
24 hope that's close enough -- and she's with MPR, which is a
25 human factors based company out of Northern Virginia.

1 So correct me where I missed your name or your
2 company.

3 MS. DOUMTCHENKO: Okay.

4 Good afternoon. My name is Victoria Doumtchenko,
5 that was right. I am with MPR Associates. We are an
6 engineering consulting company in Alexandria, Virginia.
7 Actually our business is in nuclear and non nuclear energy
8 and power and human factors is one of the specialties, I
9 guess, that we deal in.

10 What I wanted to talk about today is actually to
11 give a brief summary in our report findings that we looked
12 at that were particularly of interest to us to provide some
13 conclusions and recommendations and also talk about the
14 benefits of the application of the human factors engineering
15 process to control centers.

16 The Interim Report identified a number of
17 electrical computer and human events as causes of the
18 initiation of the blackout. What we noted as important was
19 that computer failures were probably indicative not only of
20 equipment problems but also the computer failures led to the
21 loss of situation awareness in the control room.

22 Next slide please?

23 (Slide.)

24 There were another number of -- I'm sorry, there
25 were a number of other reasons cited, among those are --

1 human errors, lack of procedures or inadequate procedures,
2 something that people have talked about a number of times
3 today, lack of monitoring tools for high level
4 visualization, lack of alarm indicating unavailability of
5 alarm systems and other supporting information systems.

6 I want to point this one out as probably one of
7 the highest priority problems that we saw.

8 Also lack of visibility of the status of key
9 transmission elements in neighboring systems, basically a
10 lack of adequate data provided to the operators that would
11 probably enable them to make the decisions on a timely basis
12 and make correct decisions and finally inadequate operator
13 training, again, something that we talked about a number of
14 times today.

15 The conclusion that we came to after analyzing
16 this in the Interim Report findings was that probably a
17 failure to appropriately include human factors engineering
18 into the design of the control centers and training of the
19 operators may have been the major contributing factor to the
20 events of the blackout.

21 The recommendation that we provide is to apply
22 human factors engineering process consistent with the so-
23 called "graded approach" to derive practical focus benefits.

24 Now the term "graded approach" comes from the
25 nuclear industry actually. It's an NRC defined term. It's

1 a well documented research and mature process which
2 basically says that human factors engineering needs to be
3 tailored to specific application applied to the degree
4 commensurate with the level of effort required to understand
5 what is important for a particular situation or application.

6 Next slide please?

7 (Slide.)

8 The benefit that we see would come out of the
9 application of human factors engineering to control centers
10 would be first of all helping to ensure that situational
11 awareness is maintained under all operating conditions and
12 we're talking about normal operating conditions and
13 emergency operating conditions, of course.

14 The type of recommendations typically as an
15 example that would come out of this kind of evaluation
16 process would include providing a control center-wide
17 indication of multiple alarm system failure, providing an
18 effective functional overview display, also improving alarm
19 presentation and alarm prioritization to make alarms more
20 intelligent and minimize the number of nuisance alarms and
21 alarms that demand an operator response.

22 I want to mention that, as far as alarm
23 presentation prioritization is concerned, there has been
24 sufficient -- there has been a lot -- of research done and
25 MPR has participated in that. There are some publications

1 available, some reports that we have produced for the
2 research sponsored by EPRI and you see the references on the
3 slide.

4 Some other benefits would include -- next slide
5 please --

6 (Slide)

7 -- improving crew coordination and in their area
8 the type of recommendations the type of benefits I guess we
9 would see is improving procedures, training, improving
10 communications and improving peer checking.

11 We would also seek to decrease the probability of
12 human error currently -- the recommendation that we would
13 like to provide is to use human reliability analysis to
14 identify design teachers to minimize human error, allow
15 detection of human error and also -- very important --
16 provide an accurate recovery capability.

17 Another couple of benefits here is to minimize
18 the potential for and the consequences of, failures when
19 human errors or human failures occur so we need to
20 understand that we can try to minimize human error but this
21 is not something that we can avoid.

22 So for that, we would stick to use failure modes
23 and effects analysis to identify this kind of failure, both
24 human and equipment failures, and understand their effect on
25 operations.

1 Last but not least is helping to ensure that both
2 test requirements and human capabilities are appropriately
3 included in the design so what we're talking about here is
4 using task analysis to make sure that requirements for
5 displays that are processing controls displays and alarms
6 communications and operator support aids are identified and
7 appropriately included into this design to make sure that
8 the operators can accomplish the tasks that they need to
9 accomplish under all operating conditions and under any
10 operating mode we can think of.

11 The reason why we think this approach is going to
12 work is because human factor engineering is not new. In
13 fact, MPR and the nuclear industry as a whole have a lot of
14 experience with that.

15 Of course, the TMI II accident was probably the
16 starting point where people started paying attention to
17 that. Basically what we saw was that the TMI II accident
18 showed that, at the heart of it was a simply human factors
19 interface problem.

20 All nuclear plants were required to perform a
21 detailed control room design review following the accident
22 and a whole number of problems were discovered and a number
23 of modifications were made as a result of the VCR DR effort.

24 Those included improving human system interface,
25 operator performance, performing alarm systems upgrade,

1 including the one that I mentioned in the beginning of the
2 presentation -- providing an indication that an alarm system
3 is no longer functioning.

4 Also, human factors engineering reviews were
5 incorporated into the indemnification process and system
6 health monitoring was also provided.

7 So the bottom line is we know that the August 14
8 event showed us that significant human factors issues exist
9 in control centers. There is however a well defined
10 methodology that we think can help evaluate these issues and
11 find practical solutions and we recommend the human factors
12 engineering process because we see there are some clear
13 benefits that can be derived from that.

14 Most importantly we can reduce risk and increase
15 the reliability of operations.

16 Thank you.

17 MR. CAULEY: Thank you Victoria.

18 And the final speaker for the panel is Don
19 Watkins of the Bonneville Power Administration and Don is
20 working with Vicky Van Zandt and also Tim Cousy from the NEB
21 in Canada who couldn't be here today and Don is filling for
22 him but they're all on the operations investigation team and
23 Don has a few closing comments on this topic.

24 MR. WATKINS: A few? More than a few.

25 So hear me out because all of this has been said

1 very similarly -- things that we've had different
2 perspectives on -- and I know it's hard to listen but I'm
3 going to speak fast just like most of these guys did because
4 there's a lot of stuff.

5 So throw away a lot of stuff but there may be a
6 few things in there to get.

7 The first note I want to make is from an earlier
8 presentation because I think it's really key to our culture.
9 It's not just our tools. And it's about the inquisitiveness
10 -- and it was spoken of with regard to operators -- but I
11 think that's a real high need we have all over and that is
12 borne out of visiting some of the key control centers in
13 this blackout and listening to hours of transcripts and this
14 and that.

15 We do our job routine stuff 99 percent of the
16 time and the average is zero percent that operators or
17 engineers or managers have to deal with true blackouts or
18 disturbance -- is zero, right? The average effectively,
19 right? Because very few -- only a few people on a shift in
20 a few utilities.

21 So we need to think about how do we think outside
22 the box? I won't say any more on that but we need to think
23 about that at the root because we can have all the tools,
24 all the systems, all the processes, all the monitors and, if
25 we're not thinking outside the box, we'll still miss it.

1 So what's the criteria for observability? And I
2 went more generically because these are all really relevant.
3 You have the breadth, the resolution, the accuracy and the
4 timeliness. And these were all issues in this blackout.

5 The breadth really has to do with a lot of stuff
6 and one of those is you've got to look at your lower voltage
7 systems, too. Your lower voltage systems usually have
8 limits and they have a lot of the reactives, so if you're
9 modeling it, you need to look at those.

10 Another part is you need to know your breaker
11 status and all of your analogue information and you not only
12 need it for your system jurisdiction, you need it into the
13 area that you could affect or the area that could affect
14 you.

15 And that stretches a number of busses out from
16 your direct area of control.

17 The other thing you should know is, let's say Bob
18 comes up here with a nomogram for you about Lake Erie and it
19 might involve -- I don't know if he's going to -- but it
20 might involve the IMO, Eastern Pennsylvania and all the way
21 through, right? Detroit, the whole thing through.

22 In that case, if that's part of the nomogram and
23 you're part of it, you really should be able to see all of
24 the information around that that involves that nomogram.
25 You need to see that data.

1 So that's the breadth. That's -- really
2 important. All these are, though.

3 Resolution is really important and that really
4 speaks more specifically to the lower voltage. You'll hear
5 a lot when you start speaking about reliability coordinators
6 and ISOs. You'll be hearing about 230 and above and the
7 problem is, at least in our system and I think -- I know
8 it's true -- of this system, too, a lot of limits, parallel
9 lines are in the 138, the 115, the 69, the 39 kV stuff.

10 Just beware, that's important.

11 Accuracy. Accuracy really messes up state
12 estimators. If you've got really bad data in which -- trust
13 me, when we started doing data exchange, and I'm sure it's
14 the same in the East, there's a lot of rotten data out
15 there. I mean, you're getting it but it's bad. And it
16 really messes up state estimators, right? It confuses them.
17 It makes them not solve sometimes and give bad results.

18 So be careful.

19 Also -- I need to see what I was saying here.

20 You have a tool to check accuracy and it's a very
21 effective tool and it's probably the main thing you can use
22 this tool for is the state estimator because it tells you
23 when your data isn't matching right. It tells you
24 mismatches and how much it has to correct and, if you pay
25 attention to it, you'll go out and get technicians out there

1 and they'll adjust those values so they fit so you have a
2 tool to get your data accurate.

3 The next one is timeliness. There were a lot of
4 problems with timeliness on August 14. A lot of problems.
5 And timeliness is about seeing the same data at the same
6 time. There were a lot of conversations where people were
7 seeing different snapshots of the same data and they were
8 different -- some were really high, some showed huge
9 overloads -- and yet they weren't sure and they didn't trust
10 the numbers because the others didn't have the same number.
11 It leads to a fuzziness in the brain and you don't act as
12 quickly when you don't have it.

13 So I'm going to suggest there's a couple things.
14 One is you have a time skew due to your data samplings,
15 right? The rates of scatter samples? Usually that's pretty
16 fast, though. You have a time skew due to data
17 transmission. A lot of the data is picked up by the ISO
18 reliability coordinators at 30 second increments. That is
19 great if you're dealing with hourly problems, right? The
20 stuff you can do at TLR for the next hour.

21 But if you're dealing with an emergency right now
22 where lines are going down, lines are overloading and so on,
23 30 seconds is way too long especially on status, although I
24 know sometimes status updates more quickly.

25 And the last one is, when you're looking at a

1 state estimator, that also has a skew. It may be anywhere
2 from the 90 seconds as described by Dave to five minutes and
3 five minutes is a reasonable period to run on a state
4 estimator.

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1 Beware. Operators should be probably using raw
2 data and using the SE to do the tools and also just to check
3 data.

4 The next thing -- and going to the next question
5 here -- oh, by the way, think on a time skew, I would think
6 that on all of these things, you should move everything in
7 terms of data transmission and sampling rates to the five-
8 second timeframe. Think about that, because that's still
9 going to allow some time skew. It could be ten seconds or
10 so out, but just think in terms of that.

11 Are dynamic map board essential for maintaining
12 broad overviews? We have good scatter displays, and there's
13 been quite a move to move away from even having map boards.

14 And there are some utilities that do not have map
15 boards, and there are some that have them, but they're
16 pretty static; there's only a little bit of information. So
17 I don't know the right answer to that, but I do know that
18 you need someplace where you can look at the same
19 information, the same way, every time, and when you have a
20 map board, whether it's a projected one like Dave was
21 talking about, which hopefully is the same one almost all
22 the time there, or whether it's tiles, with the lights and
23 some analog values in them.

24 What happens is that when you walk into that
25 control room, you know exactly what you've got by exactly

1 where the lights are. You can assess your system just like
2 that, because it's the same except for what's changed in
3 terms of breaker statuses and values. So, map boards are
4 really important from that perspective. They give you a
5 larger overview, very quickly, and you'd assess it just like
6 that.

7 If you're looking at displays, sometimes it's not
8 that way because displays keep changing. It's just the way
9 it is.

10 The problem with all of these though, all of the
11 dynamic stuff, is that it's usually driven by the EMS
12 system, as all our strip charts are these days. So if you
13 lose your EMS system -- this is going to answer a later
14 question, too -- if you lose your EMS system, you're often
15 gone, and so you need to think carefully about that.

16 One way would to be to provide some alternative
17 paths to feeling a map board and maybe stripping information
18 off of RTUs before they get into the EMS scatter system.

19 What minimum set of operating tools should the
20 operators and reliability coordinators have? I'm going to
21 deviate a little bit, so try to listen, and you can ignore
22 me and not like it if you don't.

23 But I think that at the root of a lot of our
24 issues is that while our power systems are extremely
25 complex, they are extremely complex from an engineering

1 point of view, and we've done amazing things with control
2 and operation of systems, let no one fool you. It's an
3 amazing system, but I'm going to suggest that our methods of
4 transmitting data between our utilities about the
5 transactions we're doing and the ability to change those in
6 real time and learn from our data, is abysmal.

7 We don't -- we're developing that, but we do not
8 have real good data exchange methodologies and common open
9 standards for doing that. And I'm going to suggest that
10 this is essential.

11 If we know our transactions and we can look at
12 those from the birth of the transaction, whether it's a
13 bilateral deal for energy that has to find transmission
14 eventually, right, and then has to be settled, even that, as
15 well as all our power system information, our models for
16 business and for the physical system, if we get those in
17 there, then we can see them, we can see all the causes and
18 effects, and we can also influence them.

19 If we had transaction systems in a standard,
20 common, open system, a real-time operator could go hit a
21 couple buttons, because all the information is there, and
22 send that information to the parties and they take care of
23 it, you know, as far as adjusting generators and so on.

24 There was a mentioning of the over-dependence on
25 the telephone. We need to get off of that into a dependence

1 on reliable data systems that pass the key information
2 between us in an open, standard way, not a bunch of separate
3 ways.

4 We need better models. Do you know whether your
5 AVR on a generator is running, is on or not, is really
6 important? And for us, whether your power system
7 stabilizers are on or not really matters, too. And we don't
8 get that information commonly in our RTUs and so on.

9 So the other problem we have is that even though
10 we have models of everything on the system, a lot of it isn'
11 right, how we model our responses to things, how we model
12 what happens with TAPs, and there's just a lot of stuff.
13 When you get into studies, you find out our models aren't
14 really good. We need to work on those. So those are tools.

15 We've already talked about online tools. It's
16 just important. Those are deeply important, and we only do
17 thermal right now. We really need to think about voltage
18 stability, and we really need to think about dynamic
19 stability.

20 There are problems there, and sometimes I think
21 there are a lot of problems and we don't even have a clue
22 about them because they come and they go and we're just
23 lucky nothing happens. So, there's a lot of work to get to
24 that, but we need to do it.

25 So, let me tell you something else: Online

1 tools, they quit in the most important times you could
2 imagine. And ask MISO, you know, about August 14th.

3 They have good tools and they're reliable, and
4 while they were called developmental, they were pretty well
5 developed. And they didn't work during that period, and
6 there were others that didn't, and quit at various times.

7 So you need to -- so this is my lead-in to say
8 that you also need to have good offline tools. You need to
9 have good offline study tools. That means keep your models
10 up to date. If you're responsible for operation, keep your
11 offline, whether it's a PTI or GE database or an IEEE,
12 whatever it is, keep a database that's fairly up to speed so
13 that you can quickly look at your system and study it,
14 because your online tools may not be there when you need
15 them.

16 We need tools to accomplish real-time load
17 shedding. You need to be able to dial in -- and this isn't
18 everywhere and you can't do it in some places, but where
19 possible, we need to be able to dial a number and do our
20 SCADA system and have it trip that amount of load within
21 sub-minutes. That's important.

22 Hopefully we'll never use it, but they need to
23 be in our tools.

24 MR. CAULEY: Don, two minutes.

25 MR. WATKINS: Okay, I'm going to move quickly.

1 And the last one on the tools is, we need robust tools, and
2 by "robustness," I mean, is my system healthy? Right now,
3 we do our study tools, all based on our assumptions of what
4 the models are, what the contingencies are, what ails the
5 system.

6 And somehow we need to identify key indicators of
7 the system health. You know, our doctor looks at our
8 throat, looks in our ears, takes our blood pressure and our
9 temperature and so on to determine whether we're healthy or
10 not. We need those same tools in the power system, so if
11 we're wrong in our analysis, it still may capture
12 instabilities or things that aren't healthy in our system.

13 Often there are voltages that change. You know,
14 when your power changes a little bit and you want to look at
15 how much your voltage changes, sometimes that changes, and
16 that's an indicator of ill health. Sometimes your angles
17 are really high on the system, your power angles, and
18 sometimes those are indicators of bad health.

19 Sometimes there are oscillations going on, kind
20 of in the background that aren't damping; those are
21 indicators of health. We need to look at tools that take
22 responsibility for the fact that we might be wrong in our
23 assessments of all that we know in our infinite wisdom about
24 the system.

25 So I'm looking through what I'm going to say

1 quickly here, because I'm just about out of time.

2 So, I'm going to go, what is appropriate for
3 mission-critical monitoring and control systems? What if
4 they fail?

5 I'm going to say that you almost have no
6 alternatives if these fail. If your control systems fail,
7 you're really in a heap of trouble. The best you can do is
8 what First Energy was doing a good job as they started
9 realizing their system had failed; they were calling out
10 operators to go to different stations.

11 But that's not going to work. I mean, they're
12 looking at something in their station, they have to get
13 there, and your system could be in a lot of trouble. So I
14 would suggest, and I'm sure there are things you should do,
15 but the thing you should focus on is keeping a very
16 redundant, extremely reliable control system for your bulk
17 grid stuff.

18 You know, you might be able to afford some
19 distribution things or sub-transmission, but when you're
20 looking at your bulk grid, you better have very, very good
21 tools, have them redundant, and you probably better have a
22 really good backup control center that can take full control
23 and not have common mode failures.

24 And that is all I'm going to say.

25 MR. CAULEY: When the transcriber's fingers

1 caught on fire, I knew we had to bring that to a close.

2 (Laughter.)

3 MR. CAULEY: I heard somebody running back there
4 with a fire extinguisher.

5 (Laughter.)

6 MR. CAULEY: I know you're all hungry and would
7 like to go on a break, but I would like to catch, if there's
8 any sort of momentum of burning issues and questions from
9 our distinguished investigating management team, and we'll
10 do that for just a few minutes and then we'll break and come
11 back to the questions, further questioning of this panel. I
12 don't want to short-change it, but I'd like to catch any
13 burning high priority issues before we break for lunch. I
14 see Alison is ready to speak.

15 MS. SILVERSTEIN: I have one --

16 MR. CAULEY: This is Alison.

17 MS. SILVERSTEIN: Alison Silverstein, Federal
18 Energy Regulatory Commission. Sorry I was late. I had to
19 give a speech.

20 The question is this: Y'all have given us a
21 great list of tools that everybody ought to have, but
22 particularly for Steve, how many of those tools are ready
23 for prime time in terms of -- they would all be great
24 things, but how many of them can I buy off the shelf or pull
25 out of a box today?

1 MR. LEE: (Inaudible) one of the pretty good
2 tools commercially available, right? The varieties of wide-
3 area type displays, too, are also available. So I think
4 these are two set of tools that are immediately available.

5 Alarm processing projects, the operator have
6 advisory type of tools, are still in development, so, there
7 are certain other tools that need to be developed for
8 quicker deployment.

9 MS. SILVERSTEIN: Anyone else?

10 MR. WATKINS: I would just say that a lot of the
11 tools that we talked about are available. They just need
12 development and a lot of stuff to be done that would get you
13 80 or 90 percent of the way.

14 MS. SILVERSTEIN: When you say they are available
15 but they need development, what does that mean?

16 MR. WATKINS: You know, the problem isn't the
17 algorithm, often. A state estimator and the contingency
18 analysis tools, the real problem usually isn't the algorithm
19 itself; the biggest problem is simulating the data and
20 making that work and getting automatic ways of reflecting
21 changes in the topology, et cetera. And that takes a lot of
22 resources.

23 MS. SILVERSTEIN: Does that it mean it's the
24 dataset collection and the tailoring and the care and
25 feeding of these things that's really the challenge?

1 MR. WATKINS: Yes.

2 MS. SILVERSTEIN: Not the acquisition of the tool
3 itself?

4 MR. WATKINS: Almost everybody has a tool and
5 offers it, but making it work is a whole different issue.

6 MS. SILVERSTEIN: Thank you.

7 MR. CAULEY: Any other questions? Dave Hilt?

8 MR. HILT: I just have one: I appreciate that
9 because we had asked earlier this morning -- and, Alison,
10 you didn't get to hear it, but I would ask this panel the
11 same thing. We were talking about having wide area
12 monitoring and effective tools to do that, and was there any
13 shortcomings in terms of developmental activities by
14 software vendors, et cetera, whether there were some things
15 that the industry needed to address or encourage along those
16 lines.

17 Secondly, though, I want to talk a little bit
18 about -- I know Pat mentioned lost the primary the primary
19 control center, as did David, as did Don, all of you talked
20 about that a little bit.

21 And some of you folks talked specifically about
22 for the reliability coordinator, that they did have to have
23 a backup center, needed to have that. Don just talked a
24 little bit about the control area net and having that. I
25 know that the standard does not require that. It says that

1 they have to have a plan for the loss of the center, but
2 your view of it was that they needed to have a major
3 transmission system and you really needed to have an active
4 backup control center.

5 Is there a size where you think that's necessary
6 or is there some cutoff? Certainly there are a lot of
7 small control areas out there. What's your view on that as
8 to at what point you think really a backup control center is
9 absolutely necessary, versus doing what you were talking
10 about, manning the various substations?

11 MR. WATKINS: So you've heard the comment that
12 the devil is in the details. So we make this wide, sweeping
13 statement that says that for the bulk grid, you shall have
14 backup control centers, but then we'll have an age-old year
15 of argument over it, over how big is that?

16 All I know is that we're moving toward very large
17 integration for the reliability authority and
18 responsibility. If you look at PJM New York, New England,
19 you look at ERCOT, you look at the California ISO,
20 Bonneville runs most of the bulk grid in the Northwest.

21 Those certainly are the size that they better
22 have very good stuff. I'd say anything that serves several
23 major population centers, you know, several towns of several
24 hundred thousand or more, you know, something that gets
25 where you're affecting the whole economy, the industry, et

1 cetera, of a fairly large area.

2 MR. HILT: Just from a business continuity
3 standpoint, if nothing else.

4 MR. CAULEY: Tom or David?

5 MR. MEYER: Just a comment.

6 MR. CAULEY: This is Dave Meyer, DOE, for our
7 online people.

8 MR. MEYER: A comment that others may wan to
9 amplify on: I'm struck at how many times I've heard about
10 the interlock between training operators and the use of
11 tools, particularly new tools.

12 I've already heard stories from some of you about
13 what seems to be a relatively slow rate of adoption of some
14 of the new tools that have become available recently. So
15 one of the lessons that I'm getting out of this is the
16 importance of training in order to use the tools that we do
17 have available.

18 MR. RUSNOV: Dave has covered a couple of my
19 comments. My other comment is that I guess the panel
20 reminded me of back in the days when I actually did some
21 load flows and transient stability studies, and every time I
22 picked up a base case, I was almost terrified of opening up
23 the damn thing because of the number of errors.

24 The errors came about honestly. (Inaudible)
25 wants to do a particular study and says, well, that piece of

1 data doesn't matter, and I don't have the precise
2 information, so I'm simply going to put it in an
3 approximation. It's good enough for what I'm doing. They
4 do that without ever removing it, and it stays in the damn
5 thing until ultimately you get a large accumulation of bad
6 representation of transformer TAP changers or generator
7 controls, et cetera, something that really has to be
8 watched.

9 MR. CAULEY: Alison, another one?

10 MS. SILVERSTEIN: I'm trying to figure out how to
11 ask this question so that I get the right answer. I don't
12 want to ask who has or what organizations have the best
13 tools out there, but rather for the kinds of tools that
14 y'all are recommending, can you tell us individual or a tool
15 and an organization that has the best kind of thing out
16 there, so that we can get a sense of who's got the best
17 stuff? What are we looking for? Does anybody have all the
18 tools that are needed?

19 MR. CAULEY: Is that a rhetorical question?

20 (Laughter.)

21 MS. SILVERSTEIN: I didn't think so.

22 MR. WATKINS: There's a bunch of tools. You
23 know, the online tools are well established in the planning
24 environment, and there are three or four providers for that
25 and we know who those are.

1 But those will have problems, you know, as
2 mentioned. The online tools, you know, I think that the
3 three larger of the companies, AVB and ESKA and Siemens,
4 provide good tools, you know, for doing that.

5 I think each utility needs to understand that
6 they need to understand what's involved with managing those
7 tools or implementing those tools. I think that's where
8 we've fallen down.

9 With our vendor, we've had the tools for many
10 years, but it's taken us years to get them where they are
11 accurate. So the tools that -- I think I better shut up.

12 MR. CAULEY: We stuck our toe over the antitrust
13 line, just a tad for you there, with not mentioning vendors'
14 names and if you want to submit response to that in terms of
15 specific vendors that you think have certain tools, I'd ask
16 you to do that after the conference with Alison.

17 Any other generic response to the question?

18 (No response.)

19 MR. CAULEY: Okay. What I think we should do is,
20 it's 12:30. I appreciate your patience in enduring the
21 extra half hour here. But I think it puts us in good
22 position to wrap up this afternoon in a timely manner, you
23 know, sometime between 4:00 and 4:30, hopefully, because
24 we're just a tad ahead of schedule.

25 When we come back from lunch, we will ask again

1 if there are any further questions of this panel or anything
2 we've covered in the morning, and then we'll go into Panels
3 D and E. I'd like to get the panels for D and E to bring me
4 your presentations now during lunch.

5 I will be so bold as to say, even though we don't
6 have lunch served, that we can be back in one hour and
7 restart at 1:30, with the hope of getting out of here by
8 4:00. Thank you.

9 (Whereupon, at 12:30 p.m., the technical
10 conference was recessed for luncheon, to be reconvened this
11 same date at 1:30 p.m.)

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AFTERNOON SESSION

(1:40 p.m.)

MR. CAULEY: I need to get the Panel D folks up here, Panel D, Paul Roman, Frank Macedo.

(Pause.)

I appreciate you all making a rapid turnaround on lunch. That will let us stay on track and make all our travel arrangements this afternoon.

Before we launch into Panel D, what I'd like to do is see if there's any other questions or comments from this morning's session, in case you hadn't digested it over your lunch. The three panels this morning were focused more on operational issues, reliability coordination, operator tools, emergency response, and so on. This afternoon is going to focus more on system planning, design, and analysis and protection, and so it's a good time to pause here and see if there are any questions left over from this morning, particularly for Panel C. We kind of cut them short there before lunch. And Myer Sason (ph.) of Con Edison has his hand elevated.

MR. SASON: Yes, as far as Panel C, I just had one comment. One of the things that was discussed was the need to make sure that like transactions that are being made, seem to work, bilateral transactions was mentioned, but somehow that information needs to be brought to a single

1 place so it can be evaluated from the point of view of
2 reliability.

3 And I just wanted to say that's what SMD is all
4 about, that's what the LMP systems are all about. Those
5 systems like in PJM, New York, New England, that have LMP,
6 what's scheduled is what's reliable. And if it's not
7 reliable, it's not scheduled that way; it's rescheduled,
8 maybe at a higher cost, but in a way that it is reliable.

9 So under no conditions are any of these
10 reliability coordinators, ISOs, RTOs, scheduling either day-
11 ahead or real-time unreliable power flows, and not from a
12 point of view of normal, but also from a point of view of
13 contingency.

14 So I thought that comment might be useful on the
15 previous panel. Thank you.

16 MR. CAULEY: Okay. Any other comments or
17 questions or inputs to the Panel C or any of the three
18 panels this morning?

19 (No response.)

20 MR. CAULEY: Okay, we'll move on into Panel D,
21 which is looking at system planning, design, and maintenance
22 issues. And we'll start off with our expert panel with Paul
23 Roman from NPCC.

24 MR. ROMAN: Yes, my name is Paul Roman. I'm a
25 member of the NPCC staff, and my presentation today will

1 address six of the seven Panel D questions. Next slide,
2 Gerry, please.

3 (Slide.)

4 MR. ROMAN: Okay, the Northeast Power
5 Coordinating Council or NPCC, is the regional electric
6 reliability organization for Northeastern North America, and
7 it consists of the Province of Ontario, New York State, the
8 New England states, the Province of Quebec and the Maritime
9 Provinces. And those are also the respective NPCC areas.

10 Next slide, Gerry, please.

11 (Slide.)

12 MR. ROMAN: Okay, Question 1 deals with the
13 seasonal and planning assessment studies that are conducted.
14 In NPCC, we participate on quite a few of these appraisal
15 studies or we conduct them.

16 First of all, there's the NPCC overall system
17 assessment study, and this addresses all aspects of system
18 operation, and it also covers the thermal limits on the
19 system and the bulk power system, the stability limits, and
20 also voltage limits.

21 In addition, there's also a probabilistic
22 assessment that's done for each summer, and that determines
23 the loss-of-load expectations of the NPCC areas.

24 Another study we participate in is the MEN
25 seasonal appraisals. And MEN stands for the MAC, ECAR, and

1 NPCC regions. And in these studies, we determine the
2 directional, region-to-region transfer capabilities and also
3 we conduct simultaneous transfer capabilities, and we
4 determine those limits for these wide-area-type transfers.

5 Now, in addition, within NPCC, the individual
6 areas also conduct detailed studies where they look at more
7 localized type transfers and more localized type limits.
8 Also within NPCC, the NPCC areas are required each year to
9 do reviews of future transmission and resource adequacy.

10 Now, in conducting these studies, the NPCC areas
11 must follow the NPCC planning and operating criteria. And
12 this is really referred to as the basic criteria and it's
13 included in or it's contained in the A-2 document.

14 I'd just like to mention that all of the NPCC
15 documents, the criteria, guidelines, and the procedures, are
16 all accessible from the NPCC website.

17 Now, the NPCC operating and planning criteria
18 establishes a design basis approach, in that the system is
19 designed to withstand certain contingencies, certain types
20 of contingencies, and then that's consistent with the
21 operation of the system, that is, the system must also
22 withstand those same types of contingencies.

23 Now, included in the contingencies are, first of
24 all, loss of single-element or N-1 contingencies, but also
25 in our criteria, we do have contingencies that result in the

1 loss of multiple elements. Examples of these include, tower
2 fault or as a result of delayed clearing, you could result
3 in -- may result in the loss of two or more elements.

4 Now, one thing I'd like to point out: I guess it
5 had been pointed out by some other speakers earlier, that
6 these criteria are -- they do meet the NERC requirements,
7 but in some of these cases, they exceed NERC requirements
8 and they also exceed what most other reliability regions
9 require.

10 And some of this is the result of lessons learned
11 from past blackouts like 1965, 1977. Some of that resulted
12 in looking and doing these things.

13 Question 2: This addresses the system models and
14 the accuracy of the system models that we use in the
15 assessment studies, and we feel that within NPCC, the models
16 we use are conservative in the power flow and dynamic system
17 studies that we conduct.

18 First of all, we model peak loads. For the
19 reactive component of the loads, we use the best estimates
20 we have. In addition to generation dispatch, you try to
21 choose generation dispatch that stresses the system, and you
22 also do that for the type of transfers that you simulate.

23 Now, regarding the generator reactive output
24 limits, those generally are limits that have been
25 demonstrated through actual testing at full capability of

1 the machines. You know, we tried to institute the testing
2 as part of determining, you know, what should we use in
3 studies?

4 Now, the development of the models, the base
5 cases we use, do go through extensive fine-tuning at several
6 different stages. They go through the NERC MMWG process.
7 Also within NPCC, we have a similar process. It's through
8 the SS-37 working group and also the individual NPCC areas
9 go through a lot of fine-tuning of these cases.

10 I know that the question came up earlier about as
11 far as finding errors in these, well, you know, you try the
12 best you can to clean them out, and it depends on how
13 dedicated you are to doing that.

14 In addition, we have an NPCC procedure, the C-29
15 document that does outline and indicate the procedures for
16 system modeling, addresses data requirements and facility
17 ratings.

18 Okay.

19 (Slide.)

20 MR. ROMAN: Question 3 addresses facility ratings
21 that are used in studies. Now, the normal and emergency
22 ratings are actually established by the facility owners and
23 they use area-specific parameters that are consistent with
24 that last document I referred to, the C-29 or the system
25 modeling document.

1 Coordination of ratings: Well, they are
2 coordinated on a regional basis, and a lot of that
3 coordination is done through the base case development and
4 fine tuning process where you see the neighboring regions or
5 neighboring systems try to make -- you have to be consistent
6 on tie lines and that's a big part of that.

7 In addition, we do have procedures in place to
8 relieve and deal with overloads, should they occur, so that
9 is something we also do have in place, those kinds of formal
10 procedures.

11 Question 4 deals with voltage support, voltage
12 control, and the adequacy of reactive reserves that we
13 maintain on the system. Now, the NPCC area planning and
14 operating studies actually evaluate the system voltage
15 limits.

16 Within NPCC, there has been emphasis on voltage
17 limits and voltage control for a very long time. The actual
18 -- some of the major interfaces within NPCC areas are
19 voltage-limited, and the limits are calculated and
20 significant margins are applied to determine where do you
21 actually operate to.

22 And in addition, we've added reactive control
23 devices over the years -- shunt capacitors -- but there are
24 also a number of static compensators on the NPCC systems,
25 and we've also had a fax device added in the middle of New

1 York State a few years back.

2 In NPCC, we do have a guideline regarding the
3 inter-area voltage coordination. That's the B-3 document,
4 and that indicates some of the guidelines for how to do
5 voltage control in the bulk power system. In addition,
6 there's an accompanying document, the C-4 document, for
7 monitoring that guideline.

8 I'd also like to point out that within NPCC, the
9 reactive resources are essentially coordinated, and that is
10 because each of the areas is an essential operator. They
11 also have control to control voltage resources such as
12 switching capacitors, reactive limits, things like that,
13 ordering plants to higher limits.

14 Regarding Question 6, this is related to the
15 evaluation of simultaneous transfer capabilities, and as I
16 mentioned earlier, the MEN studies, as part of those
17 seasonal studies, every time, they do calculate simultaneous
18 transfers for wide area type transfers.

19 Now, I'd also like to point out, too, that in
20 those studies, they compare operating points to the previous
21 year's study to try to validate that you are operating
22 within the limits that had been calculated, to really try
23 to provide some validation for operation versus what you'd
24 done in these studies to show on a seasonal basis, what you
25 expect.

1 We've also been involved in some other related
2 type regional studies such as the Regional Planning Forum
3 and also the Lake Erie Emergency Redispatch.

4 Now, regarding contingencies evaluated, I did
5 mention that earlier about the basic criteria document, and
6 that the criteria do tend to be more stringent than what's
7 required at NERC and what other regions use. I also, I
8 think it was pointed out earlier that some of the areas also
9 can have more stringent criteria, and in some cases, they
10 do. An example is southeastern New York.

11 Also, we do in NPCC, have provisions in the basic
12 criteria for conditions where we operate under high-risk
13 conditions, so that is something we formally have in the
14 procedures. And just in summary, based on the seasonal
15 assessments that we do, system modeling we have, and the
16 criteria we have in place, we do feel those are adequate to
17 avoid and minimize the occurrence of major outages.

18 Now, obviously through the blackout, the August
19 14th blackout, we are looking and trying to look into that
20 to try to review and come up with lessons learned.

21 And just as I pointed out, at the NPCC website,
22 you can access all of our documents there, and it's indicated
23 on the slide as npcc.org.

24 MR. CAULEY: Our second panelist is Shinichi
25 Imai, from Tokyo Electric.

1 MR. IMAI: My name is Shinichi Imai. I am from
2 Tokyo Electric Power Company in Japan. I have more than ten
3 years of experience of power system operation and for system
4 protection.

5 I really appreciate this opportunity to make a
6 presentation about our recommendations based on our
7 experience of voltage instability in 1987.

8 Yes, I would like to focus on the Question No. 4,
9 Voltage Issues. Next, please.

10 (Slide.)

11 MR. IMAI: Tokyo Electric Power Company is the
12 largest investor-owned utility in Japan. We mainly supply
13 the electricity to the nation's capital of Tokyo, and the
14 highest demand, 64 gigawatts, was recorded two years ago.

15 Next, please.

16 (Slide.)

17 MR. IMAI: In July 1987, TEPCO experienced an
18 extensive outage caused by voltage instability, not
19 contingencies, but rapid demand increment, led to the
20 situation of no power flow situation, so no power flow
21 solution, which was voltage instability.

22 During voltage collapse, (inaudible) were
23 activated and 2.8 million customers of eight gigawatts were
24 lost. Next, please.

25 (Slide.)

1 MR. IMAI: Since then, TEPCO has enhanced power
2 transfer capability by installing numerous switches, shunt
3 capacitors of 18 gigavolts and synchronized condensers to
4 (inaudible) substations.

5 They have been planned so that the voltage
6 instability can be prevented against any single contingency
7 in summer peak conditions. If (inaudible) of regulated EHV
8 bus voltage is detected by automatic controller, they are
9 switched automatically within a few seconds, therefore,
10 TEPCO shunt capacitors can be regarded as dynamic reactive
11 power resources, because they can react rapidly enough to
12 maintain voltage during voltage collapse.

13 Next, please?

14 (Slide.)

15 MR. IMAI: Our observation on August 14 blackout:
16 We found in some sense, reactive power supply in the Midwest
17 from report. Next, please.

18 (Slide.)

19 MR. IMAI: Skip this one. That's our
20 recommendations: Number one: Install more reactive power
21 resources; No. 2, use alternative for dynamic reactive power
22 resources. Next, please.

23 (Slide.)

24 MR. IMAI: Reactive power is caused by long
25 distance for transactions, should be compensated with a

1 balance between static and dynamic characteristics following
2 NERC standards. NERC standards say reactive power resources
3 with a balance between static and dynamic characteristics
4 shall be (inaudible). Each control area shall supply
5 reactive power resources within its boundaries.

6 Each processing entity shall arrange for reactive
7 power resources. Following these standards, we recommend
8 the less expensive alternative for dynamic reactive power
9 resources, based on our experience. Next, please?

10 (Slide.)

11 MR. IMAI: And Number Two, (inaudible)
12 contingency operation like dispatching or (inaudible)
13 reduction, based on the results of (inaudible) don't seem to
14 be fast enough to prevent cascading outages because
15 corrective reactions within several seconds are needed
16 during voltage collapse.

17 Installation of more reactive power resources
18 with dynamic characteristics to EHV systems can avoid too
19 much dependence on operators against extensive voltage
20 disturbances.

21 (Inaudible) installation capacitor switched by
22 automatic controller can be reliable and economical
23 alternative for dynamic reactive power resources to regulate
24 EHV system voltage. Next, please.

25 MR. IMAI: So, we have many experience of

1 installation of (inaudible) capacitors, controllers, dynamic
2 power resources. Next, please.

3 (Slide.)

4 MR. IMAI: Conclusion: TEPCO's system has been
5 enhanced by installing switches and capacitors to EHV
6 systems, which reactors, dynamic reactive power resources
7 against voltage instability. U.S. is installing
8 interconnections may have enough room to install more shunt
9 capacitors without abating voltage collapse problems because
10 of low impedance characteristics on very (inaudible)
11 network.

12 And also have U.S. (inaudible) interconnections
13 have been operated centrally through EMS (inaudible)
14 analysis and can be more secure by using dynamic switch
15 shunt capacitors we recommend.

16 I have a feeling that the interconnections are
17 incredibly complex and very hard to operate safely. I think
18 that without (inaudible) system engineering, the
19 interconnections could have never been operated securely by
20 (inaudible).

21 (Inaudible) could contribute to make (inaudible)
22 connections more robust and secure and to avoid future
23 blackouts. Thank you for your attention.

24 MR. CAULEY: Thank you. The third speaker is Tap
25 Seppa from the Valley Group.

1 MR. SEPPA: Thank you, ladies and gentlemen. I
2 have quite a number of overheads here. I'm going through
3 them at a fast clip because there will be handouts available
4 also at the end of the presentation, and you'll see the
5 website address where you can pick up this presentation and
6 a couple of related presentations.

7 And I'll be talking only, concentrating only on
8 the Questions 3 and 7, and just to give you a summary before
9 I go through the presentation, there was some bad news: The
10 bad news was that the rating assumptions in Ohio and Indiana
11 during the day of the blackout, were totally inappropriate.

12 And furthermore, a number of utilities were using
13 sag calculation methods, which were clearly likely to
14 underestimate the sag conditions and the danger of the
15 situation. And what is evident to us is that either NERC,
16 FERC, or DOE must create mandatory procedures for
17 establishing the line ratings to prevent similar
18 occurrences.

19 And the good news comes when we talk about the
20 .7, namely, there are methods to accomplish some of these
21 procedures with moderate cost. Next one, please.

22 (Slide.)

23 MR. SEPPA: We did a study about the Ohio wind
24 conditions on 8/14 in the afternoon. And if you look at the
25 table there, that's 11 weather stations and note the number

1 of zero wind speeds that were recorded there. That
2 afternoon, there were 23 percent of the observations that
3 were zeros, which is six times more than the occurrence of
4 calm weather under normal conditions.

5 And then we took the data and we processed it
6 using what the meteorologists call a super station
7 principle. That means you aggregate the data and treat the
8 hourly observations and treat the wind directions
9 accordingly.

10 I'm sorry, can I get the next slide?

11 (Slide.)

12 MR. SEPPA: And this is the statistical wind
13 speed distribution in the afternoon, and if you note, what
14 we say is that the effective wind speed -- there was a five-
15 percent probability of the wind speed being less than 0.6
16 foot per second, and 0.6 foot is actually total calm.
17 That's when the cooling goes to the natural convection, and
18 we believe some utilities assumed 4.4 foot per second, a
19 safe wind speed.

20 You can see that that represents a 50-percent
21 probability for that day. Next overhead, please.

22 (Slide.)

23 MR. SEPPA: What are the consequences? If you
24 assume that your line is rated at 100 degrees C maximum
25 temperature and you push that accordingly, and if you get a

1 0.6 foot per second wind speed, you can see that you will
2 get between 25 and 57 degrees C higher temperature than what
3 your rating assumes, provided for, and out of the 20,000
4 miles of lines in Ohio and Indiana, about 1,000 miles, 6,000
5 spans at any time on that afternoon, were operated under
6 those assumptions. Next, please.

7 (Slide.)

8 MR. SEPPA: What does that mean for the line sag?
9 I'm not saying that there were (inaudible) there; I'm simply
10 saying that when you push you sag down, eventually you will
11 meet the tree, and you can see the consequences. Conduct
12 sag on a typical span were between two and five too much,
13 assuming that the sag calculations were correct, but knowing
14 that most utilities in the area use old sag tension methods
15 which can be up to three to five feet inaccurate, we are
16 talking about lines hanging between five and ten feet too
17 low. Next one, please.

18 (Slide.)

19 MR. SEPPA: Now, this is not unique. This could
20 have happened elsewhere.

21 21

22 22

23 23

24 24

25 25

1 The big reason is that NERC allows the
2 transmission owners to pick up whatever numbers they want.
3 They can calculate, they can assume any wind speed they
4 want, and they vary around the country from zero to six foot
5 per second.

6 They can calculate the sags whichever way they
7 want. They can even eliminate the clearance buffers from
8 their lines, if they want.

9 And the big problem is that the operators do not
10 recognize, what is the primary reason for thermal limits.
11 It's safety, public safety.

12 When lines sag into trees and you get 20 kiloamp
13 faults, fortunately, they only splinter the tree. If you it
14 sags into a school bus, you get something which is
15 equivalent to a few sticks of dynamite. Next, please.

16 (Slide.)

17 MR. SEPPA: The other thing that operators do not
18 recognize is -- and I read 640 pages of transcripts -- and
19 they do not recognize that if you have a high pre-load on
20 the line, you are starting from a point where you have
21 essentially no time to react.

22 There was operator comment that said I'll just
23 keep the line under 100 percent and not worry about it
24 anymore. Next, please.

25 (Slide.)

1 MR. SEPPA: What's the alternative? You can
2 monitor lines and there are utilities that monitor their
3 lines in real time. You know, the objective is that if you
4 look at the probability of having good cooling conditions,
5 by far, most of the time, your lines have more capability
6 than you think. That's the green area in this graph.

7 On the other hand, the red area represents times
8 like in Ohio and Indiana on 8/14. Next one, please.

9 (Slide.)

10 MR. SEPPA: The real-time monitoring provides
11 operators true real-time information, and there's an example
12 of a screen at one utility that uses systems like that. You
13 can determine the exact capability of the line that's on the
14 left side of the screen.

15 On the right side of the screen, it gives the
16 operators a clear warning. It tells the operator how much
17 the sag is compared to the limiting value, and how much time
18 he has under the current conditions to react before there is
19 a clearance violation. Next, please.

20 (Slide.)

21 MR. SEPPA: Now, really now I'm talking about the
22 Question 7. How can we deal with this with contingency
23 management?

24 In summary, what you can do is, you can assume a
25 higher wind speed or more benign overall conditions for the

1 contingencies and dispatch your system accordingly. But you
2 should do it only if you can monitor the system in real
3 time, because then the operator will get an advance warning
4 if he gets into trouble.

5 On the other hand, the vast majority of the time,
6 he will not have to do anything, and you can typically
7 increase your dispatch capabilities by 15 to 25 percent.
8 Next, please -- oh, skip all these, please.

9 (Slide.)

10 MR. SEPPA: So what must we do to avoid more
11 blackouts? Somebody must set clear procedures for
12 establishing line ratings. And it should be either NERC,
13 FERC, or DOE. I'm not saying that they should establish the
14 line ratings; they should say what is the minimum
15 information required.

16 The second one is that the operators must be
17 trained to understand the reasons behind line ratings and
18 the most important thing, the safety consequences. And,
19 yes, there should be sanctions for operational lines in
20 violation of safety codes.

21 The paradoxical thing is that a national
22 electrical safety code gives you an absolute mandate, always
23 to operate the line within safety limits, including
24 emergencies. And on the other hand, there's no -- it's like
25 you'd be saying don't drive through red lights but nobody

1 would ever stop you.

2 (Laughter.)

3 MR. SEPPA: And the operation above the
4 established limits should only be allowed if there is
5 reliable, real-time information on the lines. Next, please.

6 (Slide.)

7 MR. SEPPA: So, what do we have as alternatives
8 now? For 20 years, utilities have been relaxing the line
9 ratings, and at the same time, we are pushing the systems
10 more.

11 If you would want to get the same state of
12 reliability and safety as we were 20 years ago, we would
13 have to reduce our network throughput by about ten percent.
14 The second alternative is, of course, let's build something.
15 Now, here we are talking about a price tag of anything
16 between \$15 and \$50 billion.

17 And the third alternative is to use real-time
18 monitoring, and that can actually increase the grid
19 capability and the cost is relatively minuscule. Next one,
20 please.

21 (Slide.)

22 MR. SEPPA: Just a thought for you: The average
23 transmission line in this country now dates to roughly 1970.
24 That's like your father's Dodge.

25 And there is about ten percent of the lines which

1 predate your grandfather's Ford. Next, please.

2 (Slide.)

3 MR. SEPPA: Now, you can drive these things a few
4 minutes at 90 miles per hour, but if you do that like in
5 Ohio, the whole afternoon, the wheels will come off. And
6 there is work being done on that IEEE level, and there is a
7 new Zebra (ph.) task force. You can get information on them
8 if you go to our website, and also you can find transcripts
9 of this and a couple of other articles. Thank you.

10 MR. CAULEY: Thank you. The last two presenters
11 on this panel are working on the investigation team, and we
12 have Bob Cummings, representing the area of modeling and
13 analysis.

14 MR. CUMMINGS: Good afternoon. I'm Bob Cummings.
15 I'm the Director of Reliability Assessments and Support
16 Services for NERC. I got involved in the blackout
17 immediately, almost. I was out actually trimming my lawn,
18 but about the first beer and looking at CNN, I realized that
19 the lights were out everywhere.

20 At any rate, I've been involved with, first, the
21 sequence of events, followed by the working with the
22 modeling area and dovetailing into the planning.

23 What I'd like to talk about are some of the
24 aspects of modeling and how it relates to a few, just a few
25 of the points in this thing. Some of the things we ran into

1 immediately in trying to do the modeling was load
2 representation.

3 In the power flow base cases, we typically use --
4 we have power factors that are overly optimistic. The case
5 we picked up was a summer case at peak, and we had to
6 substantially increase the reactive loading in order to get
7 it to come anywhere near what we saw on the 14th.

8 Another one is the generation representation.
9 We've got pretty optimistic reactive capabilities, but in
10 many cases, they are unproven. They are untested; they are
11 unverified.

12 This is not new. We saw this in WSCC back in
13 '96, in '99 in the PJM area when they had some voltage
14 issues. They went back and found that their generators
15 weren't performing up to the assumptions.

16 Another issue that we came up against in now many
17 fronts, both real-time and in the post mortem analysis, was
18 line rating disagreements, not just the ratings themselves,
19 but disagreements between one operator and another.

20 And, of course, there are interchange transactions.
21 We heard some speakers earlier talking about some way of
22 getting the transactional information up to everybody for
23 analysis. That already has existed since 1997. It's called
24 tagging.

25 It's not universally used and it's not completely

1 used as well as it should be, but it can help an awful lot
2 if it's done right.

3 However, a lot of the studies we do just aren't
4 capturing the levels of transactions, and a simultaneous
5 analysis has to be done. As I mentioned, there's overly
6 optimistic power factors and incorrect circuit ratings.

7 We found issues where three operators had three
8 different ratings for the same line, one, operationally, and
9 one in a planning study and such.

10 Part of the problem with our power flow is that
11 it's never benchmarked. We don't have a feedback loop from
12 the actual system operations.

13 It has to be benchmarked back to what you can see
14 in the 115 and 161 KV systems. This includes the dynamic
15 aspects of system support.

16 If we don't do this periodically, we are just
17 fooling ourselves, because our studies will just never mimic
18 reality.

19 Other things are: Topology -- I found data
20 problems in the case we picked up for this analysis this
21 year that I first discovered in 1992, working in the ECAR
22 region, building base cases. It was the same problem. I
23 fixed it for four years running on all 15 cases that ECAR
24 built.

25 The problem is still there. What's wrong with

1 this picture? They were just never corrected. Bad
2 modeling, it can really bite you. Next one.

3 (Slide.)

4 MR. CUMMINGS: When we started in on the post
5 mortem, time synchronization of the telemetry, and all of
6 the digital fault recorders became a real nightmare. In the
7 earlier stages of the analysis, it was pretty easy. We're
8 looking at minutes in terms of between events.

9 However, when you get down into milliseconds as
10 you get into the dynamics area, this really needs to be
11 fixed. We've talked about this before in a couple of other
12 outages across the time, and synchronization has to be done
13 at the point of origin, because that's the only way you're
14 going to get them on the same basis.

15 Another problem we had was inconsistency of data
16 quality and the retention of those data. We found key bus
17 voltages missing from recordings of the system. That makes
18 it really hard to go back and try to backtrace. Next.

19 (Slide.)

20 MR. CUMMINGS: Line rating problems: As Tap was
21 just talking about, the methods of calculations, we probably
22 need some bounded parameters. We're not going to let
23 anybody give us a ten foot per second perpendicular wind
24 speed and say, oh, that's okay.

25 We also have to have some sort of quality control

1 on the ratings. What are the boundary conditions on
2 clearances?

3 On the thing that I mentioned on the disagreement
4 on ratings, we have to have some method of policing that,
5 some method of transmitting a change, even, in a rating.
6 This has to go between the planing models, the interregional
7 studies, the state estimators and the reliability
8 coordinators. Anybody using these data need to be advised
9 of any line ratings changes. Next one.

10 (Slide.)

11 MR. CUMMINGS: You need to know where you are in
12 the system. System data exchange is crucial. You need to
13 know what units are online; you need to know what
14 transmission lines are out of services.

15 We went into this when looking at the system data
16 exchange that's used by the IDC and used by some security
17 coordinators as input into their security operations, and it
18 disagreed with actual system conditions. There were
19 omissions, errors, and some non-outage elements that were
20 listed as being outage.

21 That just creates a problem; it creates
22 misunderstandings. Another thing is untimely data entry.
23 There were lines that were out of service for quite some
24 time before they ever were entered into the SDX.

25 This also is a problem of an incomplete picture.

1 Not all of the CAs and RAs are entering the data, and we're
2 starting to depend on this.

3 In the work we're doing with PJM and MISO, we're
4 asking them to update the SDX data on a cyclic basis
5 equivalent to their LMP engine calculations. This is so
6 that we make sure that we keep the IDC in lockstep with
7 their calculations.

8 Is real-time data needed here? That's the best
9 way to do it. This topology process that we talked about a
10 little earlier, maybe that needs to be what feeds the SDX
11 and the process or until such time as we can ensure that
12 everybody's got the topology process. Next.

13 (Slide.)

14 MR. CUMMINGS: Regional and interregional
15 studies: We need to take all outages, including generation,
16 into account when we're looking at things. We need to do
17 more than just N-1 contingencies. Some severe outage
18 scenarios are obviously necessary.

19 And we need to monitor the entire system, not
20 just regional interfaces. Zonal analysis: If we're just
21 looking at corporate boundaries, we're going to miss the big
22 picture of pockets of the system that regardless of
23 ownership, are going to behave the same way for certain
24 things.

25 We need to also look at a wider variety of

1 transactions, study the known patterns, analyze the
2 historical trends that are in the tags, and both magnitude
3 and the trends of transactions have to be recognized in a
4 simultaneous nature. Next one.

5 (Slide.)

6 MR. CUMMINGS: This is a cut set that we took for
7 the analysis. The orange lines are where we drew the
8 boundaries, and just to look at what was the impact of
9 transactions that day, particularly to look at what was
10 going into the ECAR, this area right in here.

11 Now, we discounted the flows coming in from this
12 side of the system because we were really interested in what
13 was coming around from the South and the West. Next slide.

14 (Slide.)

15 MR. CUMMINGS: And what we see is, from the first
16 of June through the 13th of August, was that we were,
17 indeed, that day having very heavy transactions. They
18 weren't the outer bounds of the transactions, but they
19 certainly were heavy.

20 So here we are thinking we've got heavy duty
21 transactions, but I think we were also being lulled into a
22 sense of going in the wrong direction. Next slide.

23 (Slide.)

24 MR. CUMMINGS: Some of the things you need to
25 think about in terms of simultaneous transfer studies:

1 These are some of the studies that are done. Paul mentioned
2 the MEN studies. MEN looks at simultaneous transfers and
3 the nomograms.

4 VEM looks at sensitivity studies for selected
5 transfers; MET only for the Wisconsin, upper Michigan
6 system, but a good one that was just done this past summer
7 is as a prototype was the coordination of summer
8 transmission assessment done by MISO, PJM, TVA, SOCO, AECI,
9 SPP, Entergy.

10 And it fully looked at simultaneous transfers.
11 Next slide.

12 (Slide.)

13 MR. CUMMINGS: This is one of the nomograms from
14 the MEN studies. And these two are the operating points
15 scheduled in actual, and you can see from this nomogram that
16 they're operating within the bounds of the situation for the
17 day.

18 One thing about this, though; this is not
19 something that's not necessarily immediately at the
20 fingertips or the knowledge base of the individual
21 operators. They don't have enough of the information to
22 actually put this in their hands. Next.

23 (Slide.)

24 MR. CUMMINGS: So the situational recognition is
25 important. Where are you? And what units are out? How are

1 you going to deal with your system that's in front of you?

2 These are all the other problems we've talked
3 about. Some dynamic transfers are not tagged, so you need
4 to understand that those things won't be reflected in
5 something like the IDC and in some security analyses. Next
6 slide.

7 (Slide.)

8 MR. CUMMINGS: We did some looking and seeing,
9 because our concern was, we felt that everybody thought
10 there were transactions that were causing the problems on
11 the 14th. Well, it turns out that the tag transactions only
12 played a minimal role and had a limited flow impact.

13 So here we are thinking that we've got a
14 transactional problem and in reality, what we have is a more
15 localized problem. The main contributors were flows into
16 the overloaded lines based on network loads and generation.

17 We talked about what you'd have to do in terms of
18 load shedding, 1500 megawatts when you're talking about
19 South Canton Star and 2500 megawatts by the top of the hour
20 in order to get under the system. These are boundary
21 conditions.

22 So, here we think that we're going to have to go
23 into TLR. If we go looking at trying to do a TLR, and we
24 don't think about doing immediate load shedding, we're going
25 down the wrong path. Next slide.

1 (Slide.)

2 MR. CUMMINGS: This gives you an idea of the
3 composition of the elements of what was going on on the
4 lines in particular. Of all the transactions, all the
5 different levels of transactions, you didn't really get any
6 serious relief on South Canton Star until you got out into
7 your native and network loads.

8 So, if you have this at your fingertips, you know
9 immediately that you've got to go to load shedding, that
10 transactions, going after transactions is going down the
11 wrong path. Next.

12 (Slide.)

13 MR. CUMMINGS: So just in summary, some modeling
14 improvements are needed: Load power factor, generation
15 reactive capabilities, improved topology awareness, both
16 from SDX and what's happening in transactions. Those are
17 the things that I see.

18 MR. CAULEY: Okay. Good job. And the last
19 presenter for Panel D is Frank Macedo of Hydro I, and he is
20 also one of the team leaders in the Planning and Systems
21 Study Team.

22 MR. MACEDO: Thank you, Gerry, and good
23 afternoon. My fellow panelists have covered a lot of
24 ground, and in order not to repeat very much of what has
25 been said, I'd like to focus on five key issues for

1 consideration:

2 Next slide.

3 (Slide.)

4 MR. MACEDO: There is no substitute for being
5 prepared. I think we've heard that this morning, and we've
6 got to express that. And the best way of making sure that
7 you are prepared is to carry out a full set of sensitivity
8 studies to reflect the operating conditions that are likely
9 to be encountered on the day itself.

10 N-1 contingencies, assessments of N-1
11 contingencies forecasted peak loads and known firm transfers
12 is just not enough. These studies should go way beyond that
13 minimum requirement.

14 Clearly, we ought to look at all the outages;
15 that goes without saying, but equally important is to stress
16 the system, look at loads beyond forecasts, look at
17 different import levels, look at all the transactions, and,
18 in fact, the full range of transactions that might obtain.

19 Bob talked about load power factors. That's
20 clearly extremely important, but also important is the
21 availability of the distribution capacitor banks. Don't
22 make any assumptions; study the sensitivity of different
23 power factors, particularly in the summer with air
24 conditioning load and the lower power factors that result.

25 Load representations are extremely important,

1 particularly for voltage stability studies. You need to
2 model to the best that you can, induction model loads and
3 other loads that draw on reactive power. At least look at
4 the sensitivity of those models to the performance of the
5 system.

6 Finally, you've got to look at conditions on
7 adjacent systems. You can't just focus on your own area;
8 you've got to look at how others might be affecting you, and
9 vice versa.

10 The second issue is minimum voltage criteria.
11 Voltage magnitudes alone are poor indicators of proximity to
12 voltage collapse. I can't stress that any more than that.

13 The system may be close to voltage collapse, even
14 if the voltages are near normal. The system should be
15 planned and should be operated so that there is sufficient
16 margin between the normal operating point and the point of
17 collapse.

18 And the best way to do this is to determine the
19 minimum voltage at key buses on the system. And the best
20 way of doing this is to use the traditional or the accepted
21 methods of PV/QV analyses.

22 I'm not sure how many people actually do these,
23 but I cannot recommend more strongly that these should be
24 done and these minimum voltages established.

25 Coming out of those PV/QV analyses would clearly

1 be the minimum reactive reserve requirements that must be
2 maintained in local areas to be able to respond to
3 contingencies. And I stress local areas. It's not good
4 enough to look at the overall footprint of a control area;
5 you've got to look at where the voltage collapse is likely
6 to occur, and then show that the reserves are where you need
7 the reserves.

8 And I'd recommend that the real-time monitoring
9 of these dynamic reactive reserves should also be considered
10 to ensure that the minimum requirements are met.

11 And, finally, if these minimums, minimum
12 voltages, minimum reactive requirements, cannot be met, then
13 operating strategies must be developed as a safety net.
14 These obviously include load shedding to ensure that there
15 is sufficient reserve to be able to withstand the next
16 contingency.

17 The third issue is the one that we talked about
18 this morning, and that is the 30-minute adjustment criteria.
19 I've got a different spin on this.

20 The planning criteria very clearly says that, you
21 know, after one contingency, you can manually adjust the
22 system to prepare for the next contingency. And the
23 operating policy, too, says that you've got 30 minutes to do
24 that.

25 What I'm here focusing on is really the measures

1 that are relied upon to achieve the 30-minute adjustment.
2 It's extremely important that those measures are duly
3 considered in the planning timeframe and in the operations
4 planning timeframe, and that these measures are shown to be
5 feasible, and that they are communicated to the operators
6 who are going to actually apply these measures.

7 Now, if these measures -- if we cannot -- if
8 these measures aren't available and I cannot implement them
9 in 30 minutes, then clearly the system must be operated to
10 the N-2 to be able to withstand N-2 contingencies.

11 The fourth issue is extreme contingency
12 evaluations. We heard some of this this morning, but I want
13 to stress this: The criteria requires an assessment of
14 system performance for extreme contingencies. In fact, this
15 is Category D of the NERC planning criteria.

16 Now, these are contingencies beyond the normal,
17 expected criteria, and these are things like multiple
18 outages. These assessments measure the robustness of the
19 system and they help to maintain the state of preparedness
20 to deal effectively with such events.

21 Greater emphasis must be placed on these
22 assessments to determine the impacts. And equally
23 important, the results of these assessments must be
24 communicated to all affected entities.

25 The control room operators should know the

1 results of these studies. It's just not sufficient for
2 planners to do these and keep them to themselves. You've
3 got to communicate these to all people who are likely to be
4 affected by it, so that they are prepared.

5 And, finally -- again, we talked about this this
6 morning -- we must consider safety nets such as under-
7 voltage load-shedding schemes to contain the disturbance to
8 the local area.

9 Finally, the issue on regional coordination
10 procedures: Each control area must review the results of
11 regional and interregional transfer studies and ensure that
12 these studies or their studies capture the impact of
13 external transfers and conditions on adjacent systems.

14 Again, these control areas must really
15 communicate any potential adverse impact of these others who
16 are likely to be affected. And, in fact, I'd go further
17 than this and I'd say that there should be a formal peer
18 review process, and, in fact, an approval process to ensure
19 that these systems meet performance.

20 In NPCC, we do have this process, which is
21 extremely valuable, and that is that each control area
22 carries out these studies, a full range of studies,
23 including extreme contingency studies, and presents the
24 results of these studies to other control areas as part of
25 this review process.

1 And these other control areas have a chance to
2 ask questions, to suggest further studies, to essentially
3 fully understand the impact that this one control area might
4 have on other control areas. And then they essentially sign
5 off on this and say, yes, you've done some studies, we
6 understand the impacts, great. I would really strongly
7 recommend that this sort of approach be applied much more
8 widely.

9 And just one final, in passing, if I may. The
10 other panel has talked about real-time monitoring and
11 ratings of lines and so on, and that's all good.

12 One thing I didn't hear mentioned at all was to
13 do periodic condition surveys of rights of way. You need to
14 know what the clearances are on a right of way, an annual
15 survey of the right of way to determine any obstructions,
16 any limitations on that a right of way. To me, that seems
17 to be absolutely essential. Thank you.

18 MR. CAULEY: Okay, thank you. Those were very
19 good presentations. We'll start with the panel of
20 investigators, and any comments or questions.

21 MR. MEYER: I have a question for Mr. Seppa.

22 MR. CAULEY: That is David Meyer, DOE.

23 MR. MEYER: I have heard -- perhaps this is
24 anecdotal, but I have heard reference by some people to the
25 concept that as lines heat up, that will generate a natural

1 convection process in the vicinity of the lines so that in
2 that sense, a line is at least to some degree, self-cooling.

3 And I wanted to see whether you regard that as a
4 realistic assessment, and how significant an effect is it if
5 it is real?

6 MR. SEPPA: Thank you for the question. You are
7 talking about one of the great urban myths of operations. I
8 have been a party in the working groups, actually, the
9 chairman of the working group that wrote the last IEE
10 thermal rating standard, and also I'm part of the
11 International Standards Writing Task Force to this effect.

12 And I can guarantee you that the crossover point
13 when you essentially go to natural convection only, that's
14 equivalent to only 0.6 foot per second. And exactly what
15 happens at that range of 0.5, 0.6 or 0.7, that's range.
16 It's not two foot per second. I am horrified at how often I
17 hear operators saying that, well, when you have a cut
18 conductor, you have at least two foot per second. That is
19 absolute nonsense.

20 MR. CAULEY: Any other questions? Dave Hilt?

21 MR. HILT: I want to talk just a little bit -- I
22 guess one of the things that I heard was quite a bit of
23 discussion about optimistic power factors and loads,
24 reactive capabilities of plants. I know NERC has some
25 documents talking about voltage and reactive, specifically

1 dating back into the early '90s.

2 There are data errors in the modeling details and
3 so forth. What strikes me out of that is that I kind of
4 would ask the group and the audience, in particular. It
5 seems that we're not paying enough attention to the details
6 here in terms of when it comes time to do the system
7 modeling.

8 And having been a old planner and operator and
9 many other things in my day, I'm kind of wondering, where
10 are the system planners today? I know that many companies
11 have rearranged and taken them out. Is this is an issue
12 that we need to take a look at as an industry as a whole?

13 I think I like Frank's suggestion that we
14 actually have a peer review process on some of the studies,
15 moving forward, such that there is more than just -- first
16 off, it produces some studies, and, secondly, it puts --
17 again, like we were talking with operations, it puts a
18 second set of eyes on those studies to kind of give us some
19 validity checking.

20 And I guess I'd be interested in any comments on
21 that.

22 Secondly, again, we talked about the TLR would
23 not have been effective and that only load shedding would
24 have been. This takes us back to an issue I think we
25 discussed a little bit this morning, talking about local

1 reserves and reserve stacks, those kinds of things in
2 particular areas.

3 And I was very interested in that and would be
4 interested in hearing what the panel and the audience would
5 think about what tools are needed so that operators would
6 know that they don't have the reactive or the real or
7 reactive capability in a given area to provide the relief or
8 provide the management of the system.

9 Short of load shedding, I don't know that
10 operators even know that out there today.

11 MR. CAULEY: Tom, and then we'll take some
12 questions from the audience.

13 MR. RUSNOV: I'm interested in how you monitor
14 wind speeds associated with a particular transmission line.
15 I guess in Ontario, a typical length of a 500 KV line or
16 even 230 is between 60 miles and 100 miles, if not more.

17 Some of those go through forested areas where,
18 in fact, they will be shielded, and even if you have wind
19 speeds at the tower top, it's going to be different 40 feet
20 down to make your clearances.

21 So my view of it is that it's largely a crap
22 shoot. You can have a very localized area with effectively
23 zero wind speeds or very low wind speeds and 50 feet away or
24 100 feet away, you've got three or four feet per second,
25 five feet per second. How do you deal with this?

1 MR. SEPPA: Let me respond to this: First of all,
2 you are absolutely correct, you know. Wind speed
3 measurements at a single point do not tell you very much
4 about it. They can give you statistical evidence, but they
5 will not give you real-time evidence of what's happening in
6 the line.

7 But what you can do is to use the conductor
8 itself as your measuring device, essentially using a
9 conductor as a hot wire. Remember that the local
10 temperatures don't matter; what matters is the average
11 temperature of the conductor between two dead ends, which
12 are a number of miles apart.

13 So the conductor essentially averages the
14 weather along its length, and that is the whole principle of
15 the so-called real-time monitoring.

16 MR. RUSNOV: Thank you. I thought there was too
17 much emphasis on the wind speed. That's the answer I like
18 to hear.

19 MR. CAULEY: Okay, from the audience, any
20 questions of the panel? Back there?

21 PARTICIPANT: Masur (ph.) (inaudible). Frank and
22 Bob have already listed a lot of issues, and I think there
23 is some suggestion -- have some suggestions or comments that
24 if we -- Frank had stated something about the operational
25 planning. If we can -- my thinking is that we should plan

1 -- the planning engineers should plan for the reliable
2 operation of the system.

3 That's like slightly different from what normal
4 load flow analysis -- they cannot cover all the
5 contingencies what we have already seen, so for that, we
6 need some different tools to bring in reliability. I think
7 EPRI -- we don't mention anything about the reliability
8 tools which I think EPRI was developing first (inaudible)
9 probably (inaudible) for whatever reason, and then now they
10 are working on another software.

11 Maybe they are working on something else, too, or
12 some other company, but we have to bring -- because we can
13 have N-1, N-2, all those contingencies, but still it will
14 only add to the cost. We can try to some extent to reduce
15 the cost, but bringing in the system reliability by using
16 some of the software, because they basically tried to
17 integrate the system planning, take the generation outages,
18 transmission outages, and based on that.

19 And one of the -- that's my personal experience
20 about the training. It's just my thinking that planning
21 engineers should be during some time, they should be made to
22 sit with the system operator for one week, two weeks, so
23 that they should see how the system is being operated,
24 because they can -- a planning engineer, planning ten or 20
25 years down the road, cannot visualize all the contingencies,

1 what the system operator is facing day-to-day.

2 MR. CAULEY: All right, thank you. Ray Kershaw
3 in the back, ITC?

4 MR. KERSHAW: I want to build a little bit on
5 what he said. If you suddenly go to a more stringent
6 operating criteria. And I don't say we shouldn't do that.
7 I think you have to extend it over to the planning process.

8 If, for example, ECAR were to suddenly use NPCC
9 criteria for operations, you would be doing a lot more
10 redispatching and TLRs right now. I mean, I'm not saying
11 that you don't do that, you don't go to a more strict
12 operating criteria, but you're going to have to recognize
13 that when you do that, interregional transactions are going
14 to either diminish or you're going to be doing more
15 redispatch, more LMP, and it's going to cost more.

16 And I don't know how you translate that over to a
17 planning criteria. For example, if you were to ask me, how
18 do you avoid the blackout of August 14th through planning
19 criteria, I'd say build the line.

20 I mean, that's a pretty simple answer, and I
21 can't tell you right now, how that would have happened in
22 the planning process. But had there been more stringent
23 planning criteria in ECAR, and the same transactions were
24 going on that day, there would be no blackout.

25 So if you look at what happened in 1965, there

1 was an immense increase. As a matter of fact, we're living
2 off the fat of the increase in the transmission system after
3 the New York blackout. We're still living off of that.

4 And I'm not suggesting that we go into a building
5 frenzy like we did then, but I think prudent investment and
6 perhaps even ECAR adopting more stringent criteria would be
7 a start.

8 And we're going to write -- have some written
9 comments on this, some suggestions on how to attack it.
10 It's mostly -- I won't get into it, but we're going to
11 supply some.

12 MR. CAULEY: Okay, Steve Lee, EPRI.

13 MR. LEE: I want to clarify something about EPRI.
14 Two software were mentioned, CREAM and (inaudible) by a
15 former speaker. The point is not so much which particular
16 software you use. I think planning is a science and an art.

17 One of the panelists mentioned the (inaudible)
18 sensitivity analysis, and that's very important. I think
19 it's more important to recognize that planning is the
20 probabelistic process and (inaudible) manufactures uncertain
21 and not captured by the models.

22 So, it's important to recognize that the
23 probabelistic reliability assessment, as a general term, is
24 what we really should be done. Thank you.

25 MR. CAULEY: Barry Lawson, NRECA?

1 MR. LAWSON: I want to address three broader
2 policy issues related to enforcement, compliance, and
3 audits. First, NRECA strongly supports NERC's possible
4 future role as the ERO. This is, of course, assuming that
5 the appropriate legislation is passed.

6 This would give NERC a much more effective
7 enforcement and compliance capability, especially when
8 compared to their current capabilities. This would have a
9 positive impact on system operations and reliability.

10 Second issue area: Regardless of whether
11 legislation passes, the industry needs to reevaluate its
12 spending priorities, especially in the context of our
13 restructured and more competitive wholesale energy market.
14 According to a recent EPRI report, capital expenditures for
15 transmission since the early '90s, have been flat. However,
16 O&M expenditures during that same timeframe have been
17 significantly and steadily decreasing.

18 We have heard here today and in the interim
19 report, where these O&M costs are being cut or at least some
20 of the areas where they are being cut -- personnel,
21 equipment, and EMS maintenance and upgrades, and right of
22 way maintenance for transmission.

23 While it will not be easy -- and we've danced
24 around this a lot here today -- this trend needs to be
25 reversed. There must be an increased emphasis, monetarily

1 and management-focused on reestablishing adequate and needed
2 O&M budgets.

3 Finally, there should be in the very near term
4 and periodically thereafter, a thorough and meaningful audit
5 of all control area operators, and that includes
6 approximately a dozen NRECA members, G&T cooperatives, but
7 an audit of all control area operators regarding their
8 compliance with exiting NERC operating policies and planning
9 standards.

10 And that includes any at the time recently
11 approved and implemented new reliability standards. The
12 results of these audits should be made as widely known as
13 possible.

14 If peer pressure is the primary tool we have,
15 then we should utilize it. This compliance assessment is
16 critical to understanding how well our industry is doing its
17 job of keeping the lights on. Thank you.

18 MR. CAULEY: Thank you. Jack Kerr from
19 Dominion.

20 MR. KERR: I have a recommendation related to
21 Item 3 on the agenda concerning how to ensure ratings
22 accurately reflect actual conditions. I would recommend
23 that transmission line ratings be required to be stated in
24 amps instead of MVA.

25 And that would eliminate the disconnect we have

1 between the actual voltage component of the MVA measurement
2 and the nominal voltage component of the MVA rating.

3 MR. CAULEY: Okay, Mike Pennstone, IMO. Are you
4 still with the IMO? No? Hydro I.

5 MR. PENNSTONE: Hydro I.

6 MR. CAULEY: Hydro I, I'm sorry, my mistake.
7 Mike Pennstone.

8 MR. PENNSTONE: No problem. For those of you
9 who aren't familiar with Hydro I, we're one of the licensed
10 transmitters in the Province of Ontario. Our operations are
11 directed by the IMO.

12 At the outset of this meeting, our gracious hosts
13 asked us for some advice as to what recommendations we
14 should be giving them in terms of moving forward. So in
15 return for your cup of coffee, I'll offer you a few
16 suggestions.

17 I think that actually a number of these mimic the
18 comments that the previous speaker made. One on standards:
19 We're suggesting that let's not go overboard on developing
20 all kinds of prescriptive standards.

21 I know it's awfully tempting, but our suggestion
22 would be that you consider two types of standards: One type
23 that is essential for maintaining the reliability -- real-
24 time reliability of bulk power systems, and these standards,
25 I would volunteer, could be prescribed to the industry and

1 not necessarily negotiated by the industry.

2 I'm prepared to live with those, as long as they
3 are a handful of standards, and I would remind you that
4 Moses did it with ten commandments. I would suggest an
5 equivalent number of standards would be appropriate.

6 So let's not get into standard dds for developing
7 line ratings, standards for developing vegetation
8 management; let's talk about standards in terms of complying
9 with N-1.

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1 The second set of standards would be objective
2 based. And for those of you who are unfamiliar with that
3 term, that basically says, "here's what you have to
4 accomplish." It doesn't prescribe how you're going to get
5 there.

6 So again, don't give us standards in terms of the
7 types of tools that we need, the types of state estimators,
8 the number of contingency analyses and all the rest, just
9 give us some high level objective base standards. We'll
10 follow them. Tell us to keep the rights of way clear, don't
11 tell us how many trees to cut down.

12 The purpose of those standards, unlike the
13 original set, is to basically ensure that we avoid creating
14 adverse or unsatisfactory conditions that are the precursor
15 to a blackout.

16 Vegetation management was a good example of the
17 August 14 situation -- it was the precursor. If you didn't
18 have nasty vegetation management practices you wouldn't have
19 had the blackout.

20 Secondly, I think there's a need to establish an
21 environment to ensure that there is a continued diligent
22 adherence to these key standards. January 1 is coming
23 really quickly and it would be a real shame that all of this
24 effort is the industry's equivalent to a new year's
25 resolution.

1 We do make an awful lot of promises and we're
2 going to do things right so we do do them for a short period
3 of time and then it starts to wane. And somehow, I think
4 this point was made in spades, when you talk about the
5 previous blackouts that we've experienced in North America
6 and the fact that we haven't seemed to learn from those
7 lessons and I would suggest that that environment has two
8 components -- one is a formal, rigorous licensing and
9 comprehensive monitoring of entities that contribute to
10 reliability.

11 In the Province of Ontario we are a licensed
12 transmitter. That means we have obligations to our
13 regulator. If we don't meet those regulations our license
14 gets pulled.

15 Now does that mean we take down all our towers
16 and walk away? No. But I am certain that it would have an
17 impact on our senior management.

18 It is a key consideration when we do our business
19 what those license obligations are and we make sure that we
20 follow them.

21 The second element I would suggest is that we
22 need incentives to develop and implement reliability,
23 investments and solutions. For some reason they're not
24 there.

25 Lastly, I have encouraged the industry to try to

1 identify some sets of precursors or measures by which you
2 could identify the potential deterioration in the
3 performance of entities that are responsible for
4 reliability. I think if you read the August 14 report,
5 there was enough suggestions in the practices that were
6 being followed that people should have picked up on it
7 early, come in and asked those responsible to clean up their
8 act.

9 This is not an unusual practice in our industry.
10 Within Hydro One we do this as a regular basis in terms of
11 managing our safety.

12 PARTICIPANT: (Inaudible.)

13 MR. CAULEY: Thank you. You should probably use
14 the mike ahead of time in the front. I think that one lost
15 a battery.

16 Any other comments from the audience?

17 Carson Taylor, Bonneville Power Administration?

18 MR. POWER: I would like to reinforce something
19 that Bob Cummings touched on and that's to increase the
20 comparability and interface between off line planning tools
21 and the state estimator and on line simulation.

22 For example, it would be very nice and very
23 helpful if you could take a state estimator dump and take it
24 to an off line environment and run dynamic simulations or
25 additional static simulations so every time you have a large

1 generator trip some place in the interconnection, which
2 happens about once a week or so, and that would increase the
3 data quality quite a bit. Thanks.

4 MR. CAULEY: Anything else from the audience?

5 (No response.)

6 Anything else from our panel of investigators?

7 Panel, okay?

8 All right Frank, one last comment? Frank Macedo,
9 Hydro One.

10 MR. MACEDO: Thanks Gerry.

11 Just to follow up on what Carson just mentioned.
12 I think a dump of the state estimator floor plan studies is
13 great but I'd go further than that and suggest that perhaps
14 a dump of disturbances on the system should also be used for
15 training operators, for training personnel.

16 We do this. We have a capability of doing this
17 ourselves and I sort of emphasize that, if others could do
18 it, it would certainly help. So this would dump all the
19 alarms that come up when you have a disturbance, all the
20 break offs, the whole thing and you could replay that to the
21 operators and see how they respond, of course, when they
22 recognize the situation and what actions do they take?

23 Thank you.

24 MR. CAULEY: Okay, Alison? Alison Silverstein?

25 MS. SILVERSTEIN: This is not a comment but

1 rather a request. A number of the speakers who have talked
2 today and other people whom we have heard from over the
3 course of the investigation have talked about how your
4 organizations have done lessons-learned analyses back home
5 and the wonderful things that you're doing to implement what
6 you have learned from the -- blackout in terms of improving
7 your organization's capabilities and I'm wondering if any of
8 you would be willing to share those with us within the
9 investigation and the Task Force, so if your organizations
10 have prepared reports that you are willing to make public so
11 that we can better understand what you found on your system
12 and how to make it better, I think that those would have
13 great value for us.

14 If you could share them we'd very much appreciate
15 it. I think you could submit them as part of the same
16 comment process that we're receiving -- other comments.

17 So thanks in advance and hope you send us lots.

18 MR. CAULEY: Okay, we have one more panel and
19 it's a very important one, on protection and controls and
20 how we keep blackouts and disturbances in the future from
21 spreading as widely as this one did.

22 So we'll come back in fifteen minutes, at 3:15
23 p.m. and we'll conclude with our final panel.

24 And I just want to make sure I have the
25 presentations of all the final panelists. Check with me if

1 you don't mind.

2 (A brief recess was taken.)

3 (Back on the record.)

4 MR. CAULEY: (Tape gap) in terms of generation
5 and transmission performance but I think more importantly,
6 going ahead, what can we do to better protect the system and
7 better controls to ensure that, if we do have a major
8 disturbance, how do we inhibit the progress of the blackouts
9 so we don't have a wide area cascade and we can contain it
10 into a smaller area.

11 And we'll start with Carson Taylor, Bonneville
12 Power Administration.

13 MR. TAYLOR: I'll stand up and waive my hands --
14 next slide.

15 (Slide.)

16 I'm in the middle, I guess, in this cartoon.

17 Next.

18 (Slide.)

19 What I want to talk about on the next two slides,
20 compliance with NERC planning standards which I think is a
21 fairly good description of industry best practices and we
22 really need to start to better enforce them.

23 On the voltage load shedding, zone free relays
24 has already been mentioned a few times and another
25 recommendation is prioritized control and protection

1 improvements both at generators -- probably mainly at
2 generators, and also at transmission.

3 Other things I'll talk about is coordinated
4 voltage control design, some ideas on better voltage control
5 and advanced form of capacitor bank design, special
6 protection systems and wide area measurement systems and
7 wide area control systems, automated direct load control or
8 demand side management and the main message is what we need
9 is defense in depth or multiple layers of defense.

10 We talked a lot about control center improvements
11 and this panel is about improvements in the control and
12 protection.

13 NERC planning standards, section two and three,
14 deal with modeling and control and protection.

15 Better off to read here rather than turning -- it
16 was specifically developed following the 1996 blackouts in
17 the western interconnection and approved by the NERC board
18 of trustees in 1997.

19 That's six years ago now so industry has had six
20 years to digest them and try to comply with them. As most
21 of you know that includes standards, measurements, guides
22 and later development of compliance templates.

23 There's some enforcement by NERC at the NERC
24 level of the regional consult documents such as a plan for
25 restoration by NPCC for example. It doesn't go into too

1 much detail but at least an audit that these documents and
2 plans exist. Individual regions can do further enforcement.

3 I would say WCC in particular has been proactive
4 in at least partial enforcement of these standards. There's
5 a reliability management system that is subscribed to by the
6 major utilities, I think almost all the major utilities, and
7 they in turn enforce them, enforce standards with their
8 interconnected generator companies.

9 For example, in the reliability management system
10 there is a requirement that all generators operate in
11 automatic voltage control mode -- and we do enforce that
12 with our generation companies. It's a struggle sometimes
13 but we're monitoring them.

14 Generator testing has been a major program in WCC
15 also. We spent many millions of dollars on this. Many
16 utilities have complied and a few haven't.

17 Next slide.

18 (Slide.)

19 I'll just list a few of the most interesting
20 standards here. Synchronized condensers operate in
21 automatic voltage control mode. Another standard that
22 generators shall maintain, network voltage of reactor power
23 output -- as required by the transmission system operator.

24 Next.

25 (Slide.)

1 A guide that generators and turbines shall be
2 designed and operated so there is additional reactive power
3 capability that can be used during disturbances. There's a
4 standard that voltage regulator controls and limit functions
5 shall be coordinated with the generator capabilities and the
6 protective relays.

7 Next.

8 (Slide.)

9 There's a standard on generator testing that I
10 mentioned. This has not been enforced and WCC has been
11 probably the most active in this area.

12 Also there's a guide, not a real strong statement
13 unfortunately, about zone free relays and the problem with
14 them operating on a combination of overload and low voltage.
15 Basically in my opinion relay should operate for short
16 circuits and not for overload.

17 Next.

18 (Slide.)

19 On the voltage load shedding as has been
20 mentioned quite a few times already, controls have been
21 installed by many companies, Ontario Hydro for example, was
22 mentioned and they put in a very nice scheme in the Ottawa
23 area back in the 1980s. It also included blocking of tap
24 changing on power delivery transformers coordinated under
25 voltage load shedding of capacitor bank switching and tap

1 changer blocking.

2 TVA put in a scheme, I think, in the 1980s, in
3 our load area which would have a voltage collapse with loss
4 of a 500 kV transformer. At Bonneville and Northwest
5 Utilities put in schemes in the early 1990s in Seattle and
6 then later in the Portland area.

7 In many locations this is really needed as a
8 compliment to under frequency load shedding. Sometimes you
9 need one and sometimes you need both or you need the other.

10 There's a few items mentioned but going back to
11 the bottom item, it's possible to replace the existing under
12 frequency load shedding relay with a relay, a new digital
13 relay, that does both under frequency load shedding and
14 under voltage load shedding and you need the same trip
15 circuits so it's a lower cost.

16 The thing that's important is that the
17 measurement must come from the transmission side or the
18 unregulated side, of an LTC bulk power delivery transformer.

19 You want to mention all three phases. All should
20 be depressed so you don't operate for a single phase fault.
21 Settings are generally 8 to 10 percent below the voltage
22 during heavy load which shifts from normal.

23 If you need better than this you might want to go
24 to a centralized scheme that would take additional
25 measurements such as generator reactive power output of

1 generators or remaining reactive power reserves.

2 Time delay should be fast in the -- around one
3 second in summertime cases where you have a lot of air
4 conditioning load. This was the case in the TVA insulation.

5 Next.

6 (Slide.)

7 This has been a pet topic of mine since about
8 1968 when I took a protective relaying course from Eric
9 Gross at RPI. He was involved in the 1965 blackout
10 investigation and he preached to us that relays operate for
11 short circuits not for overloads and back in 1970 I was able
12 to get EPA people to eliminate use of zone free relays which
13 is something I was proud of and surprised since I was a
14 young engineer at the time.

15 In most cases for main grid EHB transmission and
16 even 230 kV you have redundant relays. Zone free is sort of
17 a back up to a back up for very rarely occurring multi
18 phased faults not involving ground. It's not a proper way
19 to detect overload and it's not a proper way to detect out
20 of step conditions.

21 If it is needed you should look at either
22 blinders or replacement of a digital relay that you can
23 restrict the operation in the load area. This again would
24 be one area that perhaps for prioritized control and
25 protection improvements, which is the next topic.

1 Modern relays are much more reliable and higher
2 performance. It's something you can do fast and is very
3 different from building a transmission line which may take
4 many years to get approvals and money and so on.

5 For example, generators, many of the older plants
6 have 1960 vintage voltage regulators and the new digital
7 ones are much better. For example, overexcitation problems,
8 it's a smooth, almost bumpless transfer and you can
9 automatically go back and forth between fuel current control
10 and automatic voltage regulation.

11 In some cases you might want to replace the whole
12 excitation equipment including the exciter. There may be
13 substation improvements such as change of bus arrangements
14 and so on, that may also be desired.

15 Digital control and protections have better
16 facilities for built in monitoring which is very nice in
17 disturbance recreation and they should be treated just like
18 building a transmission line going to the right base so that
19 utilities have a financial incentive to pay back.

20 This a list of the four failures in the
21 Washington area interconnection and I want to just highlight
22 the generation loss. Much of this was unnecessary and
23 undesirable.

24 For example, at the August 10, there was 175
25 units with undesirable tripping. Most of them are

1 undesirable or unnecessary.

2 Next.

3 (Slide.)

4 Generators in no danger of damage have tripped
5 during cascade outages for a very long list of reasons
6 there. Most of them are electrical which means that it's
7 easy for us electrical engineers to improve.

8 The last one, boiler problems, is maybe more
9 tricky but, with digital boiler controls, it's much more
10 reliable in cases where generators are tripped because of
11 boiler problems, 15 or 20 minutes after the transience.

12 Next.

13 (Slide.)

14 This is an example of the August 10th disturbance
15 and there was an island formed in Northern California by
16 uncontrolled islanding. Initially this is a point of the
17 islanding and frequency excursion, under frequency load
18 shedding worked just like it was supposed to do, a little
19 bit of overtripping and we came back to about 50.5, about
20 one percent over frequency. Also overvoltage because of the
21 load tripping and the unloading of transmission of the inner
22 tie lines.

23 And everything came back in a couple minutes but
24 then units started tripping, two plants here are shown.

25 About three minutes after the disturbance and

1 after the successful under frequency load shedding and the
2 reasons are volts per Hertz and loss of excitation and a few
3 of the other things on the list in the previous slide.

4 They did some additional load shedding and
5 finally recovered to about 59.5 and it took them I think
6 about an hour and a half before they were able to get up to
7 60 Hertz to resynchronize with the Northwest.

8 So everything would have been much better if
9 these power plants were not tripped off line for these, I
10 think unnecessary, reasons with better control and
11 protection.

12 MR. CAULEY: (Inaudible.)

13 MR. TAYLOR: I'm not done but, okay, I'll keep
14 going fast.

15 I think there's a lot of things we can do with
16 improved voltage control. The basic idea is that
17 transmission level shunt capacitors should work in
18 conjunction with generators and stator compensators to keep
19 reactive power reserve on generators and also our line drop
20 compensation or high side voltage control, can make the
21 generator voltage control much more effective.

22 And that should be done on a much more uniform
23 basis that all generators should have coordinated voltage
24 control method. Lots of capacitor banks at BPA.

25 Next.

1 (Slide.)

2 This is a field test we did of advanced high side
3 voltage control. We switched a capacitor bank off and the
4 generator response is shown here, very much better than
5 standard terminal voltage control.

6 Another thing we've done at Bonneville is what we
7 call CABS or capacitor bank shorting, and to compensate for
8 the unstable behavior of a capacitor bank, output goes away
9 when you need it most, and so we're working with a
10 denominator.

11 Here's a picture of it where we short part of the
12 capacitor bank and we get kind of like a more static bar
13 compensator, boosted output during low voltage.

14 Next.

15 (Slide.)

16 Insulation of BPA, that was a retrofit on a 230
17 kV 168 megabar bank.

18 Next.

19 (Slide.)

20 On a modern fuseless bank, this is a 460/691
21 megabar design from an EPRI study that G-E did. TVA by the
22 way is installing some of these schemes.

23 Next.

24 (Slide.)

25 As far as special protection systems, I would

1 recommend that you put the money first into basic control
2 and protection upgrades. Control separation is difficult
3 and a mess. It can be done but it might be solving the
4 August 14 problem instead of the next problem.

5 Out of step relaying involves impedance relays
6 and you really need to carefully design any kind of control
7 separation scheme.

8 Next.

9 (Slide.)

10 Wide area measurement systems. This is something
11 with like 30 times per second data rate or 60 times per
12 second data rate. We have it in the West and the AEP, TVA,
13 Entergy and New York and maybe some other utilities are
14 looking at it in the East.

15 Next.

16 (Slide.)

17 As far as centralized wide area control system,
18 BPA is putting in a scheme called PLAX. Basically this is a
19 voltage measurements and a combination of voltage
20 measurements and generator reactor power measurements and
21 it's a flexible platform that can be used for capacitor bank
22 switching and load tripping and direct load control.

23 Next.

24 (Slide.)

25 Next.

1 (Slide.)

2 Next.

3 (Slide.)

4 That view, real time control is what we're using.

5 Next.

6 (Slide.)

7 Measurements are at a number of locations all
8 within the Northwest using BPA fiber optic communications.

9 Next.

10 (Slide.)

11 Direct load control for stability. This is
12 something that we've been promoting through a (inaudible)
13 task force. Jeff Davo was actually the head of it or was
14 the head of it. The idea is to go piggyback on the demand
15 side management or direct load control put in for other
16 reasons but to try to shed load fast and painlessly and a
17 lot of schemes a lot of capabilities of it existing such as
18 using a simple pager technology. You can get air
19 conditioners off within 10 seconds or so. PEPCO for example
20 does this or did it and I would suggest maybe automated
21 activation rather than manual activation.

22 And I think that's it so sorry I went over.

23 MR. CAULEY: Thank you Carson. I had to twist
24 Carson's arm to get him to fly all the way across the
25 country so I feel bad about moving him along but I

1 appreciate your being here, Carson.

2 Next presenter is Phil Tatro from National Grid.

3 MR. TATRO: Thank you.

4 I'd like to talk about the application of
5 protection systems within NPCC and how it relates to the
6 questions that have been raised. There's quite a few very
7 good questions, probably too many to cover in seven minutes,
8 so what I would like to do is just draw on and group some of
9 the questions together and draw up some highlights.

10 I think a lot of these questions, the answers are
11 still under investigation but, by drawing out some of the
12 critical considerations that need to be evaluated in
13 answering these questions, we can help to make sure that, as
14 the investigations go along and that the questions are
15 answered, that we've got a thorough analysis behind the
16 answers.

17 I guess I'd also point out that I think the
18 answers probably will not be one size fits all but one may
19 be correct in one system and may not work in another system.

20 Moving on, just briefly I have taken a few
21 excerpts from our MPCC book power system protection criteria
22 and right up front we state the objectives and you can see
23 where the objectives fit right in with the idea of
24 minimizing the propagation of outages, limit the severity
25 and extent of the system disturbance and then, if you do

1 have a system disturbance, you want to be able to have a
2 timely restoration so you want to limit possible damage to
3 system equipment so you can put the system back together.

4 And our guidance is from the bulk power
5 protection criteria and maintenance criteria for bulk power
6 system protection. These tend to be, these give us our
7 guidance, they're functional criteria, they're not
8 prescriptive, but they are very comprehensive and part of
9 the processes that we go through in MPCC, there's other
10 procedural documents also that govern the peer review
11 process that we have when protection systems are added to
12 the bulk power system, so that all the members of MPCC
13 review those and I think it yields a better overall product.

14 One of the, I guess it's possibly unique to MPCC
15 is that we have a functional definition of the bulk power
16 system so where we apply our bulk power system criteria is
17 based on the results of system studies.

18 I know in New England we have a 23 kV bus where a
19 single protection element failure could cause an impact
20 outside the local area. Conversely we have a 345 kV radio
21 line where an end of line fault, there's no problem with
22 delayed clearing.

23 So by having this functional definition and
24 integrating system studies into the design of the bulk power
25 system protection facilities, we are able to focus our

1 attention to the areas of the system that require the
2 greatest level of protection reliability.

3 Just a few excerpts from our criteria. There's
4 many others that we factor into the design but a couple of
5 the key ones are that all bulk power system facilities are
6 protected by two protection groups that are entirely
7 independent of each other and both capable of providing the
8 required protection function.

9 We annunciate or monitor critical system
10 functions, guard signals, cut out switches. There's
11 monitoring of the cut out switch to make sure that, when
12 maintenance is done, that systems are laced back in service.
13 Trip circuit integrity -- and I think that probably one
14 thing that's common to all protection systems is that a
15 significant number fault operations occur during testing so
16 we in our maintenance criteria we stress that the test
17 procedures have to be consistent with the design so that we
18 don't compromise the integrity of the protection systems.

19 Now everything I've talked about so far pertains
20 to how we make sure that a protection system failure does
21 not cause a widespread area outage. It think the heart of
22 the question that was put before the panel was 'can the
23 relay systems halt or arrest a cascading outage and prevent
24 a cascading outage and maintain integrity of as much of the
25 system as possible -- and I think the answer is they

1 certainly can.

2 But the design of the protection system requires
3 information from system studies about where the system is
4 likely to break up so that if you were likely to employ out
5 of step blocking, out of step tripping, that you know you're
6 doing it in the right locations and that, this is one of the
7 areas that I think might vary for different parts of the
8 interconnection.

9 I think Carson pointed out in a very tightly
10 meshed system it's going to be more difficult to identify
11 where the system is going to break up.

12 And in MPCC to date we have not employed out of
13 step tripping and blocking for this reason.

14 One of the other things that we stress in our
15 criteria is that effective system protection design requires
16 coordination among all of the engineering disciplines.
17 Planning and engineering, system studies, have to all be
18 factored into the protection system design so that
19 protection systems operate fast enough to be dependable and
20 have adequate margin to operate in a secure state and we do
21 call out in our criteria that tripping of relays should not
22 occur for stable power swings and that protection system
23 settings should not constitute a loading limitation.

24 A few of the other specific questions, one had to
25 do with underfrequency load shedding. Coincidentally MPCC

1 was in the process of reviewing our frequency load shedding
2 system prior to the blackout. We've gone ahead with trying
3 to implement some of the findings of the study but at the
4 same time we're waiting for additional analysis from the
5 blackout to decide whether any additional modifications are
6 appropriate.

7 Just a few of the high level concepts, the
8 program has to be designed for the expected magnitude of
9 generation load on balance. We use a maximum of 25 percent
10 in MPCC, 25 percent generation deficiency.

11 The load shedding must be distributed so it's
12 homogeneously applied across the system. This is especially
13 important in a mesh network where you're not certain where
14 the system's going to break apart. You want to make sure
15 that you don't end up with all the load shedding be shed in
16 one island and not in another island.

17 A significant issue with coordinating generator
18 tripping with load shedding and the other thing is that the
19 load shedding scheme is in place for conditions where the
20 system governing response is inadequate to recover the
21 system frequency.

22 The load shedding scheme is there to bring that
23 mismatch back to a point that's close enough that the system
24 governing response can recover the frequency.

25 So we view that the primary function of the load

1 shedding scheme is to arrest the frequency decay. You still
2 need the system governing response to recover the system
3 frequency and I think that's a very important issue that I
4 know it's in MPCC where we're initiating a lot more
5 investigation into this area.

6 Considerations for special protection systems,
7 not surprisingly very soon after August 14, a lot of people
8 started proposing that maybe we need more special protection
9 systems to help prevent the widespread propagation of a
10 system event such as that one and I think everyone who has
11 endorsed that idea someone else has probably identified that
12 inadvertent operation of SPSs could take the system in
13 exactly the opposite direction.

14 So I think the key is that you need to be
15 judicious about where and when you want to apply an SPS and
16 I think the first bullet is a direct quote -- if not a
17 direct quote very close to it, from our 8/11 document,
18 special protection system criteria, which you just can't
19 emphasize enough that special protection system design
20 requires coordination among system planning design
21 maintenance and the protection groups, not only for the
22 design but throughout the life of the SPS where the system
23 conditions change. You want to make sure that the SPS is
24 still going to be dependable and secure.

25 And finally there were some questions about

1 dynamic recordings and analysis of system events. I brought
2 some of the documents and procedures that we have in place.
3 One is for collection of real time data for an aerodynamic
4 analysis and that actually incorporates some of our
5 neighbors also in MAC and ECAR that we collect data, have
6 the procedure to receive data from them also.

7 And then the different task forces, task force
8 and system protection reviews of disturbances, but also task
9 force system studies has their own review process and we
10 also review protection systems as operations.

11 Time synchronization issues -- I wanted to get it
12 up here. I figured by now I'd be running out of time so I
13 didn't put too much up here. But I think what I'd really
14 like to say about this is it goes far beyond just simply
15 having synchronization on the device.

16 If a device, if a fault recorder for example
17 doesn't trigger then it doesn't matter that it's
18 synchronized. It's not producing a time stamp for the
19 event. And then the other one is that we have identified
20 some devices that have synchronization but, due to some
21 mechanical problem, the antenna, you know, has been knocked
22 over in a snowstorm or something and so when people are
23 thinking ahead to what issues need to be addressed in
24 putting a standard together, I think monitoring of the
25 synchronization signal to make sure the device is locked in

1 is important.

2 In summary I think really the -- I can't
3 emphasize enough that the effective protection system
4 design, it's a multi discipline approach and I think that
5 many of the questions that have been put before the panel
6 will require some more input from some of the ongoing system
7 studies and I hope that this discussion will help to focus
8 those studies to either focus on some of the key things that
9 need to be considered in the studies.

10 Thank you.

11 MR. CAULEY: Okay, the third panelist is Chris
12 Rousseau who is going to talk about frequency issues.

13 MR. ROUSSEAU: Good afternoon. My name is Chris
14 Rousseau from Rousseau & Asc. and OSI Soft.

15 I apologize that, for this presentation, the lack
16 of a PowerPoint we were a late addition to the schedule so
17 unfortunately you'll probably need to squint to see what I
18 have here.

19 I'd like to make a brief presentation about the
20 results of an analysis that Dr. Chuck Wells and I did based
21 on the data. In the past we've worked together analyzing
22 several outages and in looking at the August 14 one we
23 noticed some similarities to some prior outages, most
24 notably the Malaysian outage in what, 1995, I believe, and
25 the Rush Island issue in 1992.

1 Characteristic of both of those outages or
2 blackouts was low carrier frequency oscillations and we had
3 a hunch that perhaps we might look for the same pattern
4 during the August 14 blackout.

5 What we did was we took the data that was
6 provided by NERC and we later conducted our analysis using
7 data that was donated to us by a member utility from the
8 Midwest and we performed Fourier transforms on the data
9 starting from approximately the time the Eastlake generator
10 tripped.

11 What we found was, this outage much like the
12 Malaysian and Rush Island outages, showed characteristics of
13 long carried oscillations that are not present -- under
14 nominal system conditions.

15 If you take a look at the -- actually, if you
16 could scroll down please? That's the one right there.

17 I'm assuming that most people are familiar with
18 Fourier transforms but for those who are not perhaps
19 familiar with the methodology, it is a way of identifying
20 what I term "subfrequency" -- pattern data.

21 In other words, typically the normal frequency of
22 the bridge of the 60 cycles per second -- this helps
23 identify longer period oscillations, in this case,
24 oscillations from 19 through 77 minutes that may indicate
25 sort of a longer period system instability.

1 What we found and if you look at this graph here
2 you will note that the yellow lines indicate both the --
3 normal distribution of an in-control -- let me move this
4 microphone just a bit -- the normal distribution for
5 frequency error for an in-control process and so there is
6 this sort of nominal exponential error and plotted on that
7 chart you will see the frequency distribution for the August
8 14 data and, in particular, the balloons there, you will
9 notice that there are at least three distinct peaks and one,
10 the fourth peak there, at 11.3 minutes, we couldn't decide
11 whether that was a real peak or not, but you will notice at
12 least several distinct peaks that do not appear under normal
13 system conditions.

14 Comparing this to nominal system data and if you
15 will scroll down a little bit you will find it -- this in
16 particular is from the Western interconnection -- you don't
17 see quite the same pattern of data. And in fact when we did
18 a moving window Fourier transform of the data, the point at
19 which the Eastlake generator tripped, we noticed that the
20 amplitude of these peaks increased showing a problem that
21 may have in fact -- and in fact was, increasing in scale.

22 What we've been working to do over the last
23 couple of months is work with some utilities and ISOs and in
24 fact we've implemented real time Fourier transform
25 methodologies based on some of the incoming data from these

1 and fortunately -- I suppose is the appropriate term,
2 fortunately we have not seen any of the same characteristics
3 yet.

4 While it is probably not accurate to say that one
5 could have deduced the magnitude of the problem based solely
6 upon the frequency data, back casting our algorithms and
7 back casting Fourier transforms over the frequency data did
8 indicate a situation that was anomalous given the normal
9 frequency, normal system characteristics of the Eastern
10 interconnection.

11 So we're going to continue the methodology both
12 with ISOs in the Western and Eastern interconnections and
13 see if this can possibly be used as a tool in the future to
14 identify unusual system conditions.

15 Thanks very much.

16 MS. SILVERSTEIN: Sir, before you sit down would
17 you be good enough to tell us not just that this is
18 anomalous but what it means? And what is the implication of
19 this?

20 MR. ROUSSEAU: Right. You may have noticed that
21 I pointedly avoided what it means.

22 MS. SILVERSTEIN: I figured that was because you
23 were a consultant but --

24 (Laughter.)

25 MR. ROUSSEAU: Right. It's difficult to say

1 exactly what it means. It's difficult to look at this data
2 and say that, given the pattern of frequency instability
3 like we saw on August 14 that a blackout of the magnitude we
4 had would have occurred.

5 What we can say is that this type of frequency
6 instability bore similar characteristics to other outages of
7 this scale in the past. And these frequency peaks that we
8 saw are not consistent with normal Eastern and Western
9 interconnection data.

10 So by themselves looking only at the peaks one
11 may not be able to deduce that there are significant
12 frequency problems. But in back casting the data, in back
13 testing the algorithm rather and looking at the data, if one
14 were to be looking at the data in real time one might have
15 deduced that there were unusual system conditions and we
16 tested this against both the August 14 blackout and other
17 blackouts in the past.

18 And our -- you caught me on the fact that I
19 pointedly avoided saying what it meant. But what I am
20 suggesting is that it may be a useful tool for identifying
21 periods of instability in the future.

22 One of the problems during August 14 in fact was
23 that I think a lot of the participants or victims of the
24 blackout did not quite know the extent nor did they know the
25 magnitude of the problems that were occurring and so looking

1 at this data may have given them some indication of what was
2 happening.

3 MS. SILVERSTEIN: Okay but let me check a couple
4 more things with you. You cited two other major outages
5 that had this similar frequency characteristic. Have you
6 looked at other outages and found that similar frequency
7 anomalies did or did not occur? Beyond these two?

8 MR. ROUSSEAU: We have only looked at -- closely
9 examined those two because those are the only two other
10 outages for which we have -- data of sufficient quality.
11 We're planning on looking at other outages of this scale and
12 scope in the future.

13 MS. SILVERSTEIN: Okay so what you're telling us
14 is this is, there is a correlation between these three
15 outages as a function of the frequency anomaly but you are
16 not venturing whether there is a causal relationship, is
17 that correct?

18 MR. ROUSSEAU: No. In fact I don't think it is a
19 causal relationship. I think it is, I think the frequency
20 instabilities were a, certainly not a cause of the problems
21 that occur but -- an indication of their extent and
22 magnitude.

23 MS. SILVERSTEIN: Okay so you're offering this as
24 something we should pay attention to in the future to see if
25 it is a useful marker?

1 MR. ROUSSEAU: That is a fair way to put it --
2 yes. That's a good way of putting it succinctly. Something
3 that may be useful to pay attention to in the future.

4 MR. RUSNOR: I think our mandate is to see that
5 you're going to wait a long, long time before you get
6 another experience with it.

7 (Laughter.)

8 MR. ROUSSEAU: As I said, we haven't seen --
9 frequency instability of this type since August 14 and with
10 any luck we won't see it any time soon. Thank you.

11 MR. CAULEY: Thank you.

12 The fourth panelist is Tom Wiedman who is the
13 current investigation team leader for the transmission area.
14 Bob Stewart of PG&E did a wonderful job then he had a long,
15 planned vacation, so that's where he's probably still at.

16 Tom Wiedman is from ConEd and he's been in his
17 stead for the last few weeks.

18 MR. WIEDMAN: Thank you Gerry.

19 My talk is going to be kind of a summary of what
20 we've done so far and some lessons learned followed by some
21 recommendations.

22 Go ahead Gerry.

23 (Slide.)

24 This slide is organized by time frame from 15:05
25 hours Eastern Daylight Time to 16:06. It's also organized

1 by the way the lines tripped out and in blue I identify the
2 lines. I also identify that the lines tripped out primarily
3 by ground faults.

4 So one could deduce that these lines had been
5 tripping by tree contact based on the signature of the
6 faults.

7 The final two events leading out of this time
8 frame were a product of the first four events and that is
9 the outage of a substation which was caused by relay
10 actuation in a breaker failure and finally the first line
11 that tripped due to non fault conditions.

12 And this has been the doorway which opens up into
13 the future operations throughout the time period leading up
14 to the blackout.

15 As the cascade moved west and north, 138 kV lines
16 and 69 kV lines in these stars, South Canton areas, were
17 tripping on heavy power flow. We then moved into a tripping
18 of a major 345 kV transmission line and there was kind of a
19 combination of a ground fault initially and then heavy power
20 flow on the automatic reclose.

21 That brought on another trip of 138 line and
22 finally the last trip before things really accelerated and
23 that was the East Lima to Fostoria Central, a 345 kV line.
24 This line also tripped on heavy power flow and by "heavy
25 power flow" what I mean is, I'm strictly staying -- staying

1 away from saying that it exceeded emergency ratings. All I
2 will say is that it was at a flow at or above its emergency
3 rating and that the relays intended to trip for fault
4 currents actually operated for power flows.

5 The cascade then moved into Michigan. The time
6 frame compressed from 16:09 to 16:10:40, just a minute and
7 40 seconds and, in that time frame, it was characterized by
8 major interruptions between the Western side and Eastern
9 side of Michigan. These trips were started off with a trip
10 on one end of a line, the Argenta end, for both Argenta -
11 Battle Creek and Argenta - Tompkin, on a single ended trip
12 for a zone three relay, a back up relay.

13 The system condition at the time was
14 characterized by overloads, very low voltage and phase
15 angles that were widening, phase angles that were measured
16 by current legs voltage or as measured between source and
17 synch bus as measured through the digital fault recorders.

18 It is important to say that, at this point, there
19 was no dynamic instability as we would initially think there
20 would have been. It was quite interesting to see that the
21 angles were widening but it wasn't at a rate that one could
22 easily say how the system is in an unstable condition.

23 More 138 kV lines tripped in the Argenta area and
24 then finally the Hampton - Pontiac and Bedford - Jewell
25 lines tripped, which were slightly north and a little bit

1 west of the Detroit area. These lines were also
2 characterized by tripping due to overloads, low voltage and
3 widening angles, but again, not instability and it was at
4 this incident time that we theorize that synchronism was
5 then lost in the Michigan area around Detroit.

6 Okay Gerry.

7 (Slide.)

8 We then turned our attention to looking at the
9 other side of the Cleveland area corresponding to the next
10 trip which was a transmission line between Perry, Ashtabula
11 and Erie West. This line was a little more unique than the
12 other lines in that the true, the Perry substation had low
13 voltage but there was actually heavy reactive flow toward
14 the East while there was active power flow going towards the
15 west to feed the Cleveland area.

16 So again this was slightly different than the
17 other trips.

18 Our next activity is to work on the phase two
19 report, which is, would be a NERC input into the Canadian -
20 U.S. task force, as will other inputs be. Our major focus
21 is to work with the sequence of events team and the root
22 cause team, the planning and dynamics team to analyze what
23 this system performance really was during these events and
24 to try to model the actual events so that we can learn
25 something and apply that to possibly new technology and

1 lessons learned.

2 We're intending to evaluate transmission line
3 readings, impacts on this cascade, we're certainly planning
4 to incorporate the comments from this public forum and other
5 public fora, the NERC steering committees and the NERC
6 standing committees, and then to seek overall endorsement on
7 recommendations that we all come up with.

8 What have we learned so far? As I said before,
9 line trips due to faults -- trim trees or preferably remove
10 the trees from the EHV right of way.

11 Second of all, lines tripped due to low voltage.
12 Consider the use of undervoltage load shedding in
13 recognizing that it is a local solution but when taken in
14 total may serve to mitigate or slow down future cascades and
15 these undervoltage load shedding schemes should be developed
16 with standard philosophy in mind much the same as what
17 Carson had presented to us.

18 Line trips due to heavy power flow, we've
19 evaluate the need for zone three time delay tripping on EHV
20 lines -- the lesson I learned here is the need to develop
21 settings criteria that is known commonly by the planners, by
22 the operators and by the relay setters, and what is the
23 primary reason for an element to reach well beyond its
24 protected line and what can we do to bring that setting a
25 little less far out into the transmission system?

1 To tell you what -- to show you what I mean by
2 that is just a simple geometry lesson -- for those of you
3 who are unaware of how transmission line relays generally
4 work and how they can be sensitive to load, the circle
5 represents an area on a plane. It's called the impedance
6 plane. It's a way of depicting the way an impedance relay
7 will work.

8 And if a quantity of voltage divided by current,
9 which is what the relay detects, gets inside that circle
10 it's going to trip. And voltage divided by current can be -
11 - fault current but it also could easily be load current and
12 just using a mathematical manipulation, that number can also
13 be considered as the $kD(\text{squared})$ that the relay C is divided
14 by the MDA or the combination of reactive and real power --
15 the square root of that -- and also there's an angle
16 associated with that which is the arc tangent of the
17 reactive power divided by the active power.

18 And the three circles are there to indicate that
19 that is a moving point especially in situations like this
20 where the system is actually cascading.

21 Next slide.

22 (Slide.)

23 This is a little more of a combination of circles
24 that I stole out of the I triple EEE power system relay
25 committee document on relay "laudability" they call it. And

1 just to demonstrate that there's actually several regions of
2 power flow that can impinge on or get close to the tripping
3 of protected relays.

4 In the far right hand quadrant you can see when
5 power is out of the relay -- that's active power -- and
6 active bars are flowing out of the relay, that can impinge
7 on the relay and cause it to trip.

8 But equally so, if power is flowing into the
9 relay and reactive power is flowing out of the relay, which
10 is in the upper left hand quadrant, that can also cause the
11 relay to trip and remembering that equation which was
12 nothing more than V over I , voltage over current, one can
13 see how a load flow can actually get inside this relay
14 characteristic and cause the relay to trip.

15 So what can we do to, given these relay
16 characteristics, what can we do to diminish this
17 probability? I'd like to go to the slide here which is
18 again another geometry lesson but it's simply two right
19 angle triangles imposed within a circle and, if I cut the
20 one side of the triangle in half, I would cut the other side
21 of the triangle in half. That's all it is.

22 The one triangle inscribed within that circle is
23 the diameter of the circle and that in fact is the reach of
24 the relay in the fault angle in the fault direction and that
25 would be what the relay would see if the voltage divided by

1 current was actually a fault whereas in the lower or leg of
2 the transformer that is inscribed on the lowest part of that
3 circle there, cutting that in half is more like what you
4 would see in that load angle or that load ratio of the power
5 system and by cutting that leg in half that has the same
6 effect as actually doubling the amount of load current that
7 that transmission line can see before it operates for load
8 current.

9 So the focus then should then be on those
10 transmission line relays that have very sensitive settings,
11 what can we do to bring those settings more in line with
12 protecting only that line, thereby diminishing its
13 sensitivity to load current.

14 Next.

15 (Slide.)

16 Some additional lessons learned and which
17 required additional data yet the underfrequency load
18 shedding relays, coordinating with the underfrequency
19 tripping of generation. Right now we have many
20 underfrequency trips of generators that after the 1965
21 blackout probably none of that occurred. So we need to make
22 sure that our underfrequency load shedding program does
23 indeed coordinate with the underfrequency tripping of
24 generators.

25 I'd like to emphasize independent NERC and

1 regional compliance standards and measures for protection
2 systems. Let's make sure we all know what each one of us is
3 doing with regards to protection and measure that.

4 Develop standards on reporting of disturbances
5 including prescribed common reporting format -- one of the
6 problems we had not only with time synchronization was the
7 very different ways that digital devices captured the data
8 and then tried to bring all that data into one common
9 format. There's a standard for that and I triple EEE
10 standard, but I think that needs some work on it to
11 definitely bring it into an operating arena, analysis arena,
12 and I believe that effort should be going on not right after
13 a blackout but just as a constant process -- there needs to
14 be that ability to bring that data in and look at it in
15 rapid time not only for the transmission owners but for the
16 regional transmission operators as well, the reliability
17 coordinators.

18 Coordinate relay tripping with line emergency
19 capability and assure for conscribed, proper automatic
20 operation of generator excitation systems, again as Carson
21 had alluded to.

22 Finally we would capture this as the following
23 recommendations which I would sure like to get your comments
24 on and that is NERC, its regional reliability coordinators
25 need to develop protective performance criteria and

1 compliance audit standards to install undervoltage load
2 shedding throughout the Eastern interconnection to evaluate
3 line reading methodologies consistently possibly using the
4 same equations, certainly the same methodology -- identify
5 likely break points in the Eastern interconnection -- as the
6 system cascades, how likely is it that the break points are
7 the same in every event or is there a new tool that needs to
8 be developed that will identify break points as the system
9 dispatch and line outages change?

10 Develop disturbance analysis methodology across
11 the Eastern interconnection -- and finally, insist on
12 voltage support requirements for generators.

13 That's it. Thanks Gerry.

14 MR. CAULEY: I'm giving these guys a little more
15 leeway on time because they're last.

16 So the final speaker of the day is Gary Bullock
17 of TVA and he's heading up the generation performance team.

18 MR. BULLOCK: Thank you Gerry. Good evening.

19 It's actually almost evening is it not? It's
20 been a long day. The party got started at about 8:00 a.m.
21 and if you're like me, that's been a good long, hard day of
22 it.

23 I am from the South, the Tennessee Valley
24 Authority is my employer and about a week or so after the
25 event that occurred, at my boss's instruction with the

1 pleasure of NERC I joined the group and participated in the
2 fact finding teams that got started collecting some of this
3 data. It was an entering perspective on my part and then I
4 later joined the generation team effort as we concentrated
5 on the generation performance control aspects of this event,
6 but I was also associated with the other teams as everybody
7 was working in conjunction.

8 I spent a lot of time with a lot of very
9 talented, knowledgeable people both on the NERC staff, the
10 participants from FERC, as well as other industry and
11 utility volunteers, including some key manufacturers that
12 were on my team and on other teams and it was greatly
13 appreciated.

14 It's been a long but very important day for me as
15 I have been most interested in hearing some of the comments
16 and insight that your different perspectives have offered.
17 They have given me a fresh look and I hope you've had a few
18 opportunities to be challenged as well about the way you
19 think.

20 The data that I'm going to present is not so much
21 recommendations although I have a few of those that I would
22 like to leave you with at least in thought.

23 But to give you a flavor of some of the
24 interesting data that I have seen as we went through some of
25 this information, some weird and wonderful stuff as far as

1 opportunity to see it but -- challenging in terms of what do
2 we do with that in expectation for the future?

3 In summary though from a generation perspective,
4 I will point out these six things and then refer to some
5 others. The generation outage in this case did not initiate
6 the cascading event.

7 Now the second point is also true though -- there
8 were unit trips in the Cleveland area and in the vicinities
9 -- yes, they did contribute to the conditions leading up to
10 these events.

11 During the conclusion of the cascade and, as
12 David pointed out earlier this morning as if you could
13 remember from back then -- this time frame for this event
14 occurred, at the very conclusion of this cascade was
15 measured in seconds instead of in minutes and that happened
16 very fast.

17 At the conclusion the generation seemed to trip
18 into three different categories or buckets of classes of
19 failure. First of all the excitation systems were failing
20 in their overload conditions after being stressed from
21 earlier in the day or from the conditions of the moment at
22 the times of separation from the different islands as this
23 thing was breaking apart.

24 Second, plant control systems took action and/or
25 failed and resulted in the generation units tripping, for

1 those reasons as they became sensitized to some things that
2 were going on, and third is a consequence of the system
3 simply breaking apart and the units being left islanded with
4 no load reserve and disconnected from the load or
5 tremendously overwhelmed with too much load and frequencies
6 collapsing.

7 In addition to that, it is somewhat of a surprise
8 as we've walked in looking at some of this information.
9 There were some prolonged out of step conditions on the
10 system that were quite evident.

11 My conclusion, or at least my perspective, is
12 that generation performance may have expanded the boundaries
13 of the result of this blackout but I must classify "may."

14 This is almost like trying to put a pinball
15 machine and know where that little metal ball is going to
16 bounce next. It's just almost impossible as this thing
17 ended in a few seconds of collapse -- to know for certain
18 that one thing or the other could have changed the
19 consequences and the boundaries. But it's possible.

20 And I'll point out some of those.

21 Today this is a bit of a surprise as little
22 damage has been discovered as a result of this event. Now
23 that's good news -- although there may be some bad news
24 hanging in the wings as time progresses and things have been
25 stressed.

1 The first thing that I will point out related to
2 the idea that excitation systems were overloaded, everyone
3 is understanding that there was a unit that came out very
4 much earlier in the day. That's the little blue box up there
5 close to the light. You see that it's in the vicinity of
6 Cleveland -- that is Eastlake Five.

7 Go to the next chart and you will find that this
8 indicates the performance of that unit through out the
9 morning and at the moment of very trip you can see that the
10 purple curve right there at the top where the reactive
11 output of the unit had just increased -- that was an
12 operator action because of the times of stress, the voltage
13 was fallen at the time and he was taking action at,
14 instruction from, the control center to try to support
15 voltage more.

16 And then the total collapse of the reactive
17 output as an excitation trip -- not trip but delimiter, had
18 taken place and tripped off of automatic to manual mode and
19 then, within four and a half minutes of the operators trying
20 to restore that reactive support, the unit trips completely
21 off as the excitation system simply fails.

22 Now, from this point on through the day as,
23 without this unit, of course, there is even more stress on
24 the -- trying to maintain the voltage in the area -- and
25 there are other units that are also stressed and they go

1 through this same sequence of tripping the excitation system
2 but not completely off. They then cool off and they ramp
3 back up and they'll only be tripped again and there's
4 indication of all of that.

5 All this points to the fact that there was no
6 margin in the area where the generators were trying to hold
7 the voltage up. They were operating at their maximum.

8 As the cascade actually starts to happen, this
9 not obvious from the chart in terms of the color that I
10 chose -- red, and red is a poor choice for the little
11 circles, but you see a point here at Avon Lake and there's
12 some Burker units and there's a Morgan unit that is an IPP
13 in the central part -- all of these transpired within a
14 short time period right before the central lines right here
15 began to operate, trip off, that Tom had referred to a
16 little bit earlier ago.

17 And they came off for different varied reasons.
18 It wasn't one common mode of failure although they were
19 related to performance of the units under stress of local
20 pitched conditions in an area that had already been
21 compromised by lack of sufficient transmission and local
22 generation to support the voltages in that area.

23 The Avon Lake unit for example, five seconds
24 before, and this kind of alludes to a comment made earlier
25 about the need for collecting data and have systems to

1 collect data for validation after a fact but we've had to
2 piece some of this together -- I have a DFR shot from five
3 seconds before Avon Lake tripping -- it shows the local
4 voltages around 76 percent and had been that way for several
5 seconds to a minute at least.

6 And so under those stressful conditions the
7 excitation system tripped off with the Avon Lake.

8 If it's followed a couple of seconds later in
9 this area here with the Burker units, they're all connected
10 at 138 kV up into the Cleveland area -- and that comes off
11 comparable in terms of it's voltage related but it's not
12 because the excitation system fails at the Burker units,
13 it's because similar to what Tom was describing, the lines
14 actually trip on zone three as the low voltage condition
15 contributes to getting into the characteristic of those
16 protection schemes with the low voltage in the Cleveland
17 area -- and the Burker units find themselves islanded with
18 no load at all so they have to trip off.

19 The Kinder-Morgan units which are located right
20 there in the central part, and they're significant because
21 the very next event that's occurring is the tripping of
22 these lines across the state, so all of these things are
23 adding steam to an already hot condition, you might say,
24 that resulted in those lines tripping in subsequent --
25 further promotion of the cascade as this is occurring.

1 The -- I think Gerry's trying to hurry me up here
2 -- that tripped on a different load altogether. There's an
3 apparent fault in the generation of the Burker transformer
4 but there's no reported damage to that transformer so it's
5 probably related to the undervoltage condition, the high
6 current levels, the harmonics that might be generated under
7 that circumstance -- there's an MCV unit that's in the
8 Northern part of Michigan also involved with all that. And
9 it's in a category of the plant going to the next slide --

10 (Slide.)

11 -- you'll see the red curve indicates -- next
12 slide --

13 (Slide.)

14 -- red curve indicates the power output. It's a
15 combined cycle plant with 12 combustion turbines and a steam
16 turbine that is recovering the waste heat from those -- that
17 unit, the steam turbine is what trips. It was an implant
18 steam system trip that let the unit ramp down over time but
19 it was jostled out of operation by the earlier Central Ohio
20 trips as it's coming down.

21 So those are definite classes of interruption.
22 Any one of these having not occurred would have slowed down
23 -- I don't think it would have stopped this cascade -- but
24 it would certainly have slowed it down, and it would have
25 occurred differently than it did.

1 Go to the next slide.

2 (Slide.)

3 There's a couple of opportunities, windows of
4 opportunities -- those are the two circles there at the
5 Michigan - Ontario border and, thanks to the good, good
6 planning and provisions by the Hydro One organization with
7 recorders that record disturbances in a high frequency rate,
8 we have some pretty good data from those two locations and
9 their windows into looking into Michigan -- go to the next
10 shot --

11 (Slide.)

12 -- and you see a time value plot. During the
13 16:10:40 time period and you see a very interesting look at
14 the blue plot right here. And what you see is, this is
15 nominal voltage coming across -- it's a little bit low.
16 This is on the 230 kV and it's right at the interface with
17 Detroit.

18 And here is a voltage suppression that is just
19 phenomenal when you see that. You note that it occurs for
20 almost a second.

21 Now this is an angular instability and at the
22 very trough of that right there is where the Toledo -
23 Cleveland island actually separates off into an island and
24 it is dropped off the connection into the Eastern
25 interconnect and, likewise, the voltage recovers. It's

1 followed immediately by these two notches right there and if
2 you study through that what you'd see is, that's classically
3 a unit going out of step -- but it's not a unit.

4 In this case it's a collection of units, probably
5 about 3,000 to 3,500 megawatts of units in that region that
6 are pulling out of synch with the rest of the Eastern
7 interconnect and that's why it's so severe -- is the 230
8 voltage impacted.

9 That's followed immediately by a little saddle
10 that then results in two more troughs -- what are those? Do
11 they have a different signature?

12 One of them is an acceleration. The first two
13 troughs are an acceleration as the units pull out of synch
14 and race ahead and then trip themselves.

15 The other two are a de-acceleration, something I
16 would not expect to see. In fact there are several things
17 here that we were never expecting to see. This is as
18 frequency is dropping and, if you compare the frequencies
19 here you find that you may have gone as high as 62 Hertz
20 and, by this time period, it's all down to about 58 Hertz.

21 So there's a period right here of a few seconds
22 for which the system is given a real ride.

23 If you go on to the next shot --

24 (Slide.)

25 -- and that first one was a concentration of the

1 time value plot of data looking in from this Southern
2 connection in Detroit. The second one here is the Northern
3 section looking into Detroit from the Northern side of the
4 window of opportunity there with these good recorders there
5 from the Hydro One system.

6 In this case this is an impedance block and for
7 those of you who are used to or you've seen some of the
8 impedance characteristics of plots dealing from a static
9 standpoint, this is a dynamic plot of that. This looks like
10 something that one of my young engineers might have played
11 around with a transient stability case and made something
12 look funny by doing something weird on the system.

13 But this is live, real time data.

14 Now the color code on all of this is such that
15 each change of color is approximately two seconds there. So
16 you see how this goes about. And it's a really wild tornado
17 of a roller coaster.

18 What is happening in this area, that is when the
19 Cleveland and Toledo island is removed -- it's the trough of
20 that very low voltage that you saw and things look like they
21 might recover -- except look at the shape of this.

22 And you see that's the classic out of step
23 condition as that circular swing is going out there and then
24 there's a discontinuity right here. This is as several of
25 the generators in the Southern Detroit area are pulling

1 loose -- excuse me, this is the Northern Detroit area that
2 are pulling loose.

3 And one of these units is actually recorded as
4 being tripped on an out of step condition -- other tripped
5 for a different mode of operation because they don't have
6 out of step tripping protection on them.

7 And then you get into this wild circle right
8 here. Next shot please.

9 (Slide.)

10 This is one of the first things that we saw from
11 these recorders and this wild operation right here -- we
12 thought there was something wrong with the data, something
13 was wrong with that recorder -- that can't be. The system
14 can't oscillate that fast.

15 And then we think, no this is some unit that
16 pulled out of step and they're racing ahead and they're on
17 overspeed but that would mean that it gets to 150 percent
18 overspeed. Nothing came apart. So that's not the case.

19 This is an underfrequency condition. These are
20 units in the Southern Detroit area that have been left on --
21 left electrically connected to the system but they are out
22 of step and they are decaying in frequency and it's beating
23 against the remaining system as that's happening.

24 Next shot please?

25 (Slide.)

1 Several weeks after this event -- six weeks to be
2 exact, and then subsequently several weeks after that, a
3 report came out on the Italian blackout that occurred on
4 September 28. And this was probably -- many people didn't
5 pay much attention to this frequency, increasing frequency
6 oscillation that you see there, but it really stood out to
7 me because I had just seen that in the plots that we were
8 looking at from our exam.

9 It looks like this is a common theme that you
10 need to be cautious about in terms of expecting if your
11 protecting generators are trying to protect systems with
12 generators on them, it looks like from one side of the
13 world, from the New World to the Old World -- this could be
14 a common area of a problem.

15 That chart was by the way borrowed from that
16 Italian report in English.

17 Next shot.

18 (Slide.)

19 Some of the low frequency conditions that we're
20 talking about, the dotted line and the dashed line right
21 there are a perfect 60 Hertz cycle and you can see that
22 that's not a peak to peak condition there as you're looking
23 at the top as a voltage.

24 And you can see the current is following in a
25 very erratic nature as this is still connected to the 60

1 Hertz system yet it's operating in this case at 38 Hertz.
2 This is a recording that at Brownstown, which is in the
3 Downriver Detroit area. It's on the 345 kV. It's directly
4 connected to a pretty large coal plant and a very large
5 thermonuclear plant -- which are the two traces of current
6 flowing there.

7 Nest shot.

8 (Slide.)

9 This one now is the same location but you see the
10 characteristic and again the dashed line and the dotted line
11 are a perfect 60 Hertz cycle -- this is operating at 24
12 Hertz at this point and there are other shots that are
13 recorded as low as 23 Hertz as this is the units -- stay
14 energized, they stay connected.

15 What's happening here? Are you familiar with the
16 sequential scheme of tripping where the generation
17 protection engineer is concentrating on an introspective
18 protection of his plant with the idea that the system is
19 going to be the system that's always going to be there. I'm
20 perfecting my plant and I wish to trip the unit off with the
21 load very low on the unit so I'm going to use reverse power
22 and trip the generator breakers on reverse power.

23 But wait, that really may not operate, so I'll
24 put a redundant one in. That sort of -- scheme can be
25 thought of but what happens if there is no reverse power?

1 And in this case there wouldn't be because it's running
2 asynchronously. It already pulled out of step before the
3 reverse power could ever occur and it's decaying with local
4 loads still connected being subjected to this frequency as
5 well.

6 Next shot.

7 (Slide.)

8 This is a Fourier transform. Carson talked about
9 earlier about doing some Fourier analysis and we did some
10 Fourier analyses of those oscillograph shots -- and what you
11 see here is a 60 Hz signal that's obviously there at the
12 particular round sound but the overbearing part of that is a
13 46 Hz -- the next trace is a 38 Hz which is about seven
14 seconds later, and then that's followed with three shots in
15 a row that are about two or three seconds apart in the
16 16:11:45 and nine time period that are in the 26, 24 and 23
17 Hz time frame -- and then we stopped getting traces as these
18 units finally get removed from service -- but not by
19 underfrequency load protection or underfrequency generation,
20 protection -- not by volt per Hertz for whatever reason that
21 didn't occur, not by reverse power -- but by inadvertent
22 energization as they finally get slow enough and the voltage
23 gets slow enough that the units trip off for those reasons.

24 So this was not expected by anyone trying to
25 coordinate the protection for the units.

1 So there's the limit frequency condition that you
2 weren't expecting. Next shot please.

3 (Slide.)

4 The rest of the system, while this was going on,
5 is also -- because you can see that, while this is going on,
6 that's this portion right here, all that dirty looking
7 oscillation that's bleeding -- yet there is another
8 phenomenon going on that's an excessively high frequency
9 condition that was also going on impacting generation
10 performance and protection in that area.

11 As you see the frequency escaped to 63 Hz twice
12 in short order in the Southern Ontario region as well as the
13 upper New York State area. And the response of a typical
14 unit can be seen on the next shot which is a red curve --
15 there shows the power output from one of the large nuclear
16 plants on the lake there in the New York area -- this one
17 makes it -- this one almost hangs in there.

18 The first roller coaster ride that it gets when
19 it gets to 63 Hz, the unit, there's a natural reduction in
20 electrical output as it's getting accelerated and it does a
21 ramp down like it's supposed to do to try to curb the
22 frequency that's out right now at 63 Hz.

23 After that is recovered it starts to go back to
24 normal. It was probably on its way to maybe a recovery but
25 bang, this is a one-two punch.

1 Tyson is in the ring and look out, here comes the
2 second shot. And there's another 63 Hz and it does it one
3 more time.

4 You know, it may have done it -- it may still
5 have recovered but the design engineers for this plant never
6 really expected to have to go through this and, by now, it's
7 out of hydraulic control fluid pressure so the unit has to
8 trip for those reasons.

9 And all of these are to be expected. The unit
10 has to protect itself and that's the reason why this comes
11 off, drops of and, at this point in time gets a reverse
12 power and that opens right there the generator breaker.

13 Now this time, this works, unlike what's
14 happening to Detroit right here, this is how this is planned
15 to work -- and it does work here because the frequency is
16 still approximately 60 Hz at this point in time which is
17 acceptable for that to operate and the unit never pulled out
18 of synch -- but it could have been a different story.

19 Well, I tried to make this presentation sort of
20 simple, tell you what I was going to tell you, tell you and
21 now I'm telling you again what I told you. So again my
22 conclusions here were pretty obvious. The generation
23 outages did not initiate the cascade this time.

24 This all works coordinated together, transmission
25 generation, even customer load on the demand side and it

1 could have been any one of these elements that could have
2 initiated this as it failed and the system is no longer
3 adequate to get supply to a particular area and there are
4 all kinds of conditions that relate to this but I wanted to
5 leave you with the idea -- and this will be my last shot,
6 Gerry, so you can blink it as you need to --

7 (Slide)

8 -- to expect the unexpected. We need to get in
9 the mode of doing that. Earlier in the presentations that
10 were presented and the comments made from the audience there
11 was some discussion about involving different people in the
12 evaluation. When the other blackouts have occurred and when
13 this blackout had occurred there were a lot of people from
14 planning and operations that get involved -- where are the
15 designers in this?

16 The designers need to see some parts like this
17 and be involved in this and it's a good opportunity for
18 them, as well as -- to make any headway in this there are
19 going to be some costs associated with that.

20 Tom challenged us with that in terms of go the
21 distance, fight the fight that needs to be fought to get
22 these things in front of the right people to make and stress
23 the point.

24 I want to leave you with this thought. I am very
25 pleased at my own personal physician does not measure my

1 health by counting the number of heart attacks that I've
2 had. And I think we need to get out of the mode of counting
3 the number of blackouts that we've had or the number of
4 times that a unit has had to be tripped by a blackout
5 scenario, that we need to look at some of these other
6 indicators and several references have been made to that and
7 I think there's opportunity for a lot of different ideas to
8 address that -- to address the health of the system.

9 Even down to if it's a simple matter of doing the
10 generation testing that was referenced earlier. Phil made a
11 comment to the fact that, in doing some of the testing you
12 tripped off some of the units. Well, that's an indication
13 you've actually found out something good. That wasn't
14 something bad.

15 You found out that unit has a limitation and it's
16 time to address that.

17 Thank you for your time. I'm sorry if I got too
18 excited or too long winded here.

19 MR. CAULEY: Thank you all the panelists.

20 We'll open it up to questions from our
21 investigating leaders. And we'll start with Alison
22 Silverstein.

23 MS. SILVERSTEIN: I have a question for Mr.
24 Taylor and Mr. Tatro, but the first is, verify for me that
25 modern DFRs have GPS time synch capabilities built into them

1 please?

2 MR. TAYLOR: It's whatever you specify when you
3 buy the equipment. Are you asking about voltage regulators?

4 MS. SILVERSTEIN: Well, everybody who has talked
5 today has taken shots at the need for time synchronization.
6 And I just want -- and one of the most important and widely
7 found pieces of equipment on the system is the breaker and
8 most of these breakers and most of this equipment have DFRs
9 on them and you all are telling us we need to modernize the
10 equipment that's out on the grid so part of my question is,
11 if we go about buying modern breakers and modern DFRs are
12 they going to have GPS in them? Are we killing two birds
13 with one stone by doing that?

14 MR. TATRO: I certainly think that what Carson
15 said, that if you specify that that's what you want on the
16 digital fault recorder that's what you'll get. One of the
17 side issues that I pointed out was that you have to select
18 what's going to trigger the digital fault recorder to
19 activate and start recording due to storage limitations and
20 the amount of data that's collected, you set the trigger to
21 respond to an event and start recording.

22 And so that's one of the items I think that also
23 needs to be discussed further -- are the traditional
24 triggers that we use adequate because we certainly had line
25 trips where digital fault recorders did not trigger.

1 So even if you had the synchronization there's no
2 time stamp and no recording created.

3 MS. SILVERSTEIN: Thank you.

4 Mr. Tatro, you were talking about your definition
5 of bulk power system facilities. As you add new facilities
6 onto your system do you find that the facilities that meet
7 that definition of the bulk power system facility changed?

8 MR. TATRO: Yes. Over time we're finding that as
9 the system becomes tied more tightly together that more of
10 our 115 kV facilities are starting to meet the definition
11 and I think that I had alluded earlier that we even have
12 some cases where a 20 or 23 kV bus meets the definition.

13 But there is a trend and actually it's
14 interesting because I think the trend reflects two things.
15 I think (1) it reflects the system being tied tighter
16 together and (2) I also think it reflects a trend in better
17 analysis tools and greater computing capability that allow
18 us to simulate many more contingencies so that we're
19 starting to find certain parts of the system that -- who
20 knows? Maybe they've been a bulk power system for longer
21 than we've thought.

22 But we routinely do studies and we keep on top on
23 this and that's the trend that we're seeing.

24 MS. SILVERSTEIN: So you both have a more -- a
25 potentially more connected system but you also have a better

1 tool to discover that it's more connected, yes?

2 MR. TATRO: Yes.

3 MS. SILVERSTEIN: And Mr. Rousseau, would you
4 clarify for me -- my recollection is that Rush Island was
5 not an outage per se -- I mean, nobody actually sat around
6 in the dark after that. It was just a sort of frequency
7 thing that happened, is that correct?

8 MR. ROUSSEAU: That is correct, yes.

9 MS. SILVERSTEIN: Thank you.

10 MR. CAULEY: Any more questions by the
11 investigative leads? Dave Hilt?

12 MR. HILT: Just one comment -- when I look at --
13 and this goes back to planning groups a little bit
14 (inaudible) --

15 MR. CAULEY: Could you come up to the microphone
16 a little bit?

17 MR. HILT: Yes -- it's on.

18 I said, as I look at some of this data and I see
19 the things that have taken place here, I want to go back to
20 the planning group just a little bit. I know they're not up
21 there but certainly as I look at the number of lines that
22 tripped here, and we talked about $N - 1$ and $N - 2$
23 conditions, but certainly there were many, many lines that
24 were out of service as we went into this thing.

25 Secondly I look at some of the data that Gary

1 just presented showing some of the really incredible things
2 that happened to generation systems out there, I think it's
3 a testament to how robust this particular system is and -- I
4 think we need as an industry to think about maintaining that
5 robustness in the system.

6 Because if we can have -- we talked a little bit
7 about operating systems closer to the edge and so forth, if
8 we can still have this kind of a blackout with a system
9 that's this robust, I think we really do need to take a hard
10 look at our planning and operating criteria and make sure
11 that we maintain that level of reliability.

12 And maybe the N - 1 criteria isn't adequate and
13 we need to very seriously consider what we really need to do
14 to make sure that we don't have these blackouts in the
15 future.

16 MR. CAULEY: Anything else Dave or Tom?

17 Okay and from the audience? Any questions or
18 comments? Frank? Frank Macedo, Hydro One? I'm starting to
19 learn the difference between IMO and Hydro One.

20 MR. MACEDO: That's okay, thank you.

21 Alison, the bus system disturbance recorder that
22 we talked about that we installed two years ago, are time
23 synchronized, and they proved invaluable in this in
24 investigating the blackout and I strongly recommend that we
25 deploy such devices much wider across interconnections.

1 On the frequency spectrum analysis that you've
2 done. I'm intrigued by the notion that the frequency
3 spectrum can give you a -- can be a precursor to problems
4 down the road. I would have thought that you needed to go
5 much further than that and actually model, produce a
6 frequency domain model of -- use that data to produce a
7 frequency domain model and determine the damping factors and
8 monitor the damping -- when the damping gets to near zero,
9 then you've got a problem.

10 So you've got a long way to go. I mean, just
11 looking at the frequency spectrum is, to my view, not very
12 helpful.

13 MR. ROUSSEAU: If I can respond to that -- yes,
14 it's a fair comment and it's clearly the frequency analysis
15 that is not the only bit of analysis that should be done.
16 But we think that it's part of a complete, one portion of a
17 complete set of analyses that should be done that would give
18 you an indication of the health of the system.

19 But an analysis that has a strong correlation
20 with -- that could be a strongly correlated precursor of
21 system problems.

22 MR. CAULEY: Gary? Gary Bullock?

23 MR. BULLOCK: I almost hesitate to do this but
24 Gerry, can you put up that other point that I left you in my
25 folder?

1 And Chris, I apologize because I didn't have the
2 opportunity do discuss with you earlier. My VP had given me
3 that report as he got copy of it and the recommendations of
4 the work that you all had done.

5 And we need to be about looking at ideas like
6 this in terms of getting indicators that can give us some
7 heads up.

8 What Gerry's about to put up, I got curious with
9 respect to the approach that Dr. Wells and Chris had taken
10 and emulated the same kind of analysis using data that was
11 in TVA's archives so I took liberty last evening in fact to
12 take a look at the frequency spectrum for the 14th and I
13 came up with slightly different peaks there but they're in
14 the vicinity of what you had accomplished and I had a
15 different set of data that had more continuity to it than
16 what you had available by using the scanned in data and
17 digitized approach.

18 (Slide.)

19 Gerry, I need your assistance and go back to the
20 chart that is on the tab back up before that.

21 (Slide.)

22 This is the 14th. But I got interested in, well,
23 how does it compare with other days? I took four other
24 samples and what you see here is a collection -- it's going
25 to be busy but what you see is August 13th as well as 14th,

1 as well as September 1st and September 13th and 14th.

2 And I found that there was one day, the little
3 blue curve, happened to be very passive. But the other days
4 were even more active than the 14th.

5 And I did see a pattern and I think it's
6 significant. That's the reason why I bring it out here.

7 You'll note there that the period is very close
8 to the first peak there -- is about 120 minutes. That's two
9 hours.

10 The second one there is a period that comes to
11 approximately one hour -- I mean, it's 57.8 minutes or
12 something like that.

13 The third one is 30 minutes. And I'll get to a
14 point here -- you'll see a 15 minute and a 10 minute period
15 there and my experience after looking and being sensitized
16 to looking at frequency excursion on the system as we were
17 trying to do some of the earlier fact finding team work, was
18 trying to get a calibration point, and what I was seeing,
19 and I think other operators have seen this too, that around
20 the top of the hour and the bottom of the hour, frequencies
21 are taking an excursion.

22 And I think what you're seeing there is a fault
23 signal of not an oscillation that's fundamental on the
24 system, but an operator controlled or lack of operator
25 controlled -- signal. As we're trying to meet all of these

1 very large schedules and moving the schedules around, and
2 our, the players in this environment now also have some
3 inexperience in doing that and we've got a little growing
4 and a little maturing and a little better control issues to
5 take place.

6 And that's what I gathered out of that.

7 But I thought the initiative to go look at things
8 like that was very important so I commend you and Dr. Wells
9 for starting and leading me off in looking at some of this.

10 It probably needs more evaluation like another 50
11 days worth of studies on this side of things, but it's a
12 good approach.

13 That's the important thing that I wanted to bring
14 out. Thank you.

15 MS. SILVERSTEIN: So Gary, what you're saying is,
16 if your interpretation is correct, this represents a better
17 management opportunity in terms of how scheduling and unit
18 ramping is occurring, correct?

19 MR. BULLOCK: Yes.

20 MS. SILVERSTEIN: Thank you.

21 MR. CAULEY: Anything else from the audience?
22 Carson? Carson Taylor?

23 MR. TAYLOR: I'd like to make a couple -- two
24 comments. Alison asked about DBR, DFR and I thought she
25 said AVR.

1 DFR I think is fairly common to have, almost
2 universal to have, some kind of time synchronization. But
3 that brings up the question, what about power plant
4 equipment and AVRs should also have time synchronization so
5 you know if an overexcitation limiter operation occurs and
6 so on. And I think that's largely missing.

7 The second comment I wanted to make was, maybe we
8 should try to consider the effective reliability on when you
9 have say a 500 kV grid, the impact of operating 115 kV lines
10 radially instead of in parallel with the high voltage and
11 that might be interesting to look at.

12 MR. CAULEY: Okay. Seeing no other hands what I'm
13 going to do is turn it back over to our distinguished
14 electricity system working group co-chairs for any closing
15 comments and hopefully congratulating our panelists for fine
16 presentations.

17 MR. MEYER: I think it has been a very productive
18 discussion and so I thank the panelists on both the current
19 panel and the previous panelists for their contributions.

20 Collectively there is a lot of effort that's gone
21 in to producing discussion that we've heard and I think it's
22 been very useful.

23 Thank you.

24 MS. SILVERSTEIN: I've learned a great deal. I
25 thank all of you for the trouble you've gone through to

1 think through and share with us your recommendations. I am
2 quite excited and daunted by the challenge of taking all the
3 good ideas that you've given us and putting them into a set
4 of recommendations that will achieve all of our mutual goals
5 which are that we have fewer such blackouts in the future
6 and run a more reliable system for the people whom we serve.

7 So thank you very much for your contributions.

8 MR. RUSNOR: I want to echo the comments from
9 David and Alison. I found them very useful and interesting
10 and again I add my congratulations to everyone who
11 participated including those from the audience.

12 This morning first thing I mentioned that we will
13 have sessions, similar but hopefully not exactly the same as
14 this in Toronto on January 9. I mentioned that what I would
15 like to do with that is to make it complimentary to today's
16 session rather than duplicate some of the areas.

17 So how are we going to do that? I'd like your
18 suggestions of areas where you want to drill down deeper. I
19 think it's probably -- maybe I won't speak for my
20 colleagues, but to include so many of the items that have
21 been discussed here today in the recommendations of the
22 final report is probably not practical.

23 So how do we encompass the principles and the
24 ideas that we have heard here, together with some policy
25 issues, into a concrete and useful set of recommendations?

1 So if we're offering you another day to come
2 together with us and to drill deeper in some areas and
3 perhaps even go beyond what the topics are -- have been
4 discussed today -- to make it more useful in developing
5 recommendations.

6 Do we want to address from your perspective
7 solutions that could be implemented in six months? In a
8 year? In two years? Do we want to identify those and be
9 more specific in them?

10 What I'm asking for is what are the actionable
11 items coming out of this session?

12 We plan to have break out sessions of these five
13 topics and potentially another topic or two depending on
14 your sense of it and I'd like to see your comments and
15 recommendations and I hope we have your participation on
16 January 9 so we're still open to suggestions on what would
17 be most useful to you because the ultimate end result of the
18 study is going to impact on all of you and your companies
19 and your operations.

20 So thank you and I really do hope that you will
21 take some time and address your comment to either the DOE
22 website or the NERC website which you are hopefully aware
23 of.

24 Thank you.

25 MR. CAULEY: Okay, thank you all for being here.

1 And that concludes the session today, thank you.

2 (Whereupon the proceeding adjourned at 5:00 p.m.)

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