ORIGINAL

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

Title: BRIEFING ON ELECTRIC GRID RELIABILITY - PUBLIC MEETING

Location: Rockville, Maryland

Date: Wednesday, April 23, 1997

Pages: 1 - 121

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Washington, D.C. 20005
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CERTIFICATE

This is to certify that the attached description of a meeting of the U.S. Nuclear Regulatory Commission entitled:

TITLE OF MEETING: BRIEFING ON ELECTRIC GRID RELIABILITY - PUBLIC MEETING

PLACE OF MEETING: Rockville, Maryland

DATE OF MEETING: Wednesday, April 23, 1997

was held as herein appears, is a true and accurate record of the meeting, and that this is the original transcript thereof taken stenographically by me, thereafter reduced to typewriting by me or under the direction of the court reporting company

Transcriber: Jody Goettlich

Reporter: Jody Goettlich

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1 UNITED STATES OF AMERICA

2 NUCLEAR REGULATORY COMMISSION

3 ***

4 BRIEFING ON ELECTRIC GRID RELIABILITY

5 ***

6 PUBLIC MEETING

7 ***

8

9 Nuclear Regulatory Commission

10 One White Flint North

11 Rockville, Maryland

12 Wednesday, April 23, 1997

13

14 The Commission met in open session, pursuant to

15 notice, at 1:30 p.m., Shirley A. Jackson, Chairman,

16 presiding.

17 COMMISSIONERS PRESENT:

18 SHIRLEY A. JACKSON, Chairman of the Commission

19 KENNETH C. ROGERS, Commissioner

20 GRETA J. DICUS, Commissioner

21 NILS J. DIAZ, Commissioner

22 EDWARD McGAFFIGAN, JR., Commissioner

23

24

25

1 STAFF AND PRESENTERS SEATED AT THE COMMISSION TABLE:
2 JOHN C. HOYLE, Secretary
3 KAREN CYR, General Counsel
4 DAVID MEYER, Electricity Team Leader, Office of
5 Policy & International Affairs, Department of
6 Energy
7 DENNIS EYRE, Executive Director, Western Systems
8 Coordinating Council
9 ERLE NYE, President and Chief Executive, Texas
10 Utilities Company
11 JOSEPH CALLAN, EDO
12 ASHOK THADANI, Associate Director for Inspection
13 and Technical Assessment, NRR
14 RONALDO JENKINS, Electrical Engineering Branch,
15 NRR
16 MARY WEGNER, Reactor Systems Engineer, AEOD
17 DENWOOD ROSS, Director, AEOD
18 ROBERT WOLFF, Chief Executive, New England Power
19 Pool
20 MICHEHL GENT, President, North American Electric
21 Reliability Council
22 JOSE DELGADO, Director of Electric System
23 Operations, Wisconsin Electric Company
24
25

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

2 [1:30 p.m.]

3 CHAIRMAN JACKSON: Good afternoon, ladies and
4 gentlemen, this meeting is the first of two Commission
5 meetings dealing with electric utility deregulation and
6 related issues. This first meeting will focus on electric
7 grid reliability and how it may be impacted by electric
8 utility restructuring -- deregulation and restructuring.
9 The second meeting will address deregulation
10 issues in general with representatives from several federal
11 agencies involved.
12 The Commission will hear presentations today from
13 both the NRC staff and invited industry representatives,
14 along with a representative from the Department of Energy,
15 I'm told.
16 Specifically at this first meeting, the Office for
17 the Analysis and Evaluation of Operational Data, or AEOD,
18 will present information from its study of grid performance
19 factors. The study was initiated to collect operating
20 experience where grid disturbances had an impact on nuclear
21 power plants and other background information on grid
22 performance.
23 Last year, two electrical disturbances within a
24 five-week period on the western grid caused 190 plants to
25 trip off line, including several nuclear units.

1 These events occurred after AEOD had released its
2 draft report -- after it had released its draft report
3 concluding that the grids are basically stable.
4 A stable and reliable grid was an assumption in
5 the NRC's report on unresolved safety issue A-44, the
6 evaluation of station blackout accidents at nuclear power
7 plants dated June 1988.
8 The reliability of off-site power is important to
9 nuclear safety since accident sequences initiated by loss of
10 off-site power are important contributors to risk for many
11 nuclear plants.
12 The Office of Nuclear Reactor Regulation also will
13 address licensing requirements for electric power systems,
14 station blackout, and potential safety concerns with recent
15 grid events.
16 The Commission understands that grid reliability
17 is a voluntary function under the North American Electric
18 Reliability Council and the regional councils, and that
19 federal oversight is currently located at the Federal Energy
20 Regulatory Commission and at the Department of Energy.
21 DOE has created a working advisory committee on
22 the reliability of the U.S. electric system, which is
23 considering whether efforts to date to maintain reliability
24 are sufficient to provide assurance of reliability in the
25 future and whether there may be a need for increased federal

1 authority over reliability in the future.

2 NRC, we understand, has been coordinating with DOE

3 and will continue to keep abreast of this effort. This is a

4 long introduction.

5 Following the NRC staff presentation, industry

6 representatives chosen to represent several different

7 geographical areas and grids will discuss the strengths and

8 vulnerabilities of their grids.

9 Additionally, a representative from the DOE will

10 describe the department's current activities regarding

11 electric grid reliability.

12 And so the Commission is interested in a number of

13 things and I'll tell you a few.

14 First, insight on what effects electric utility

15 deregulation will have on grid reliability as far as we

16 understand, a discussion of the independent system operator

17 concept, and an assessment of what governments or

18 operational specifications need to be built into the ISO

19 process to ensure a stable grid.

20 I personally have discussed the issue of electric

21 grid reliability with numerous utility executives over the

22 past year. It was not possible to invite to the panel today

23 all of the industry representatives who have been active on

24 this issue, so I apologize to you in advance. But if there

25 is, toward the end of the meeting time, I may invite other

1 utility or state representatives to offer any additional
2 brief comments they would have to the Commission as
3 appropriate.
4 I understand that copies of the various -- the
5 presentation, at least the staff's, is available at the
6 entrance to the meeting, and so unless there are any further
7 comments, Mr. Callan, please proceed.
8 MR. CALLAN: Thank you, Chairman, and good
9 afternoon, commissioners. WITH me at the table are Dr.
10 Denwood Ross, the director of AEOD, and to his right, Mary
11 Wegner, who is a reactor systems specialist who works for
12 Dr. Ross in AEOD. To my left is Ashok Thadani, who is an
13 associate director in the Office of Nuclear Reactor
14 Regulation, and to his left is Ronaldo Jenkins, an
15 electrical engineer who works for Mr. Thadani.
16 Chairman, you've covered all the points I was
17 going to make in my preamble, so I will at this point turn
18 the discussion over to Dr. Ross who will begin the
19 presentation.
20 DR. ROSS: If we go to slide 2, the reliability of
21 the grid to which the nuclear plant is connected can affect
22 the safe operation of the plant. And because of several
23 events on grids around the country, AEOD performed a study
24 which is the basis for the first part of this Commission
25 briefing and Mary Wegner is the author of that study.

1 The study identified several grid performance
2 factors, such as demand growth, capacity margin, and plant
3 age, which she will talk about. And on the basis of this
4 study, AEOD developed a recommendation that all licensees
5 should confirm and maintain their licensing basis with
6 respect to stability.
7 Mary will discuss her study in more detail, and
8 then following that, NRR will discuss the original licensing
9 basis concept and NRR's plans for addressing grid
10 reliability. Mr. Jenkins will provide the NRR comments,
11 along with Mr. Thadani.
12 Slide 3.
13 CHAIRMAN JACKSON: And before you go, in terms of
14 the recommendation from this study for licensees to confirm
15 and maintain their licensing basis, I think the memo you
16 sent also states that several licensees reviewed their grid
17 analyses. Was this voluntary on their part?
18 DR. ROSS: Yes. In fact, Mary will have the
19 specific discussion on that point. Sometimes it was in
20 response to an event, such as the Virgil summer event
21 prompted a Virgil summer reconsideration, but I think we'll
22 discuss that in more detail in the middle of her
23 presentation. But I'm not aware of any regulatory
24 requirement that dictated or required reexamination of it.
25 Now, it is true that this concept is embedded in

1 their 5054 letters that went out last year with respect to
2 licensing basis in general, of which this is just a part.
3 CHAIRMAN JACKSON: Now, are you going to talk
4 about agency actions that are generic -- any generic agency
5 actions that came about as a result of the summer event you
6 mentioned at the summer plant?
7 DR. ROSS: I don't think we were.
8 MS. WEGNER: The only action I know of was the
9 issuance of an information notice and that led to another
10 utility doing --
11 DR. ROSS: But I don't believe there are a
12 specific licensing action if that's the question.
13 CHAIRMAN JACKSON: Okay. Even though at the time,
14 the FSAR stated for that plant that the grid should be able
15 to absorb the loss of a generating unit, but in that
16 particular case, it couldn't and 16 other units tripped off
17 line. You didn't feel that any --
18 DR. ROSS: Let me check.
19 MR. THADANI: I think my understanding also is
20 that, as you say, an information notice was issued as a
21 result. Any other actions we may have taken, I don't know
22 of, but we can check on that.
23 DR. ROSS: Slide 3. Certainly, reliable power is
24 needed for safety equipment, and we see this at several
25 places in the Commission's regulations.

1 For example, GDC-17 has the notion or the idea
2 that an off-site electric power system shall be provided to
3 permit functioning of structure systems and components
4 important to safety.
5 It has a number of statements and provisions
6 relative to off-site power as well as on-site power.
7 Further, GDC-35 states that for ECCS, system
8 safety function must be accomplished using the off-site
9 electrical power system assuming the on-site power system is
10 not available, and conversely, and also, assuming a single
11 failure.
12 And other rules have links to off-site power. For
13 example, 10 CFR 50.63, loss of all AC, has requirements
14 linked to the expected frequency and loss of off-site power
15 and duration of the loss.
16 Risk assessments also considered a loss of off-
17 site power, and if in the modeling you also lose the on-
18 site power from the emergency diesels, you would be in a
19 condition referred to as station blackout, or SBO.
20 This event in many risk assessments is the
21 dominant contributor to core damage frequency.
22 At present, the contribution of grid reliability
23 to loss of station power is relatively small and it's more
24 likely the origin of loss of station power would be within
25 the station, sometimes called plant centered, such as a

1 circuit breaker or transformer faults, or weather related,
2 such as winter ice storms, strong winds, possibly an
3 earthquake, and Hurricane Andrew is a good example of a
4 weather-related loss of station power.
5 And from this you can see that adequate safety is
6 based on a combination of both, on site and off-site power.
7 And while at present, grid reliability is not a dominant
8 contributor to the risk factor such as core damage
9 frequency, it seemed important to us to provide assurance
10 that this would continue to be the case in the future
11 consistent with the licensing basis.
12 What I want to do now is turn over a discussion of
13 the grid performance factor study to Mary Wegner.
14 CHAIRMAN JACKSON: Let me just ask you a couple
15 questions before you do.
16 Do we have confidence that the assumptions
17 supporting the station blackout rule remain valid in light
18 of some of the more recent data? And what would be the
19 significance if such events -- the loss of off-site power
20 were more frequent that what had been assumed at the time?
21 DR. ROSS: From what we've seen -- we don't have a
22 published study -- that the frequency, especially related to
23 grid stability and loss of station power, is less.
24 Now, I'd say the definitive study is in a NUREG-
25 1032 which is good up to 1985. It's a 20-year study from, I

1 think, 1966 through '85, and it counts the number of events
2 and categorizes them into the three bins that I mentioned,
3 which is grid centered, plant centered, and weather, severe
4 weather.
5 We are in the process of updating that study, so
6 we will have a new Sub 1 or Rev 1 to 1032. Actually, it
7 will have a different number.
8 There was about, I think, 12 grid stability events
9 at the time of that study, but most of them were in the
10 Florida Peninsula area and it was a hardware alignment
11 situation which was corrected and there's been essentially
12 no subsequent grid centered -- or grid stability problems
13 because of the way they rearranged their interties.
14 So from what we can tell, the data would support a
15 lower frequency of occurrence.
16 Now, what we would have to do is put in the
17 duration, which is part of the blackout rule also.
18 The other half of your question would deal with
19 the reliability of on-site facilities. AEOD just finished a
20 publication on that study, almost all the diesels in all the
21 plants, and it showed in general that the reliability is
22 tracking about what it was assumed to be, and there is a
23 statistical spread. And I think we have made this available
24 to the Commission.
25 We don't have any information now that would put

1 50.63 in a new and different light, but we are working on
2 it.
3 CHAIRMAN JACKSON: Do we require a certain
4 reliability of on-site power sources that is referenced to
5 assumptions about the grid?
6 MR. THADANI: In most cases, as a result of the
7 station blackout rule requirements, licensees came in and
8 make certain commitments about reliability of on-site AC
9 power source. In this case, it might be diesel generators.
10 So we do have licensee commitments on site, AC power source
11 reliability.
12 If I may just add to it --
13 CHAIRMAN JACKSON: I guess what I'm -- let me just
14 ask you this. Are they referenced to assumptions about the
15 duration --
16 MR. THADANI: Yes.
17 CHAIRMAN JACKSON: -- and the extent of the loss?
18 MR. THADANI: In fact, I was going to touch on
19 that. That's exactly the issue, is the station blackout
20 rule, the real controlling factors are not just the
21 frequencies themselves, loss of off-site power, but also
22 duration.
23 Duration is a very critical issue, and in many
24 cases, the resolution on a plant-specific basis was that
25 they could cope with station blackout for a certain time

1 period. In most cases, it was on the order of four hours,
2 because the expectation was that off-site power could be
3 recovered during that time period.
4 And there are a number of -- as you noted in your
5 introduction, that this rule went into effect in 1988, and a
6 number of issues have developed in the intervening years.
7 Dr. Ross mentioned the IPEs are showing station
8 blackout to be still a dominant contributor, and in some
9 cases it's quite significant still.
10 And there have been some new issues that have
11 developed over the last eight or nine years, one of which
12 has to do with the behavior of reactor pump seals, and their
13 performance could be significantly degraded in the absence
14 of cooling to the pump seals.
15 What we're doing in the Office of Nuclear Reactor
16 Regulation is we are collecting and looking at all the new
17 information, grid reliability being one of the issues. We
18 are collecting all the information and we're planning to
19 reassess the whole issue of station blackout, integrating
20 all this new knowledge that we have now, and would expect to
21 complete that evaluation by the end of 1998.
22 That was going to be Mr. Ronaldo Jenkins' -- part
23 of his presentation, so excuse me for having -- I think it's
24 important to recognize that we're trying to integrate all
25 these issues and reevaluate station --

1 CHAIRMAN JACKSON: So we'll wait.

2 DR. ROSS: I think many of the commitments are
3 found in the companion reg guide to the blackout rule, which
4 is -- Mary.

5 MS. WEGNER: Slide 4, please.

6 In 1989, an event occurred at the Virgil summer
7 nuclear plant that resulted in a major grid disturbance.
8 AEOD began an inquiry to identify other grid-related events
9 that impacted the operations of nuclear plants, naturally
10 the availability of off-site power.

11 It was necessary to learn about the grid in order
12 to evaluate the findings of the study and to communicate
13 them. My presentation is divided into three parts. First I
14 will address the organization of the North American Electric
15 Reliability Council and some important characteristics of
16 the grid.

17 Secondly, I will describe some events involving
18 grid perturbations or the potential for a grid instability.

19 Finally, I will close with the conclusions I have
20 drawn.

21 Slide 5, please. The North American Electric
22 Reliability Council was formed in 1968. Its mission is to
23 promote the reliability of the electricity supply for North
24 America. It is made up of ten regional councils and one
25 affiliate council. The local utility is connected to other

1 utilities in its reliability council and to other
2 reliability councils which form the North American Electric
3 Reliability Council.
4 The entire Continental United States, most of
5 Canada, and part of Mexico are interconnected in order to
6 provide reliable electric power to consumers.
7 Membership in the regional councils is voluntary
8 and is open to all individual electric systems from all
9 ownership segments of the electricity supply industry.
10 This map shows the location of each reliability
11 council. The acronym and the names of the councils are
12 listed in the study.
13 In 1997, adherence to the North American Electric
14 Reliability Council standards was made mandatory. Each
15 reliability council has a set of operating criteria that
16 were based upon the North American Electric Reliability
17 Council criteria, but modified to allow for regional
18 differences.
19 The operation of each reliability council is not
20 uniform, that is, the Mid-Atlantic Area Council operates as
21 a single entity, while the Southeastern Reliability Council
22 is composed of four subregions which are virtually
23 autonomous.
24 Slide 6, please.
25 CHAIRMAN JACKSON: When you said that the

1 adherence to the operational requirements was made
2 mandatory, made mandatory by whom?
3 MS. WEGNER: The board of trustees of the North
4 American Electric Reliability Council, and I believe the
5 members have completed their voting on the acceptance of it.
6 But Mr. Gent could answer more detailed questions on that
7 than I could.
8 CHAIRMAN JACKSON: Mr.?
9 MS. WEGNER: Gent of the North American Electric
10 Reliability Council.
11 COMMISSIONER ROGERS: Just before we go on, does
12 every electric generator or generator of electricity for
13 sale belong to an electric reliability council?
14 MS. WEGNER: I would say probably not since it's a
15 voluntary organization, but I would say most of them do, if
16 they wanted to be interconnected to other utilities to
17 provide their electricity to others and to receive aid from
18 them when they need more additional power. There's nothing
19 requiring them to be.
20 MR. JENKINS: Independent power producers would
21 not fall under this. This was mainly for utilities.
22 MS. WEGNER: Well, they can. It's voluntary.
23 CHAIRMAN JACKSON: So membership is voluntary?
24 MS. WEGNER: Yes.
25 CHAIRMAN JACKSON: But decisions are binding on

1 the members, provided the members accept them?

2 MS. WEGNER: I presume. Mr. Gent can answer the

3 question more adequately, that there are business contracts

4 written up to enforce these decisions.

5 CHAIRMAN JACKSON: Okay.

6 MS. WEGNER: Peak demand and capacity margin

7 projections are important grid parameters. On this chart,

8 the peak demand projections for the Mid-Atlantic Area

9 Council, our council, are shown in the upper left-hand

10 graph. The lower left-hand graph shows the peak demand

11 projections for the New England Region of the Northeast

12 Power Coordinating Council.

13 All reliability councils project a yearly increase

14 in peak demand over the next ten years from about 1 percent

15 to about 2 percent per year.

16 Capacity margin is a planner's tool to deal with

17 unexpectedly high demand, demand forecast error, and so

18 forth. Capacity margin projections for the Mid-Atlantic

19 Area Council are shown in the upper right-hand graph.

20 Capacity margins for the New England Council -- the New

21 England region of the Northeast Power Coordinating Council

22 are shown in the lower right-hand graph.

23 System response to a developing situation is

24 affected in part by the availability of unloaded generation.

25 Unloaded generation is related to capacity margin. A

1 continuing decrease in capacity margin will eventually
2 impact system response.
3 Slide 7, please. Power plants are aging. The
4 plants that are expected to produce the electricity needed
5 during the 1997-2005 period have already been built. The
6 chart shows the total numbers of plants started up and their
7 total capacity by decades. Both the number of plants coming
8 on line and their capacity declined sharply after the 1970s.
9 40 percent of the electricity is generated by
10 plants which may be 26 years old or older. According to the
11 East Central Area Reliability Coordination Agreement, ECAR,
12 the aging of generating capacity necessitates the increased
13 maintenance and lengthened outages.
14 The Virgil Summer 1989 events report named the age
15 of nearby plants as a contributing factor. Age has the
16 potential to become a factor in grid reliability.
17 Slide 8, please. I have talked about the
18 organization of the North American Electric Reliability
19 Council and some characteristics of the grid. Now I will
20 address some operational aspects of the grid as demonstrated
21 during events.
22 There are two kinds of grid emergencies. The
23 first is the outcome of excess demand. That is, demand
24 above expected peak demand that may exceed reserves. As
25 this kind of emergency develops, there is usually time for

1 human intervention to mitigate the transient.

2 The second emergency type develops very rapidly as

3 a result of a fault. Automatic systems protection must cope

4 with the situation.

5 The third type of situation is a discovery of the

6 potential for grid instability due to an existing nuclear

7 plant condition.

8 Slide 9, please.

9 CHAIRMAN JACKSON: I'm looking at the fault issue

10 with the summer event, and particularly the western grid

11 disturbance of last year, and I recall that your draft

12 report at that time concluded reliability just weeks before

13 this western grid disturbance --

14 MS. WEGNER: Yes.

15 CHAIRMAN JACKSON: -- on August 10th.

16 Now, had that report specifically looked at the

17 potential of the kind of fault that caused those two events,

18 that caused the western grid disturbance?

19 MS. WEGNER: There were previous faults, the July

20 2nd one, the December 14th, 1994 in which a seemingly

21 innocuous situation occurred far across the country from the

22 nuclear plants and caused a disturbance, and I looked at it

23 to the point in which I determined to the best of my ability

24 what transpired during these events and wrote them up in

25 technical review reports, and they were summarized in the

1 report.

2 That is, I believe, as far as I could say that we

3 have reviewed the events, but --

4 CHAIRMAN JACKSON: I guess I'm really more

5 interested not so much in ringing your bell relative to that

6 particular event, but more to understand is whether the way

7 we track the status of the grid was such or is now such that

8 we would be sensitive to the potential for the kind of event

9 that occurred last summer.

10 DR. ROSS: Other than expose what happened in the

11 reports, I'm not sure of any specific action --

12 CHAIRMAN JACKSON: I guess I'm saying, what do you

13 measure to make a conclusion that a grid is stable and

14 reliable? What do you measure? What do you look at? How

15 do you reach that conclusion?

16 DR. ROSS: Okay, I understand your question now.

17 The specific event, and I think Mary's going to get bottled

18 -- segmented the western area to a number of little ad hoc

19 islands, and within the islands, certain actions took place.

20 And if the plant -- some of them tripped, most of

21 them tripped, some did not -- it was such that you still

22 have reliable off-site power to the plant, even though the

23 plant may trip, then I think that's relevant.

24 CHAIRMAN JACKSON: I guess I'm wondering, are we

25 sensitive to whether there may be operational conditions

1 that are occurring, or do we know enough even about the
2 maintenance of the grid to know whether the loading -- or
3 whatever factors, to know when a potentially problematic
4 situation is developing?
5 MS. WEGNER: That, I believe, would be DOE's
6 Office of Emergency Management's job.
7 CHAIRMAN JACKSON: Okay. And I guess this goes
8 back again to something we had talked about in an earlier
9 stage, and the issue becomes then the interface.
10 If DOE's Office of Emergency Management -- and
11 we're going to hear from them -- tracks certain things, what
12 communication is there then to us that we fold into in any
13 kind of a trending database that would trigger us to be more
14 sensitive or transmit information to the regions, to have
15 our folks be more sensitive to the potential for some --
16 MS. WEGNER: DOE has been sending me weekly
17 reports, which I've been transmitting to a number of people
18 in DOE and NRR, discussing a potential situation in a few
19 weeks in areas where there may be problems or where there
20 have been problems.
21 Don't know about any databases other than the
22 study --
23 CHAIRMAN JACKSON: But nothing that would allow
24 any response on a real-time basis or anything that
25 approaches that?

1 MR. CALLAN: Chairman, I think in all candor, I'm
2 speaking as an ex-regional administrator, the insights the
3 region gets regarding grid reliability they get from
4 industry sources, typically through the resident inspectors
5 who are -- attend several operational meetings every day
6 that the licensee holds at site.
7 But we don't have a mechanism, a reliable
8 mechanism internally to disseminate that kind of
9 information.
10 DR. ROSS: And I think also to the point we talked
11 about, the sudden, rather than the slow drop in capacity.
12 There's some inner workings amongst the councils about how
13 to, given a trauma of some sort, to separate into islands,
14 and we don't review that. We don't have access or --
15 CHAIRMAN JACKSON: You have the issue of sudden
16 disturbances.
17 DR. ROSS: Yeah.
18 CHAIRMAN JACKSON: And then you have the issue of
19 degraded voltage, right?
20 DR. ROSS: Right.
21 CHAIRMAN JACKSON: And I noted that your report,
22 and I'm going to quote from it in discussing a particular
23 plant that had a degraded voltage event stated, that "the
24 degraded voltage analysis accepted by the NRC in 1979 was
25 not updated because no requirement for periodic update

1 existed."

2 And so what's the status with respect to that? Do
3 licensees adequately monitor degraded voltage concerns, if
4 the licensee's data is updated with respect to that when
5 they perform their IPEs or their PRAs now?

6 And I guess my -- I'm told that degraded voltage
7 weaknesses were routinely identified when we did these
8 electrical system SSFIs some years ago. What staff actions
9 came out of those and do we have any current concerns?

10 DR. ROSS: Let me answer the first part and I'll
11 turn to Mr. Thadani for the second part. We don't know the
12 extent to which utilities have updated their stability,
13 hence our recommendation. We just don't know.

14 As far as what came out of the SSFIs, I'll ask Mr.
15 Thadani to answer, but I'll expect we're into the plant
16 centered rather than the grid centered area now.

17 MR. THADANI: Yes. By and large, the findings
18 were more on plant-centered issues and there were follow-on
19 activities as a result of that. But two parts. Let me go
20 back to this point to a question you raised.

21 IPEs are -- at least it's my view that they do not
22 look at degraded conditions. They look at failures, actual
23 experiential database, and that's how they come up with
24 frequencies of events.

25 In addition to that, Mr. Jenkins will be talking

1 about an effort that we're initiating at Oak Ridge National
2 Laboratory, and one element of that is going to be -- focus
3 attention on the issue you raised just now.
4 CHAIRMAN JACKSON: I keep coming to Mr. Jenkins.
5 DR. ROSS: He's the last speaker so we're all --
6 CHAIRMAN JACKSON: I will try to be good for the
7 next three minutes.
8 MS. WEGNER: Slide 9, please.
9 The first example is an event in which weather-
10 driven excess demand affected grid operations locally. The
11 event occurred on January 18th through 20th, 1994. Cold
12 weather affected most of the Midwest, south, northeast, and
13 Mid-Atlantic areas of the United States. The figure shows
14 the relationship of temperature at the Washington National
15 Airport to electricity demand for the region.
16 On the 18th in the Mid-Atlantic area, the
17 temperature began to drop from 35 degrees Fahrenheit at 5
18 a.m. to 8 degrees Fahrenheit at midnight. In the evening,
19 electricity demand increased inversely with the temperature
20 when it was expected to drop with the change in usage from
21 commercial to residential.
22 Weather conditions not only increased customer
23 load, but also disrupted fuel supplies. Generation was
24 increased to the maximum. Transmission lines were loaded to
25 their maximum.

1 Slide 10, please. Emergency measures for reducing
2 the load as shown on slide 10 were instituted. The Mid-
3 Atlantic Area Council and Virginia Power had to resort to
4 rotating blackouts to maintain the reliability of the grid.
5 Florida, New York and Canada provided power to the Mid-
6 Atlantic. Load reduction measures as shown in slide 10 were
7 instituted and utilities, government entities, the business
8 community, and the private sector all cooperated to reduce
9 load.
10 The system frequency never decreased to the point
11 where step 8, actuation of automatic underfrequency load
12 shedding relays occurred.
13 The second kind of emergency, a fault driven
14 transient, occurred in 1989 at the Virgil Summer Nuclear
15 Plant. At Virgil Summer, a loss of cooling signal was
16 generated, the turbine tripped, and the reactors scrammed.
17 Nearby plants attempted to make up the load but tripped
18 because their generator protection was set high because of
19 their age.
20 A cascading failure resulted during which 16 units
21 tripped off line and caused a severely depressed voltage
22 throughout South Carolina and the neighboring states.
23 Virgil Summer's 20 buses saw the degraded grid
24 condition and isolated from the grid. The emergency diesel
25 generators started and loaded the running buses. They ran

1 for one hour and 35 minutes. Subsequently, the licensee
2 determined that his grid analyses had to be periodically
3 updated.
4 Slide 11, please. Another important event was the
5 western grid disturbance of August 10, 1996. The weather in
6 Los Angeles was hot. Relatively inexpensive hydropower was
7 available from the northwest. Large amounts of power were
8 flowing southward when voltage problems in the northwest
9 became evident.
10 A line sagged into a tree at Oregon. Lines
11 tripped; generating plants tripped. The system separated
12 into four islands as shown on the slide outlined in heavy
13 black lines.
14 Frequency in the Northern California island
15 dropped. All five sets of load shedding relays actuated
16 causing about 50 percent of Northern California load to be
17 shed.
18 Many power plants tripped, including Diablo Canyon
19 units 1 and 2-- units 1 and 2. Southern California, Arizona
20 and New Mexico were part of the southern island. Frequency
21 dropped there also, triggering load shedding.
22 Palo Verde units 1 and 3 in the southern island
23 tripped. Neither nuclear site lost all off-site power as a
24 result of the event. A transient resulted in the loss of
25 over 30,000 megawatts of load, 25,000 megawatts of

1 generation, and the tripping of 190 generating units shown
2 in dots on the slide, which came from the western grid
3 disturbance report of WSCC.
4 Included in those dots are the Diablo Canyon units
5 in California and the Palo Verde units in Arizona. The
6 Western Systems Coordinating Council concluded that the
7 system operation was not in compliance with WSCC minimum
8 operating criteria prior to the beginning of the transient.
9 That criteria requires that the system be operated
10 so that cascading failures which can cause system collapse
11 do not occur. Cascading failures did occur. However, the
12 structure of the system and the responses of the operators
13 controlled the situation to prevent grid collapse and
14 equipment damage, allowing rapid recovery.
15 Besides events, several potential grid
16 instabilities based on licensees' analyses have been
17 reported. For example, the licensees for Point Beach units
18 1 and 2 in Kewaunee have identified scenarios involving
19 transmission line outages with the potential to cause loss
20 of all off-site power to Kewaunee.
21 Slide 12, please. My conclusions are these. On
22 the whole, the grid is stable and reliable, even in the face
23 of events as serious as the August 10 disturbance. However,
24 problems described in the study, including decreased
25 capacity margin, plant aging, reanalyses which have

1 identified problems, actual events, and uncertainties
2 introduced by restructuring of the electric industry,
3 indicate the need to monitor grid conditions on a regular
4 basis.
5 And that's the end of my presentation.
6 COMMISSIONER DIAZ: Are you sure on the Palo Verde
7 trip?
8 MS. WEGNER: I'm sorry, sir.
9 COMMISSIONER DIAZ: Are you sure that Palo Verde
10 tripped?
11 MS. WEGNER: Palo Verde units 1 and 3 tripped.
12 MR. CALLAN: Let me clarify that. There's a
13 distinction here that's important. Palo Verde can withstand
14 a loss of load without a reactor trip and, in fact, I was
15 regional administrator at the time. My recollection is that
16 the unit withstood the loss of load transient turbine trip
17 without a reactor trip.
18 MS. WEGNER: The reactors trip on a low TNBR.
19 COMMISSIONER DIAZ: But only one was actually --
20 information was only 2 and 3 you're talking about.
21 MS. WEGNER: Units 1 and 3 tripped from 100
22 percent power.
23 COMMISSIONER McGAFFIGAN: 2 didn't?
24 MS. WEGNER: 2 did not. It's because of -- I
25 presume, and it looks like it's because of the direction of

1 power flow out of the plant.

2 COMMISSIONER DIAZ: But unit 1 was not on line.

3 Unit 1 was --

4 MS. WEGNER: Unit 1 was in 100 percent power, and

5 unit 3. Unit 1, I believe, just came out of an outage.

6 COMMISSIONER DIAZ: Mr. Callan, would you like to

7 figure that out, please?

8 MR. CALLAN: I don't recall exactly the units that

9 were up or and down, Commissioner, but we'll get back to you

10 on that. I've forgotten.

11 CHAIRMAN JACKSON: There's an AEOD recommendation?

12 DR. ROSS: Let's go to slide 13. We had a single

13 recommendation from the study. NRR, which is our usual

14 receiving office -- well, sometimes it's NMSS, but we

15 requested -- NRR should request licensees to confirm that

16 they continue to meet their licensing bases with respect to

17 stability and reliability, and further, have a process for

18 ensuring they meet this licensing basis on stability for the

19 rest of their license.

20 CHAIRMAN JACKSON: That's a natural segue into

21 NRR's part of the presentation.

22 Mr. Callan.

23 DR. ROSS: Now I believe it's Mr. Jenkins.

24 COMMISSIONER DIAZ: I think I'm actually very

25 proud of it. I guess the SONGS unit, SONGS 2 and 3 did stay

1 on line.

2 MS. WEGNER: They did stay on line, yes.

3 CHAIRMAN JACKSON: We have Mr. Ray here.

4 MR. JENKINS: Good afternoon, I would like to

5 briefly discuss first the licensing basis for reliable power

6 to safety systems and components, and then those NRR actions

7 which we believe are appropriate in light of the ongoing

8 changes in the electric power industry.

9 Slide 14, please. General design criteria 17

10 details the electric power requirements for nuclear power

11 plants. The on-site and the off-site power supplies

12 together assure reliable power for safety-related functions.

13 Each power type, independent of each other, have

14 different characteristics. The on-site power source must

15 meet the scene-of-failure criteria. As a minimum, the off-

16 site power source consists of two independent circuits.

17 Each must be capable of safely shutting down the reactor.

18 In addition, GDC-17 also states that provisions

19 must be included to minimize the loss of off-site power.

20 As part of the staff's review of the licensee's

21 design, grid stability analysis which were performed by the

22 licensee must verify that the local grid remains stable in

23 the event that the nuclear unit generator is lost or the

24 largest other generating unit is lost, or the loss of the

25 most critical transmission line occurs.

1 With that short overview of the licensing
2 perspective from off-site power, the next slide describes
3 our ongoing or near-term actions.
4 CHAIRMAN JACKSON: Let me just ask you two
5 questions. The Virgil Summer event of 1989, tell me where
6 that stood with respect to any of these three factors.
7 MR. JENKINS: The Virgil Summer event reflected
8 the fact that they had not updated their grid analysis and
9 taken the appropriate action with respect to ensuring that
10 the loss of that particular unit would create a local grid
11 disturbance.
12 So technically they were not consistent with that,
13 but the problem is that that's not a hard requirement. At
14 the time plants are licensed, the staff looked at the grid
15 analysis and basically verified that, in fact, that had been
16 done.
17 But over the course of time, and this showed up in
18 the ANO event, or the licensee event, the disconnect between
19 the transmission departments and the nuclear generating
20 units sort of led to a disconnect between them. But the ANO
21 event which was led by the fact that they were going to have
22 an ESFI inspection forced them to look at their grid
23 analysis, and then of course they reported it.
24 CHAIRMAN JACKSON: So have all of our licensees
25 systematically verified?

1 MR. JENKINS: I could not state that. The -- at
2 one time, if it's stated in their SCR that they performed a
3 grid analysis, they did do that, but over time, conditions
4 change. There's no requirement at this point.
5 MR. THADANI: Let me comment. When we issue
6 information notices, we're not explicitly calling for
7 licensees to do specific analyses that they need to report
8 back to us, but there is an expectation that they need to go
9 back. Given the information in that notice, they need to
10 assess the information and its applicability to the
11 requirements that they need to meet.
12 So there is that expectation. When we find
13 information in one plant that could potentially be
14 applicable to other plants, we issue the information notice
15 that those plants will in fact look at the information
16 notice, make a conscious decision whether there is
17 information there that may be applicable to their plant and
18 their requirements that they need to go back and verify it.
19 DR. ROSS: Chairman Jackson, a typical FSAR
20 statement will be the stability of off-site power systems is
21 in compliance with the branch technical position. That's an
22 NRC branch, concerning stability, and that they have --
23 steady state and transient studies show that the loss of
24 both units, which happens to be south Texas, or the loss of
25 one unit with the other unit either on line or off line

1 would not impair the ability of the system to supply power
2 to the ESM electrical system.
3 Then it goes on and talks about stability. That's
4 a typical SFAR commitment.
5 CHAIRMAN JACKSON: So given that, there's no
6 specific requirement that if some event like this western
7 interconnect situation occurs, that they have to go back and
8 assess what's in their FSAR against what has occurred? Is
9 that what you're telling me?
10 MR. JENKINS: They would have to look as part of
11 -- being a member of the reliability council --
12 CHAIRMAN JACKSON: No. I'm talking about in terms
13 of us.
14 MR. JENKINS: From our perspective, there's no
15 requirement that they would have to do any grid analysis.
16 DR. ROSS: I do note that the --
17 CHAIRMAN JACKSON: What is -- go ahead.
18 DR. ROSS: The FSAR is written in the present
19 tense.
20 CHAIRMAN JACKSON: So you're saying that to say
21 what, Mr. Ross?
22 DR. ROSS: To me, that means whatever is true then
23 is true now. It didn't say at a certain point in time, I
24 could do this. It says it is.
25 MR. JENKINS: Certainly it would be actionable on

1 our part if we determined that there was deficiencies. They
2 would have to go and correct those deficiencies, either the
3 FSAR, or they would have to correct the plant in response to
4 the grid.
5 CHAIRMAN JACKSON: Commissioner Diaz.
6 COMMISSIONER DIAZ: I'm trying to understand the
7 role of the house power or the -- you know, our -- the
8 reactor and, you know, the power plant running.
9 If I remember correctly, when TMI happened, we
10 actually required that whole power plants will trip -- I
11 mean all the reactors will trip when the turbine trips,
12 that's correct, and then at the same time, those power
13 plants that had an integrated control system and had
14 actually bought a power run-back were authorized to
15 disconnect the power run-back.
16 And how many plants are affected like that? How
17 many plants actually had a power run-back option that would
18 allow them to trip and then restart and pick up 10 percent
19 of the load? Do we have an idea?
20 DR. ROSS: Let me comment a little bit on that
21 because at that time, the BMW plant had a -- well, of course
22 it still does -- had a pilot-operated relief valve, and on a
23 typical load separation where the primary pressure is going
24 up, the PORV would be electrically commanded to open first,
25 and then if the pressure kept on going higher, the reactor's

1 trip signal would be generated. This was built in so that
2 the ICS could run by power before they tripped on high
3 pressure.
4 One of the more immediate things that happened
5 after TMI was an emergency bulletin that reversed these set
6 points such that you got the trip first, and then the PRV
7 was challenged next.
8 That really more or less invalidated the run-back
9 feature of BMW.
10 COMMISSIONER DIAZ: It also affected the
11 Westinghouse plants that don't have the problem with the
12 power grid relief valve, will have an integrated control
13 system; is that correct?
14 DR. ROSS: I'm not sure about that, but the
15 feature did come into mind on one of the European plants
16 that had a precursor PRV stuck open years before, so I think
17 that was true, that the valve opened first and stuck open.
18 The whole idea of reversing it was to quit
19 challenging the PORV.
20 MR. THADANI: That was also the pressure trips at
21 a point were modified for reactor trip versus opening of the
22 PORV. That was all.
23 COMMISSIONER DIAZ: I was trying to determine
24 whether the power plant -- you know, the turbine trips,
25 there's an overload, the actual trips, and then we get into

1 a situation in an hour or two, you know, how we access the
2 capability of the nuclear power plants to come up and pick
3 up the house load itself and I've seen that missing from the
4 analysis.
5 MR. JENKINS: As I understand it, there's no
6 provision for picking up house loads once the plant trips.
7 CHAIRMAN JACKSON: I want to go back and try to
8 close the loop here between what your statement -- your
9 statement about FSARs being written in the present tense and
10 your statement that there's no specific requirement in the
11 -- if there is some major grid disturbance relative to
12 what's in the license -- related to the licensee, is to go
13 back and assess their grid stability analyses relative to
14 these factors that are laid out here.
15 And I don't understand. I mean, what are you
16 trying to tell us, they do or they don't -- that they are or
17 they are not required to update their analysis?
18 MR. JENKINS: I think we're saying the same thing,
19 which is that apparently a licensee has an FSAR and that
20 indicates that it includes not only a licensing basis but
21 the design basis, and if they find a condition which --
22 that's no longer true, then they're going to either have to
23 adjust one or the other, and --
24 CHAIRMAN JACKSON: Right. But I guess I'm trying
25 to get at this issue of, they find that something is no

1 longer true. The issue is, what triggers that judgment?

2 MR. JENKINS: Discovery either by the staff or the

3 licensee.

4 CHAIRMAN JACKSON: Okay. So then if something

5 happens like the WSCC events, okay, and/or the Virgil Summer

6 event of '89 and/or the ANO event, is that a discovery that

7 triggers a need for reanalysis?

8 MR. JENKINS: The western grid disturbance, given

9 its regional nature, will not necessarily force licensees to

10 look at their particular control area and say that we need

11 to reanalyze.

12 In other words, the central problem, as Mary

13 discussed with the western grid disturbance, was the fact

14 that some parties were not meeting their minimum operability

15 reliability criteria which was established by the council,

16 and the corrective actions would have to work through that

17 voluntary organization.

18 If the WSCC found that there was a problem with

19 that -- with a particular control area and it centered on

20 that plant, then that would be something that the licensee

21 or the utility would have to address.

22 But none of the conclusions I saw were that

23 specific.

24 DR. ROSS: Chairman Jackson, what I meant by the

25 present tense is that when NRR proceeds, like they said, on

1 their third bullet to implement this recommendation, they
2 certainly, when they communicate, this say this is not a new
3 requirement; remember, your plant was licensed that way.
4 So it's not like we're reinventing something. It
5 just we're saying, are you still doing what you said you
6 would do 15 or 20 years ago?
7 COMMISSIONER ROGERS: Well, I'm troubled by the
8 whole way this thing is being discussed because it seems to
9 me that our responsibilities and our licensees'
10 responsibilities are between the two of us, and now we're
11 talking about a grid that's out there, and it seems to me
12 that what we have a responsibility for is to see that the
13 licensee can function safely in the event that something
14 happens on the grid but we can't control that grid.
15 And so we're talking about -- you know, we keep
16 talking about grid stability considerations as if we can
17 control the grid through some licensing action of our own,
18 and to me that -- you know, that's never-never land. We
19 don't do that.
20 And so there's an analysis that says -- I mean the
21 statement here, the analysis must verify that the grid
22 remains stable in the event of these sorts of things, that's
23 a presumption that the licensee makes in developing their
24 coping requirements, I'll call them, and how they handle
25 those sorts of things.

1 But that's not a requirement on the grid because
2 the grid's out there and it's whatever it is. And so, you
3 know, I think that the issue which we've been ducking here,
4 I think, is that things are changing or could change out in
5 that grid that are different from the way the historical
6 record will show. That's what we're concerned about.
7 And what are the implications of that with respect
8 to our requirements on our licensees?
9 CHAIRMAN JACKSON: Exactly. That's all I'm trying
10 to get you to say. Thank you. Thank you.
11 COMMISSIONER ROGERS: We can talk until the cows
12 come home about what the reliability councils have to do.
13 We don't control the reliability councils.
14 MR. JENKINS: If we can go to slide 15, please.
15 Okay, and slide 15, this is a part of the ongoing actions,
16 future actions that we plan to take in light of these
17 changes in the industry.
18 First, we plan to monitor industry developments.
19 We met with utilities, Commonwealth Edison, government
20 authorities, such as FERC and DOE, and also with the North
21 American Electric Reliability Council. I would say that
22 this particular matter is a new area for the staff to enter
23 into before we consider the grid reliable.
24 We still consider the grid reliable and stable
25 based on the evidence that we have, however, we are trying

1 to look ahead and identify if there are any problems
2 approaching on the horizon.
3 The next bullet, we're proceeding in securing a
4 contractor to assess the risk significance due to potential
5 grid instability as a result of deregulation, and this will
6 address some of the points that you are mentioning.
7 We can't control the -- what's happening in Iowa
8 as how it affects a plant at Palo Verde, but we can assess
9 whether or not changes in the industry require us to take
10 additional actions to compensate for any grid instability.
11 As recommended by the AEOD report, we plan to
12 issue a generic communication to licensees to reemphasize to
13 them the need to maintain their design basis with respect to
14 off-site power requirements.
15 There is no change here. The equipment has to
16 have adequate voltage and frequency in order to operate, and
17 the preferred source is the off-site power system.
18 Lastly, as part of the PRA implementation plan, we
19 plan to reassess the risk from the SBO perspective.
20 Overall, we are taking a look at this brand-new world as it
21 develops, and I think in the past, the line for us was the
22 capacity to switch. Some of the grid stability
23 considerations on the previous slide dealt with when a plant
24 was initially licensed and we were concerned with the local
25 grid operation. But that was all assuming that the grid was

1 reliable and stable.

2 COMMISSIONER ROGERS: It's out there. Whatever it

3 was was not going to change.

4 MR. JENKINS: Right.

5 COMMISSIONER ROGERS: And that in the event of any

6 of these three things on -- these challenges on slide 14,

7 that the plant could handle that.

8 MR. JENKINS: Right.

9 COMMISSIONER ROGERS: See, we're using the term

10 stability and reliability. We're coupling the two together,

11 and I wonder whether there's a distinction between them or

12 if there is no distinction between them, then we ought to

13 use one term, not two. But I suggest that there might be a

14 distinction between them in that it seems to me that when

15 we're talking about stability, we really are talking about

16 certain deterministic considerations, and when we're talking

17 about reliability, we may be talking about more

18 probabilistic considerations out in the grid someplace,

19 whereas the stability analyses tend to be related to very

20 specific types of events which could then be handled through

21 a deterministic fix of some sort.

22 So I don't know what your thinking on this is, but

23 I would suggest that in the interest of clarity, either we

24 use one term, reliability, and not two, unless we really do

25 want to draw a distinction between stability and reliability

1 and how they affect licensees and how we think about the
2 grid, in which case we have to be, I think, clearer than we
3 are right now.
4 CHAIRMAN JACKSON: Dr. Thadani, you want to
5 comment?
6 MR. THADANI: I just want to say, I completely
7 agree with your comments and we do want to draw a
8 distinction and just as you described it. So we'll make a
9 point of making --
10 CHAIRMAN JACKSON: So there are two terms.
11 MR. THADANI: Two issues, yes, and we'll make sure
12 that we characterize them properly.
13 COMMISSIONER DIAZ: I just wanted to make sure
14 that when Mr. Jenkins was talking about the brand-new world,
15 are you talking about daylight time or nighttime?
16 MR. JENKINS: We have to find out exactly which it
17 will turn out to be.
18 COMMISSIONER ROGERS: Which time zone?
19 CHAIRMAN JACKSON: Well, I guess my only question
20 has to do with the following: why is it going to take until
21 the end of 1998 to do these things? And if we're going to
22 utilize contractor expertise, have we placed a contract?
23 MR. JENKINS: We're in the process of placing a
24 contract.
25 MR. THADANI: Mr. Jenkins, he was down at Oak

1 Ridge about two weeks ago.

2 MR. JENKINS: We wanted to assess the capabilities

3 of the contractor, and that was part of the delay in order

4 to have a good fit between our -- what we're interested in

5 what they can provide.

6 CHAIRMAN JACKSON: Well --

7 MR. THADANI: If I may.

8 CHAIRMAN JACKSON: Please.

9 MR. THADANI: There are a number of issues that

10 we're trying to make sure we take into consideration. I

11 mentioned reactor coolant pump seal issue. Some of the

12 inspections have identified concerns about the so-called

13 alternate AC power source at some plants, Millstone in

14 particular, there were the problems there; questions about

15 availability of the alternate AC source if there is delayed

16 loss of on-site power.

17 That is, if you don't have simultaneous loss of

18 off-site and on-site AC power, it could be, the way the

19 station blackout rule is written, it could be that an hour

20 later, and that's what happened at Millstone, an hour later,

21 because the battery charger has gone from the alternate AC

22 power source, but that alternate AC power source may not be

23 available.

24 There are a number of issues. We're trying to

25 make sure. The whole idea of trying to go to Oak Ridge and

1 trying to get additional information on this issue, the
2 potential impacts in terms of grid reliability, it would be
3 very difficult for us to move an issue at a time,
4 particularly if we're in the realm of backfits. We need to
5 be able to integrate, understand what the risk significance
6 is, and be able to support whatever actions we want to take.
7 CHAIRMAN JACKSON: Of course we have to support
8 whatever actions we want to take. Of course we have to
9 worry about backfit. Of course we have to do the cost-
10 benefit analysis. Nonetheless, the train is leaving the
11 station.
12 And the issue, to me, they're twofold, there are
13 two pieces. One has to do with, as Commissioner Rogers
14 says, all we can control is what we can control.
15 Nonetheless, we're a public health and safety agency. If we
16 know that there's a larger issue out there, even if it's in
17 the realm that we don't control, but the industry is
18 organizing itself, and it's not that they're not thinking
19 about it themselves, relative to certain kinds of
20 requirements, whether some agency needs to have some ability
21 to enforce certain things, et cetera, we might be asked to
22 speak to it.
23 We need to be in a position to speak to it in a
24 time frame that is timely relative to what's going on. And
25 that's why I'm asking the question about why is it taking us

1 two years to get to this when there could be legislation or
2 there could be actions that go on this year that relate to
3 these kinds of things. So that's number one.
4 And number two, again, we're here, you know, going
5 around the barn more generally on issues having to do with
6 licensees maintaining their current licensing bases, and we
7 have things in the FSAR that relate to assumptions or
8 analyses about, you know, grid stability and, you know, in
9 terms of coping capabilities in plants, and the Commission
10 is being asked and in the process of making decisions, you
11 know, with respect to that, and the issue again of being
12 able to inform that process in a way that makes sense.
13 And so again, we can't just kind of lull along
14 because we say, well, you know, that's DOE's Office of
15 Emergency Management, we've got to get this contracting,
16 we're going to take two years to do our thing, when the
17 train's leaving the station.
18 And that's all I'm really trying to say. We don't
19 do what we don't have the regulatory authority to do. And
20 we don't want to overstep the bounds, but at the same time,
21 if there's an issue, we need to clearly identify it,
22 identify it in a timely way, and even if it's not in our
23 regulatory purview, if there's a public health and safety
24 issue, we have to be prepared to speak to it.
25 And that's what -- I mean, I think you have to

1 develop a little bit more of a sense of urgency with respect
2 to this.
3 Is that the end of your presentation?
4 MR. THADANI: Yes.
5 CHAIRMAN JACKSON: All right, we'll hear from the
6 next panel. Thank you.
7 Well, gentlemen, I want to thank you for coming
8 and I think -- I'm assuming that -- who's the lead of the
9 discussion here? The gentleman from DOE, Mr. Meyer.
10 Okay, so why don't you give us the organization of
11 your discussion.
12 MR. MEYER: Good afternoon, and thank you for the
13 opportunity to present the Department of Energy's views on
14 matters related to the reliability of the Nation's fault
15 electric system.
16 I am David H. Meyer, electricity team leader in
17 the Office of Policy and International Affairs at the
18 department.
19 The department strongly supports the restructuring
20 that is now occurring in the electric industry because we
21 believe that it can lead to reduced electric costs and
22 enable consumers to choose among a wider range of energy
23 products and services.
24 However, the transition to competition will
25 require changes in the institutional infrastructure that has

1 been developed over the past several decades for maintaining
2 grid reliability.
3 We believe that competition and reliability can be
4 compatible, but we also believe that that result will not be
5 achieved automatically.
6 Ensuring continued reliability must be set as a
7 design requirement and taken into account as a critically
8 important policy objective by the legislators, regulators,
9 industry executives, and others who are presently concerned
10 with the overall architecture of the new electric industry.
11 I'm pleased to say that in my personal opinion,
12 this concern has been generally accepted as a critical
13 design requirement and that in one fashion or another,
14 strong mechanisms for preserving reliability will be built
15 into the new industry.
16 That, however, I have to add immediately that
17 there may be some bumps in the road before we get the design
18 set exactly right.
19 Let me turn to the department's current activities
20 related to reliability, and there are several activities
21 that come under this heading.
22 The first, and perhaps the most important to you
23 in today's context, is reliability as it relates to the
24 proposed federal legislation, that is, not DOE's own ideas
25 or views on the legislation, but more generally by others.

1 The department believes that the existing legal framework
2 for the industry is out of date and needs to be modified to
3 be relevant to a competitive industry.
4 Legislation is needed that will resolve
5 jurisdictional ambiguities, eliminate obstacles in federal
6 law to competition, and provide policy guidance and
7 direction on a wide range of issues raised by the prospect
8 of competition.
9 We have developed some concepts and draft
10 materials for such legislation as a basis for interagency
11 discussions, and we hope that these discussions will lead in
12 due course to a legislative proposal that the President will
13 recommend to the Congress.
14 CHAIRMAN JACKSON: Now, do you have this working
15 on a particular track where you developed a specific
16 interagency process and have it tracked to a recommendation
17 or set of recommendations to the President by a proposed
18 date?
19 MR. MEYER: Our proposal is in a -- has gone into
20 an interagency review process. That's not a process that we
21 can control, so we are not able to give you any particular
22 date.
23 CHAIRMAN JACKSON: And the NRC is part of that?
24 MR. MEYER: I am not sure who is and who is not in
25 on that process.

1 CHAIRMAN JACKSON: Is the NRC part of that? Can
2 anybody speak to that?
3 MS. CYR: People on my staff have been meeting
4 with a group of people at least from DOE on issues on
5 restructuring legislation. I don't know if it's a different
6 set than this, but --
7 CHAIRMAN JACKSON: You do suggest that there's an
8 actual document that's undergoing interagency review?
9 MR. MEYER: The interagency review process was put
10 on hold pending Secretary Pena's confirmation.
11 Now, Betsy Moler has been nominated as deputy and
12 my personal expectation is that she will want to take a very
13 active role in that process, so it may be that that process
14 will be delayed yet further to allow her to be in place and
15 then take an active role.
16 CHAIRMAN JACKSON: So let me make sure I
17 understand. There is or is not a draft document that's
18 undergoing interagency review?
19 MR. MEYER: There's a draft document that awaits
20 an active interagency process.
21 Reliability is one area that we think needs to be
22 addressed in this legislative debate. The existing
23 infrastructure for maintaining reliability has been
24 developed on an as-needed basis by the industry and has
25 little or no explicit basis in federal law.

1 Legislation may be needed to express an explicit
2 federal interest in reliability and provide support to the
3 industry concerning the setting of reliability standards,
4 operation of the bulk electric systems, monitoring of
5 compliance with the standards, and enforcement of the
6 standards when necessary.
7 I will return to this subject in more detail in
8 another section below.
9 Let me speak very briefly to the task force on
10 electric system reliability that the Secretary of Energy,
11 Hazel O'Leary established last year.
12 This is a subcommittee of the Secretary of
13 Energy's Advisory Board and the task force is chartered to
14 address technical, institutional, and policy issues
15 pertaining to reliability. It is chaired by former
16 Congressman Phillip Sharp, now of Harvard.
17 We were pleased that a member of the Commission's
18 staff attended the task force's March meeting, and I suggest
19 that the Commission consider writing to Mr. Sharp to express
20 its principal concerns in the reliability area so that he
21 and the other members of the task force can take your views
22 into account as they do their work.
23 CHAIRMAN JACKSON: Now, we may indeed do that, but
24 I also would ask that you make -- take the NRC's concern on
25 this issue to the task force.

1 MR. MEYER: Yes, yes. We would welcome more
2 frequent dialogue with you and others as appropriate here to
3 -- so that we have a very clear appreciation for your
4 concerns.
5 We have federal reporting requirements for major
6 system incidents. That is, that the department, in order to
7 meet its national security requirements and responsibilities
8 contained in the federal response plan, has established
9 mandatory reporting requirements for electric power system
10 incidents or possible incidents.
11 These incidents are to be reported to the
12 department through its Emergency Operations Center and the
13 type of incidents to be reported on include load shedding
14 actions or loss of firm loads, system voltage reductions,
15 public appeals for short-term reductions in electricity
16 usage, acts of actual or suspected physical sabotage or
17 terrorism, add fuel supply emergencies.
18 CHAIRMAN JACKSON: Have you been actually trending
19 this data? How recently has this reporting started?
20 MR. MEYER: That reporting requirement has been in
21 place for quite some time. We are in the process of
22 preparing a new summary which we will distribute to all
23 transmission owning and operating entities.
24 The plan is that that would be distributed under a
25 cover letter signed by the Secretary and we wish to -- the

1 thought is that this would demonstrate the Secretary's keen
2 interest in reliability issues.
3 Once an incident is reported to the department,
4 the department then alerts other agencies as appropriate and
5 works with them to develop a coordinated response to the
6 problem, if a response is needed.
7 Let me speak briefly about our participation in
8 disturbance reviews. That is, when significant outages or
9 other disturbances occur, the industry examines the data
10 pertaining to the disturbance in minute detail in order to
11 learn as much as possible from the incident about its causes
12 and how similar incidents might be prevented.
13 Last summer, as one of the 24 recommendations in
14 our report to the President on the western outage of July
15 2nd and 3rd, the department determined that henceforth, it
16 would participate in the reviews of all major system
17 disturbances, and our reasons for participating in these
18 reviews are to demonstrate our continuing commitment to
19 maintaining reliability and to learn, along with the
20 industry, all that we can about the causes and
21 preventability of such incidents.
22 Finally, let me speak briefly about our activities
23 related to systems under -- or regions under stress.
24 From time to time it becomes apparent that the
25 bulk electric system in one or another region is under

1 stress, even if no actual disturbance or incident has
2 occurred, due to severe weather, outage of one of major
3 generation or transmission facilities, or some combination
4 of such factors.
5 In these cases, an electricity staff group at the
6 department monitors the state of affairs in the region
7 closely and provides at least weekly status reports to the
8 secretary and other senior department officials.
9 In some cases, we have been able to send technical
10 staff to the affected region before incidents occur. These
11 people have worked with their counterparts from industry and
12 State and local governments to identify and execute
13 preventive -- or preventive or mitigating actions.
14 Let me turn to involvement of industry, State, and
15 federal regulatory agencies in these activities.
16 We endeavor to maintain an active dialogue, as
17 appropriate, with other parties, and we would be pleased to
18 work more closely with the Commission on matters of common
19 interest.
20 One of your questions in the letter of invitation
21 concerned activity on our part with respect to nuclear
22 safety issues in the context of reliability, and so far as I
23 am aware, the department has not as yet found occasion to
24 give explicit attention to nuclear safety issues in relation
25 to its reliability activities, but we would be happy to work

1 with you to find a way to focus those.

2 CHAIRMAN JACKSON: Well, a beginning would be if

3 we are clearly in the interagency process.

4 MR. MEYER: I appreciate that. If you want to

5 play a role, I cannot believe that there wouldn't be an

6 opportunity to do that.

7 Let me turn to our interest in the independent

8 system operator concept.

9 The department has a keen interest in the ISO

10 concept in general, although we do not wish to be understood

11 as endorsing any particular one of the many ISO designs and

12 proposals now in circulation.

13 The ISO concept became popular as it became

14 apparent that in the competitive wholesale market, it will

15 be necessary to ensure that regional transmission networks

16 are run without discrimination against any participants in

17 the market's commercial transactions, and that utilities

18 that own both generation and transmission could avoid

19 conflict of interest problems by acceding the operation, if

20 not the ownership of their transmission facilities to an

21 independent party.

22 But secondly, it also has become apparent that

23 there is a need to ensure that the regional transmission

24 networks would be run without stressing them beyond their

25 physical limitations, but also without allowing those

1 limitations to be used as a pretext for discrimination to
2 the advantage of some market participants and the
3 disadvantage of others.
4 Both of these concerns imply that there will be a
5 strong and enduring need for independent regional scale
6 transmission entities. As federal legislation to update the
7 legal framework for the industry takes shape over the coming
8 months, consideration should be given to provisions
9 pertaining to ISOs.
10 Like reliability itself, ISOs appear to be too
11 important, too critical to the successful function of the
12 new industry not to warrant explicit coverage in the new
13 legal framework.
14 Let me conclude then by going back to the subject
15 of reliability provisions in proposed federal legislation.
16 The department has not yet offered its proposal, but -- and
17 so here I can only mention ways that reliability might be
18 addressed in federal legislation.
19 One approach would be to authorize a federal
20 agency, such as the FERC, to approve reliability standards
21 developed by affected parties through a membership-based
22 organization.
23 The agency that is -- possibly the FERC could also
24 be empowered to approve procedures proposed by a reliability
25 organization for the organization's own activities,

1 including monitoring and enforcement of the standards.

2 Finally, the legislation can provide the agency

3 with the authority to enforce the standards itself if

4 necessary, although the initial responsibility for

5 enforcement might reside with an industry organization.

6 That concludes my statement and I would be happy

7 to answer questions at your convenience.

8 CHAIRMAN JACKSON: Okay, I think we'll go through

9 -- I think what we'll do is start with you, Mr. Gent. Is

10 that the correct pronunciation of your name?

11 MR. GENT: Yes, it is.

12 CHAIRMAN JACKSON: And then we'll go through the

13 different regional, and we'll let you Mr. Nye, last but

14 certainly not least, tell us the real deal from the

15 industry.

16 MR. GENT: Thank you, Madam Chairman. Good

17 afternoon, commissioners. I'd like to thank the Commission

18 for extending this opportunity to the North American

19 Electric Reliability Council for us to talk about what we're

20 doing in the way of reliability and how deregulation might

21 affect reliability.

22 I'd like to start by saying something that's not

23 in my prepared remarks. I've noticed while sitting in the

24 audience that you have this desire to participate in this

25 process and I'd like to offer that invitation for the NRC to

1 participate in any, all, some, or none of our processes at
2 any time you would like immediately without going through
3 NERC processes, peer review.
4 We would welcome your attention. Your staff has
5 visited our offices and I'd like to invite them back because
6 I think a lot has happened since they were there when they
7 were preparing this report that served as a basis for this
8 discussion.
9 As you know, NERC's responsibility is the high-
10 voltage grid that interconnects generators and load centers.
11 We have three major grids in the United States and Canada.
12 Some say four. It depends on how you count Quebec. That
13 would be the fourth.
14 We call them in our terminology interconnections
15 and I understand what Commissioner Rogers is saying about
16 the terminology. We have some very strict terminology that
17 probably conflicts with your very strict terminology in many
18 cases.
19 So as we have defined reliability, we break it
20 into two parts. We talk about adequacy and we talk about
21 security, and I've learned that security means something to
22 everybody a little bit differently than it means to us.
23 In this case, it means that we must be able to
24 withstand a large contingency outage. Your staff has listed
25 a number of examples in their report, transmission lines,

1 corridors, generating plants and the like.

2 Our initiatives dealing with security and

3 standards relate directly to your interests in grid

4 reliability. We require that there has to be enough

5 spinning reserve to be able to withstand those

6 contingencies. We need to ensure that these units that have

7 the spinning reserve are strategically located and we have

8 to ensure things like transmission lines have enough room

9 left to withstand these losses.

10 The public in general doesn't understand why we

11 can't load transmission lines right up to the maximum

12 thermal rating, and I think after listening to this, I'm

13 sure you understand that there is a stability issue. There

14 is also a contingency issue.

15 To help us reliably handle the increasing number

16 of transactions, NERC is establishing a network of 22

17 security coordinators graphically and electricity

18 distributed across North American. And many of the other

19 speakers that follow me will be addressing those security

20 coordinators.

21 This is the real key to instantly providing a

22 reliable network. These coordinators are going to have

23 their own dedicated communications network, we call it

24 interregional security network, or ISN and it will begin

25 operation as soon as June of this year with some limited

1 functionality.

2 Today, our security coordinators are implementing
3 several interim procedures and processes so that the more
4 sophisticated tools that they'll need to make definitive
5 judgments, and, yes, even run stability studies, are fully
6 developed. The ISN is going to ramp up to full
7 functionality later in 1997 and we hope will be totally on
8 line in the early part of 1998.

9 These 22 security centers will be responsible for
10 conducting security analysis of the grid with on-line data,
11 and will have the authority to take the actions necessary to
12 prevent or relieve overloads or prevent potential risk to
13 the grid.

14 This very elaborate system should allow many
15 multiples of additional transactions to take place in this
16 new deregulated open access world that we are surely facing.

17 You've asked in the notes that I received earlier
18 about how the governance that would involve an independent
19 system operator concept --

20 CHAIRMAN JACKSON: Before you go on, let me just
21 ask you this question. Do nuclear plants receive any
22 special recognition in protecting their off-site power,
23 their access to off-site power?

24 MR. GENT: Yes, they surely do.

25 CHAIRMAN JACKSON: Could you tell us how that

1 works?

2 MR. GENT: Yes. In an operational sense, if you
3 look at what I have attached to my material, you'll see that
4 I have excerpted what's called a NERC operating manual.
5 This is just a cover sheet.

6 If you look a little bit deeper at the table of
7 contents, you'll see something I've highlighted in yellow.
8 It's called operating policies. And then I've gone a little
9 bit deeper. Policy number 5 on the next page, for instance,
10 refers to emergency operations, and then the number E item
11 there is called system restoration.

12 I realize this is a lot of detail, but if you will
13 shift with me now to a page that's numbered at the bottom
14 P5-7, there will be a reference to system restoration.
15 There's something called requirements. This is something
16 that's required. These are must-do things.

17 In this case, when you're restoring the system
18 from some system collapse or an outage such as we had in the
19 Western Systems Coordinating Council on August 10th, under
20 the requirements, you see steps one through five. The fifth
21 step in this process is off-site supply for nuclear plants.

22 This is the first thing that happens after the
23 system is brought back together, resynchronized and judged
24 to be functioning. This is before we bring back any other
25 loads or generating plants. The first thing we do is try to

1 bring back the nuclear plants.

2 CHAIRMAN JACKSON: Well, as part of that, do you

3 have specific information as to the coping capabilities of

4 the nuclear units in a particular region to -- relative to

5 how long the unit or units can go without off-site power,

6 the provision of off-site power?

7 MR. GENT: I don't have information of how long

8 they could go without off-site power.

9 CHAIRMAN JACKSON: So that's not readily available

10 to those who would be in the position of working to restore

11 the provision of off-site power?

12 MR. GENT: I don't know that that's the case.

13 MR. DELGADO: That information is available in the

14 EMS screen. We have figures built into the energy

15 management system that address the needs of our plants.

16 There are written and screen procedures similar to this.

17 And of course we also monitor the plant, for example, the

18 alarm, so that the operator -- even when the plant is out,

19 the operator can do something about voltage levels that is

20 required to meet the requirements of the power plant.

21 CHAIRMAN JACKSON: I'm asking a slightly different

22 question. That is, let's assume there's been, you know,

23 some loss of the grid, and now you're working to restore the

24 power. I guess what I'm trying to understand, you know that

25 there the different stations have different coping

1 capabilities depending upon their own on-site power sources
2 and design of the plant. And the question is, is there --
3 as part of this grid management and restoration you say
4 should be given high priority, but that has to be informed
5 by what the actual status is of the given plant.
6 MR. GENT: We have actual real-time communication
7 with the plants, and if they were to have specific problems,
8 my operators and the plant operators would be in
9 coordination. We generally know of their requirements and
10 they know of the status of the grid in preparation for these
11 events, and in real time, we can tune the situation by
12 direct telephone communication with ring-down circuits.
13 CHAIRMAN JACKSON: Do you have a worked-out
14 protocol relative to the nuclear plant?
15 MR. WOLFF: I'm struggling with the word protocol
16 but we have a worked out, ongoing daily relationship of
17 talking with the plants, and if you will accept that as a
18 protocol, yes, we have a protocol. It may not be written in
19 a document somewhere. It is a general agreement to operate
20 and communicate.
21 MR. DELGADO: Maybe I can address it. From our
22 perspective, we do have the procedures which have been
23 written in conjunction with the power plant, so our plant
24 staff has -- in preparation for this meeting, I checked and
25 the last one I saw was revised in April of this year, so I'm

1 satisfied that we're keeping up with it.

2 Whether or not -- and I cannot answer your

3 question, whether or not the operator knows how long the

4 power plant can be black. By giving it top priority, I can

5 assure you that it's getting it as soon as the operator can,

6 in other words, getting first priority.

7 So -- and besides that, the communication is

8 pretty solid from the perspective of dealing directly with

9 the power plant by hands off operating and communication is

10 not required. Line communication can be done hands off.

11 So by having a top priority issue, it assures us

12 -- it assumes the system is energized with the black start

13 plants. The nuclear power plant will be given the first

14 priority in getting access to it.

15 Besides, since they are connected to a backbone

16 345, which is the highest voltage we have, in any

17 restoration of the system, you begin with the black plant

18 and you go right to the backbone. So those plants naturally

19 will receive priority because you right away want to get to

20 the backbone.

21 CHAIRMAN JACKSON: You don't have any 765 kV?

22 MR. DELGADO: Sometimes I wish we did, but right

23 now we don't, no, and I don't expect we will in the near

24 future, but 345 is quite ample for us.

25 COMMISSIONER ROGERS: Would that be true in all

1 the regional coordinating councils?

2 MR. DELGADO: I have a map here of Maine and I can

3 assure you if you look at it, the thick lines join all

4 nuclear power plants.

5 COMMISSIONER ROGERS: No. I'm talking about the

6 whole country now. I'm not talking about a regional. I'm

7 talking about now every regional, whether that's the case.

8 MR. GENT: I'm not sure this will answer your

9 question, but virtually every plant has a procedure and

10 protocol for being restored to the network and there is an

11 order in which they're called in to do that depending on the

12 situation, but everyone has a plan that includes that.

13 COMMISSIONER ROGERS: See, the question that I

14 haven't heard a direct answer to is whether there is

15 something different about how a power pool treats nuclear

16 plants from how the regional coordinating council treats

17 nuclear power plants.

18 Because you may have a -- you know, a larger

19 problem than just one that is in a particular power pool

20 grid that extends well beyond that, and then the question is

21 whether the coordinating council has a particular way of

22 dealing with nuclear power plants in the broader region.

23 That's the question I think that we haven't had an answer

24 to.

25 MR. WOLFF: I brought with me two paragraphs that

1 indicate that we do have a formal procedure for ensuring
2 that nuclear plants receive the highest priority. That is
3 in conjunction with NERC requirements and I can assure you
4 that the New England Power Pool and New York Power Pool and
5 PJM do it that way. We're known as the three tight pools.
6 I have no reason to believe it's not done that way in other
7 areas. I'm sure it is, but I know for a fact it is done in
8 the whole northeast region.
9 COMMISSIONER ROGERS: Yeah. Well, it's a question
10 -- it's a national based question rather than a regional
11 based.
12 COMMISSIONER DIAZ: Is the NRC notified when
13 something like this happens and you're actually trying to
14 restore the load? Is our incident response seen on the
15 network?
16 CHAIRMAN JACKSON: I think our information comes
17 through our licensees. Okay.
18 MR. GENT: I mentioned the NERC operating manual.
19 There are a number of other issues in there that you may be
20 interested in and I'd be happy to provide your staff with a
21 copy or as many copies as you'd like and answer as many as
22 questions as you might have.
23 Regarding the governance issue, whether governance
24 of ISOs is going to affect reliability, we think that that
25 is not going to be the case and I'd like to explain why.

1 Our initiatives are based on separating transmission
2 operations and reliability from a marketing function. We're
3 trying to do that right now.
4 If an ISO is a means to achieve this separation of
5 market and operating function, then certainly it will be
6 successful in creating the separation and independence and
7 they will enhance reliability.
8 What we're doing now with our security
9 coordinators is getting out in front of this. We think that
10 eventually they'll probably evolve into ISOs if that truly
11 is going to be what the industry will be shaped like.
12 Today, however, we need to move on, and so to make
13 sure that our security coordinators, these 22 locations
14 around the United States and Canada, are truly acting
15 independently, we've asked them all to sign data
16 confidentiality agreements.
17 This is necessary because some of the data they
18 need for reliability purposes and analysis can be used to
19 somebody else's commercial advantage, and I think you can
20 understand how they're fairly skittish at doing that.
21 So we think that the best way to handle this,
22 without it taking an awfully long time, is to have them sign
23 data confidentiality agreements. That's in the process
24 right now.
25 Our security coordinators will then be independent

1 of the marketing function and will not be affected by any
2 decision made by the governance of an ISO.
3 I've mentioned our operating standards. I need to
4 talk about our planning standards, which you may have some
5 interest in as well. These are not nearly as well-defined
6 as our operating standards. We're now approaching the issue
7 of elaborate planning standards. It's under way and I would
8 invite the Commission to participate.
9 I'm personally going to take the issues I've heard
10 here today back to the groups working with this and see that
11 there is a consideration of the stability issue, viewing
12 with me your licensees to see that that's an updated process
13 and done fairly often.
14 I think that as soon as we get into this, we'll
15 see that it is a process that's now considered. I just
16 can't testify to it.
17 I hope from the comments that you'll hear from
18 those that follow me and from me, we believe that NERC's
19 interest here is really in seeing that the grids are not
20 only reliable today, but they remain reliable through the
21 coming years during the restructuring and after.
22 We agree in large measure with the conclusions of
23 the report that was presented to you earlier, and then I
24 said earlier, I think we need to revisit not only the report
25 but have the staff revisit with NERC staff to learn what

1 changes have been made since they visited this.

2 I thank you again for this opportunity and I'm

3 sure that there will be other questions. I'll try to answer

4 them along with the others on the panel.

5 CHAIRMAN JACKSON: Well, I'd like to ask you a

6 question couples relative to the submission that you've

7 made. You were talking about your processes for developing

8 operating and planning standards have been accelerated and

9 are being changed to include more opportunity for input by

10 all affected parties.

11 And you talked about ways of enforcing standards,

12 and you said regarding that enforcement, one possibility is

13 that we will end up with what are generically called a

14 reliability -- calling a reliability compact, which will

15 probably consist of a series of contracts that specifically

16 obligate the policies to abide by the NERC standards.

17 Does this need some kind of a federal backing or

18 legislative undergirding? And when the industry

19 representatives speak, I'm going to ask them to address that

20 issue separately. But I want to hear from you.

21 MR. GENT: You'll probably get four or five

22 different answers. This is currently the issue under debate

23 now. We know what the rules are, we know what they should

24 be. How do you enforce them when somebody says I'm just not

25 going to do it?

1 We currently have a process that has worked, but
2 we're anticipating that as competition gets heavier and
3 heavier, we're going to have some people that refuse to obey
4 by the rules.
5 The best way we have right now is with contracts,
6 and to the extent the contract law works, this will work.
7 But we are debating whether we do need some federal
8 backstop. We're a little bit timid in asking for it because
9 we often get more than we ask for. And I think that was
10 evident from a previous presentation.
11 CHAIRMAN JACKSON: Also, I note that you claim
12 that with respect to the last issue we had asked you to
13 discuss in terms of factors and considerations used in
14 establishing reliability governed structures vis-a-vis loss
15 of off-site power events for nuclear power plants, that you
16 say that language is being included in some ISO agreements
17 that requires ISOs to operate the grid in accordance with
18 special operating criteria established by NRC operating
19 licenses.
20 Do you think that's a good idea in general?
21 MR. GENT: I think we absolutely must visit that
22 issue to make sure that it has been considered. I'm certain
23 it has. I just can't testify to that. But I will be able
24 to soon.
25 CHAIRMAN JACKSON: And you also were talking about

1 that NERC is the home of the generating availability
2 database, and you say you're primarily interested in, these
3 days, in the types of data that would allow us to model a
4 nuclear unit during a transient or slightly slower dynamic
5 disturbance event.
6 That kind of modeling doesn't go on today? I'm
7 going to ask the --
8 MR. GENT: Yes, it does.
9 CHAIRMAN JACKSON: -- industry people to speak to
10 this too. So if it does, what's the issue?
11 MR. GENT: The issue is one of size. Before, most
12 of this type of modeling has been done by your licensees,
13 and we've learned very recently that these outages spread
14 over entire regions, like the entire western United States,
15 and we need to extend our modeling to include more than just
16 your licensee's area, and having the rest of the world as an
17 equivalent, we need to get into huge modeling, and that's an
18 issue with planning people in NERC.
19 CHAIRMAN JACKSON: Do you have the resources and
20 capability to do that?
21 MR. GENT: We're not sure that we have the
22 resources and capability to do that. We need to find out.
23 It's never been done before.
24 CHAIRMAN JACKSON: Is this a path you're
25 definitely planning to go down?

1 MR. GENT: Yes, it is.

2 CHAIRMAN JACKSON: All right. Any questions?

3 COMMISSIONER DIAZ: I have just a piggyback on the
4 Chairman's question on that next to last paragraph where it
5 says, "language being included in some ISO agreements." Is
6 there any reason why some is selected or are we going to try
7 to -- everyone is using it?

8 MR. GENT: There's only one ISO agreement now in
9 force and that's in Texas. What's being proposed in
10 California will also honor the agreements of the licensees
11 in that ISO agreement. So that was the reason for the
12 reference to some.

13 But I think that you can expect, especially after
14 this process today, I think you can expect they will all be
15 aware that there needs to be a consideration in the
16 agreement.

17 CHAIRMAN JACKSON: Let me hear from Mr. Wolff.

18 MR. WOLFF: Thank you, Chairman Jackson. I'm
19 pleased to be here to give you some feeling for what it's
20 like to be an ISO.

21 First, by way of background, I've been in the
22 industry for about 39 years in charge of distribution, in
23 charge of station plant design for Indian Point 1 and 2 when
24 I was at Con Edison, in charge of the control room at Con
25 Edison, which is an 8,000 megawatt control area, so I know

1 what it's like to operate a control area as an individual
2 company.
3 I have had grid planning and construction
4 experience and now four years as the CEO of the New England
5 Power Pool so I know what it's like to operate a grid from a
6 power pool standpoint.
7 We are effectively an ISO and have been for some
8 25 years. The term has come to mean new things now, but we
9 have been an ISO for those people that supply the electric
10 industry during that 25 years. That group of people has
11 expanded and the term ISO now means you're dealing with not
12 only utilities, but marketers and the rest.
13 But we will do very little different in the
14 management of the New England Power Pool from what we have
15 done, and I'd like to give you a feeling for that.
16 We were formed as a result of the 1965 blackout in
17 order to ensure reliability in that area. What will change
18 as we become an official ISO? Our governance will change.
19 We like to think that we are very fortunate. We
20 are, at least at present, the only ISO in the nation that
21 will have an independent board of directors. They have been
22 selected and are about ready to be put into place. It is
23 not a sector board of various interests. It is a single
24 monolithic board dedicated to reliability, dedicated to the
25 ISO, and dedicated to supplying nuclear plants and ensuring

1 that the facilities are built into the system to make it
2 happen. They have no other vested interest than our
3 interest of reliability. So we're quite fortunate.
4 As a matter of fact, this meeting is my last
5 official duty before going into retirement. This whole
6 thing is getting ready to move and so I do cherish the
7 opportunity to talk to you just before retirement.
8 But I can say that I am quite pleased with the
9 excellent board members we have, names you might be familiar
10 with is Charles Stalen and other people with fairly
11 reputable reputations. I think that they will back the
12 interests --
13 CHAIRMAN JACKSON: Is this the Stalen who was at
14 FERC?
15 MR. WOLFF: Yes, it is. And we have people in the
16 regulatory markets and in the marketplaces in reliability
17 and in the industry. So we are positioned to move forward.
18 What else is going to change? Our method of
19 dispatch will change. We have for 25 years been dispatching
20 the system every five seconds on the basis of least cost.
21 That has been very effective. We have huge computers that
22 capture the data, make the dispatch, and monitor the entire
23 system to make sure economy is in place.
24 What else is going to change? I project that we
25 will have additional power now that we have a board. The

1 regulators in New England, an organization known as NEPURG,
2 the New England Public Utility Regulatory Group, are very
3 much behind the process. They were involved in the
4 selection of the board.
5 They have, as Mike said, actually given me a
6 little more power than I feel comfortable with at times. I
7 think a limited amount of power is good. I think too much
8 could be dangerous, but barring that possible problem
9 sometime in the future, we have been reasonably well
10 empowered to enforce the reliability rules.
11 Now, how do we address reliability? I'm very
12 interested in the questions you asked about reliability and
13 stability and that sort of thing.
14 They do mean different things and they're more or
15 less in the eye of the beholder, but reliability means how
16 much of the time are the lights going to be on? Now, they
17 can go off for different reasons. They can go off because
18 we have a slowly growing load and we've had to go to load
19 shedding in order to balance load and generation when we run
20 out of generation.
21 First we ask for voluntary appeals, and then we
22 get the involuntary appeals if things get bad enough. We
23 have not had to do that in New England. The last incident
24 that I'm particularly familiar with when it was consciously
25 done was in this area in January 19th, I believe, and it was

1 conscious rolling blackouts.

2 CHAIRMAN JACKSON: Is it well -- within a given

3 power pool, is it well understand how low the voltage and/or

4 frequency margins can show before you have a potential for

5 some instability?

6 MR. WOLFF: Yes, it's extremely well-known and we

7 do the studies, we model the system, and we actually

8 practice voltage reductions during the spring time of each

9 year in order to see that they work and give us what we want

10 and they're not excessive, so the answer to your question is

11 quite clearly, it is known.

12 CHAIRMAN JACKSON: And that is automatically

13 coordinated with the actual plants or the utilities that

14 operate the plants?

15 MR. WOLFF: Yes, it is. We coordinate directly

16 with Millstone and have a voltage schedule based on

17 Millstone's needs and they determine those needs and we

18 follow that schedule and drive the base points at the

19 substations around Millstone to make sure they do not go

20 below those voltage requirements.

21 So we, in fact, do meet your requirements very

22 specifically in coordination with the utilities, and we have

23 some voltage schedules throughout New England to make sure

24 we don't have a voltage collapse.

25 Now, getting back to the area of stability, once

1 we have ensured the reliability by balancing load and
2 generation, using both sources, load and/or generation, we
3 have to worry about the stability issue, which is the issue
4 that is taken care of by what we call security constrained
5 dispatch.
6 In other words, we will not dispatch the system to
7 a load level or to a transmission line loading level which
8 will result in a problem for the loss of any generator or
9 any major system.
10 So we are already looking in advance. The
11 computers are constantly monitoring, what happens if this
12 generator goes out, what happens if I lose a Canadian power
13 source, what happens here? They will make that study, check
14 the stability, determine if we can survive that event, and
15 if we can't survive that event, we will dispatch additional
16 generation, change the dispatch, go off economics, make a
17 contract with New York to import additional power. There
18 are many, many ways to solve the problem. This is a cat
19 that can be skinned in many different ways, and it is the
20 job of the operator to determine which way is the most
21 reliable, which is the quickest way, and which will achieve
22 the desired result.
23 So when we do a security constrained dispatch, we
24 take care of the stability issue. That's how we do that,
25 because stability is something you have to prepare for

1 before it happens.

2 The same as voltage collapse, is something you
3 have to prepare for before it happens, possibly even the day
4 before. If you're not ready for a voltage collapse, it's
5 too late to do anything about it. Once it starts to sag,
6 you're in a worse position than before it sagged.

7 So that all will remain exactly the same in the
8 New England Power Pool. We're quite fortunate. For the
9 last 25 years, the New England power utilities have allowed
10 us to operate that grid as if we owned it, and they have
11 charged us with operating it as if we own it in order that
12 they could gain the relief necessary for knowing somebody is
13 looking at the farm and making sure everything is done
14 properly.

15 We look at the whole system in a coordinated way.
16 We coordinate with the New York Power Pool, we coordinate
17 with Quebec, we coordinate with PJM. We even are limited by
18 certain flows across the central portion of Pennsylvania
19 that limit our Canadian imports, so there is the ability and
20 it is done every day in practice to coordinate across
21 regions, and it is done by the operators in real time and is
22 in no way in conflict with what Mr. Gent is suggesting, a
23 broader and greater scope of this coordination, and I
24 wholeheartedly support that additional scope as part of an
25 answer to one of your questions.

1 I mentioned the security constrained dispatch. We
2 continue to support all of the NERC criteria. We as
3 operators find it very consoling to have that criteria in a
4 time of competition. There's no question that the members,
5 the players in the market, have fiduciary responsibilities
6 to their stockholders and they will have to make tough
7 decisions, but I am sure they won't directly conflict with
8 reliability, but having a set of standardized rules and ISOs
9 who are empowered to take care of the reliability aspect is
10 very consoling.
11 If you stop to think of it, there are only three
12 people that are interested in reliability: The customer
13 most assuredly is, the regulatory bodies, and the ISOs. I
14 don't believe it is proper to charge the individual players
15 totally with reliability because they have a direct
16 conflict.
17 We are prepared to set the system up and make sure
18 that the incentives are there for all the players to bring
19 to the table the assets that we need, transmission,
20 generation, and the like.
21 In the past, we have monitored reliability by
22 looking at reserve levels and doing a statistical analysis,
23 Monte Carlo type outage analysis on generators, lines and
24 the like.
25 In the future, since we don't have direct control

1 of that, we in New England have decided to go toward other
2 incentives, such as operable capacity.
3 If you remember when Pilgrim was out for several
4 years a couple years back, that plant received capacity
5 credit and was in the planning criteria even though it had
6 been out for two years. The owning utility got capacity
7 credit because statistically it works. There were other
8 plants that were in.
9 In the world of the future, we will not be able to
10 give capacity credit for two years for a plant that is not
11 operating. So we have changed our criteria. We are
12 insisting that all the players go to operable capacity to
13 take care of reliability.
14 What I'm saying to summarize is, we can take care
15 of reliability several different ways, and in this new
16 marketplace, we will have to find those new ways to take
17 care of reliability. There are ways. If we do it right,
18 there's no reason for reliability to suffer and there's no
19 reason for anybody to have interests that conflict with DOE,
20 your Commission, or anybody else.
21 CHAIRMAN JACKSON: Do we need any kind of federal
22 legislative backing?
23 MR. WOLFF: Well, I think NERC is in a position to
24 require these things. I think the good faith and support of
25 the Federal Government is always good. A limited

1 involvement. I'm one of those people who believes that
2 limited involvement is probably good. Complete ignoring the
3 situation certainly is not good.
4 Too much involvement, my personal opinion, is not
5 necessarily good either. That's just my personal philosophy
6 on things.
7 CHAIRMAN JACKSON: But a system where some agency,
8 whether it's FERC or whatever, might lay out some baseline
9 criteria but that the NERC has the primary responsibility
10 but the ability to enforce it based in some statute is not a
11 problem?
12 MR. WOLFF: No, that's not a problem.
13 CHAIRMAN JACKSON: Okay, let me hear from Mr. Eyre
14 from Western Systems.
15 MR. EYRE: Chairman Jackson, I'm sure you're aware
16 the WSCC is the largest and most diverse of the ten regional
17 reliability councils of America. WSCC has 99 members
18 ranging from 71 traditional utilities to 10 independent
19 power producers and 18 marketers. So we have all segments
20 of the industry involved in the council's activities.
21 It also includes three regulatory representatives
22 that serve on WSCC's Board of Trustees. Let me take a
23 moment just to review with you who is responsible for
24 reliability today and where it should be in the future.
25 As the industry restructuring occurs and we

1 implement competition, it is imperative on all of us to make
2 sure that we maintain a reliable electric system.
3 For over 30 years, NERC and the regional
4 reliability councils have been the caretakers of reliability
5 through the cooperative development of NERC and regional
6 council policies, procedures, and criteria.
7 There is no reason to doubt the ability, the
8 appropriateness and the resolve of NERC and the regional
9 reliability councils to continue to serve as self-regulating
10 organizations.
11 CHAIRMAN JACKSON: Now, you're telling me this in
12 spite of the two events that happened in the summer of 1966
13 -- I mean 1996?
14 MR. EYRE: Absolutely.
15 CHAIRMAN JACKSON: And why should I have that
16 comfort?
17 MR. EYRE: Why should you have that comfort? I
18 think what you see happening as of the disturbances that
19 happened last summer is a resolve that the councils are
20 doing right now, to make sure that everything is in place,
21 everything will be administered, and as I go on through my
22 presentation, you'll see, at least in the west, we're moving
23 rapidly to implement a reliability compact that calls for
24 mandatory compliance with sanctions, incentives, financial
25 penalties as may be appropriate.

1 CHAIRMAN JACKSON: And that did not occur before?
2 That did not exist before?
3 MR. EYRE: We did not have the sanctions and
4 penalties provisions available to us prior to those
5 disturbances.
6 CHAIRMAN JACKSON: So you're saying that you've
7 gotten religion now and that's the reason --
8 MR. EYRE: That's a good way to put it. It was a
9 wake-up call to the whole industry to see what can occur if
10 in fact we do not have the mechanisms in place to make sure
11 we have compliance with the rules of the road.
12 CHAIRMAN JACKSON: Okay, go on.
13 MR. EYRE: WSCC and NERC are committed to
14 enhancing accountability for reliability and improving
15 compliance with reliability standards. WSCC strongly favors
16 an industry self-regulating organization approach with a
17 federal and/or state regulatory backstop as may be
18 appropriate.
19 Let me take a few minutes just to outline to you
20 some of the activities that are being taken in the west to
21 ensure reliability.
22 CHAIRMAN JACKSON: Let me back you up. Elaborate
23 on that sentence a little bit.
24 MR. EYRE: As far as the backstop is concerned?
25 CHAIRMAN JACKSON: Correct.

1 MR. EYRE: I think I would support the earlier
2 comments, that I think a limited involvement would be
3 appropriate. I think it is also necessary. There is one
4 thing that the industry cannot do by itself. It can design
5 programs for mandatory compliance. It can design a program
6 for sanctions, incentives, and penalties, but it has no way
7 of assuring that it can get everybody at the table and
8 that's where we need support from the regulatory community,
9 to make sure that everyone is at the table helping design
10 those mandatory criteria and making them accountable and
11 also subject to the penalties or incentives that we feel is
12 appropriate.
13 CHAIRMAN JACKSON: So would this kind of backstop
14 be some kind of federal action, say, mandating NERC
15 membership?
16 MR. EYRE: There are several ways that that could
17 be done. That is one way it could be done. It could be
18 done through licenses by the Public Utility Commissions of
19 the various states. It could be done with -- through FERC
20 mandating to the jurisdictional utilities who they do
21 business with those types of things. Those are just various
22 options.
23 WSCC is continuously and expeditiously
24 implementing new protocols and mechanisms to ensure
25 reliability is not sacrificed as we restructure the

1 industry.

2 In 1996, the WSCC Board of Trustees unanimously
3 endorsed a reliability compact that reaffirms the council's
4 mandatory compliance requirements and which will result in
5 the enforcement of established reliability protocols in the
6 west.

7 The compact recognizes that to ensure continued
8 reliability, all market participants must adhere to the
9 established reliability protocols.

10 A policy level group has been formed to develop
11 incentives and sanctions for implementing the reliability
12 compact. These recommendations will be submitted to the
13 WSCC membership by the end of 1997.

14 The WSCC agreement states that all control areas,
15 which includes the ISOs, must be members of WSCC. And as
16 such, they must comply with all WSCC and NERC protocols and
17 sanctions.

18 Also, and of importance to you as we've already
19 discussed, the most recent filing of the California ISO
20 filing includes a transmission control agreement which
21 requires the ISO to meet the WSCC and NERC protocols and the
22 provisions of NRC plant licenses.

23 In addition, system operators are required to give
24 a high priority to nuclear plant restoration, as already
25 mentioned in the NERC policy 5. I believe, however, that we

1 interconnected system reliability through the exchange of
2 information required to assess system security and
3 reliability, including on-line power flow and security
4 analysis and increased system monitoring.
5 These measures will enhance the operator's ability
6 to identify potential reliability problems and promptly take
7 proactive corrective actions to ensure system reliability.
8 The council has approved a regional security plan
9 that is intended to convey both the responsibility for
10 overall system reliability and the authority needed to carry
11 out the responsibility successfully.
12 This plan was developed and is currently being
13 implemented in response to one of the four strategic
14 initiatives for reliability established recently by NERC.
15 The regional security plan empowers the security
16 coordinators to take the actions necessary to preserve
17 reliability. The California ISO will be one of the security
18 coordinating centers, and it is envisioned that as the other
19 ISOs are formed in the west, they will also become the
20 security coordinating centers for their section of the
21 interconnected system.
22 WSCC has also established a successful training
23 program that has been carefully structured to provide system
24 dispatchers and other operating personnel with the necessary
25 skills to deal with the ever increasing complexity of

1 interconnected system operation.

2 In addition, a schedulers/contract writers

3 training program was implemented in 1996. This training

4 program familiarizes schedulers, contract writers and energy

5 accountants with system operations and increases their

6 understanding of how their actions impact interconnected

7 system operation and system reliability.

8 Although WSCC currently has an operation training

9 program, we are currently working with NERC to implement a

10 certification program.

11 Moving on, you have often heard the question or

12 maybe asked the question yourself: is the transmission

13 system being used differently than originally designed and

14 will it impact reliability? The answer to the first part of

15 the question, is it being used differently than originally

16 intended? And the answer in most cases is yes.

17 Will it impact reliability? As long as

18 established operating protocols and those implemented by the

19 industry are followed, transmission reliability should be

20 preserved. Industry and regional reliability councils

21 recognize the changing competitive nature of the industry

22 and the impact this may have on system operations.

23 As such, and as we speak, new protocols are being

24 developed to address changes occurring and being forecast

25 for electric system operation in the future.

1 As we restructure --

2 CHAIRMAN JACKSON: Let me ask you a question.

3 These new protocols that are being developed as we speak,

4 how are they going to be verified to be adequate?

5 MR. EYRE: Well, number one, in our compliance

6 program, they will be part of our protocols criteria that

7 must be followed. As part of our compliance program, we

8 will be monitoring those to be sure they're complied with,

9 number one, and through that compliance process and review

10 process, we will identify the needed changes that will be

11 needed.

12 As we restructure the industry, there are a few

13 implementation issues to consider. We must make certain

14 that interconnected system reliability is preserved. As

15 time frames are established for restructuring the industry,

16 we must all bear in mind that these time frames must be

17 realistic and prudent, and that they may have to be revised

18 to maintain reliability.

19 The regulatory community, especially the Federal

20 Energy Regulatory Commission and the state regulatory

21 agencies will need to serve in a backstop role, providing

22 NERC and the reliability councils with the required tools to

23 maintain and ensure reliability. The regulatory community

24 should then hold NERC and the reliability councils

25 accountable for ensuring reliability.

1 We must ensure that all entities that own, operate
2 or use the interconnected transmission system are complying
3 with the established criteria, guidelines, and policies. To
4 ensure compliance, NERC and the reliability councils must be
5 able to monitor those involved and correct those in non-
6 compliance.
7 Where financial or business incentives cannot be
8 developed to ensure compliance and accountability, the
9 regional reliability councils and NERC, working with the
10 ISOs and others, must have the ability to impose sanctions
11 or fines on non-complying members, so that one participant's
12 non-compliance does not degrade reliability or increase
13 costs for other market participants.
14 Federal or state action mandating membership in
15 reliability councils and NERC or some other federal or state
16 mechanism will almost certainly be needed to equitably
17 administer the costs of maintaining reliability and ensure
18 compliance with the rules of the road.
19 In conclusion, restructuring will impact the
20 electric industry. That impact can be positive if all of us
21 involved in the restructuring process do it right the first
22 time.
23 Commercial pressures may stress the reliability of
24 the electric system. Consequently, we will need to ensure
25 that balance between competition and reliability is

1 maintained.

2 We need to move through restructuring in a prudent
3 and timely manner. However, we must manage this transition
4 with a critical eye if we are to be sure that there are no
5 complications that develop which will not impact our
6 objective of preserving reliability.

7 The ISOs being formed in the west will have a
8 responsibility to maintain system reliability, and as
9 members of WSCC, will play an important and essential role
10 in administering interconnected system reliability.

11 NERC and the regional reliability councils, as
12 self-regulating organizations, having the support of the
13 regulatory community must have the appropriate tools and
14 therefore ability to continue to effectively manage electric
15 system reliability.

16 No matter how dramatically the industry changes
17 and evolves, the public will expect and demand reliable
18 service. Mandatory compliance, reliability monitoring,
19 enforcement capability and accountability will be essential
20 for ensuring the public's desired level of reliability.

21 Thank you.

22 COMMISSIONER ROGERS: Yes, I was particularly
23 interested in your note that you're working to implement a
24 certification program. I wonder what your thoughts are
25 there with respect to what the significance of that

1 certification program might be.

2 It sounds to me like a very good idea and one that

3 might help to really ensure some uniformity in handling very

4 complex situations as they might develop any place in the

5 country.

6 Is this a program that you would think would be

7 applicable to all of the coordinating councils or just your

8 own?

9 MR. EYRE: No. In fact, my comment was that we

10 are working with NERC, with Mr. Gent's organization, to put

11 in place both a program which would accredit training

12 programs and certify system operators throughout the

13 country.

14 COMMISSIONER ROGERS: It sounds like a very good

15 idea. This is something -- the type of thing which we've

16 been very concerned about with respect to nuclear power

17 plant operators' training, and there are some good models, I

18 think, within the nuclear industry that -- NPO for instance,

19 Mr. Nye is very familiar with, that might be helpful to you

20 there in carrying that out.

21 CHAIRMAN JACKSON: Commissioner Dicus?

22 Commissioner Diaz?

23 Commissioner McGaffigan?

24 Mr. Delgado.

25 MR. DELGADO: Thank you very much, Dr. Jackson,

1 Commissioners. I am director of electric system operations
2 for Wisconsin Electric and I would like to tell you what
3 that means. I'm responsible for every aspect of
4 transmission service, the control center, construction,
5 planning, protection. My background is power plant
6 operations, all fossil though.
7 I would like to begin with a rather
8 uncontroversial statement. I would say that deregulation
9 will not impair transmission security. In my brief comments
10 here, I hope to be able to --
11 CHAIRMAN JACKSON: You say that was a
12 controversial statement?
13 MR. DELGADO: No. I said uncontroversial but I
14 suspect that you might not totally agree. I hope to be able
15 to back up the statements to give you a sense that this is
16 not genetic optimism, but in fact there are very valid
17 reasons to believe so.
18 First, let's begin with two provisions. The first
19 one is that the consequences of unreliable electric supply
20 -- incidentally, I appreciate Commissioner Rogers' comments
21 regarding the terminology, and I did select the terminology
22 very carefully here because I think it will add clarity to
23 the subject and I think it will help the Commission identify
24 its objective.
25 As I was saying, the consequences of unreliable

1 electrical supply which are -- you can conceive are frequent
2 burnouts and rotating blackouts, are not acceptable to the
3 North American customers. This is, to us, assurance that
4 there will be a continuous motivation and incentive and
5 that, in fact, will be powerful.
6 Second, the physical reality of an interconnected
7 electric network will not be changed by either deregulation
8 of the industry or by the growth of competition. The power
9 plants will move, and frankly, from the perspective of
10 physics, it will look very much the same.
11 I will add to it that from every aspect, I would
12 predict that transmission service will continue to be a
13 regulated monopoly. I do not think that anybody can
14 conceive of building a parallel competitive system, and to
15 me, that's the definition of a natural monopoly.
16 Besides, there is, I would say, a very solid
17 consensus in the industry about the necessity to maintain
18 reliability. To a greater or lesser degree, all portions of
19 the transmission network support each other.
20 At a transmission level, all users using an
21 interconnected network share the same reliability. No
22 individual transmission owner can choose to build, maintain
23 or operate its system to a lesser reliability level without
24 affecting other entities within the interconnection.
25 There is no alternative to keeping a high degree

1 of transmission network reliability. Practically speaking,
2 the reliability of the network is the highest reliability
3 available to any single user. Obviously at a distribution
4 level, other things can be done.
5 Security and adequacy are two aspects of
6 reliability which will help to explain the issue here. The
7 NERC definitions are at the end of the document but I would
8 like to rephrase them.
9 A transmission network is secure if it operates
10 within adequate voltage and frequency margins and survives
11 contingencies without cascading failures. It is adequate,
12 however, if it in fact is able to meet the needs of the
13 customer with the level of assurance the customer thinks
14 they need.
15 The electric system operation is the epitome of
16 real time. Either generation matches the electrical demand
17 or the demand must be reduced to match the generation by
18 taking delivery. Any major mismatch of generation and load
19 will result in localized equipment overloads and low voltage
20 operation that could lead to equipment damage and cascading
21 system failures. This is like a primer in transmission
22 operations. If I drag you through it, I'm sorry.
23 If the whole interconnection, and you realize we
24 have three interconnections in North America, is overloaded,
25 system frequency would decay and that would lead even to

1 more sudden and wider disruptions of network operations
2 unless it is arrested, and of course we have the mechanics
3 to do so.
4 When a transmission system cannot deliver
5 sufficient generating capacity to meet the load demand,
6 system security will be maintained by disconnecting load as
7 necessary to balance the remaining demand with the
8 generating capacity so the transmission system can deliver
9 reliably at any particular moment.
10 Load reduction is achieved through the exercise of
11 curtailable contracts with customers, and I would say also
12 with appeals to the customers incidentally, which in fact it
13 can become very, very effective, and by rotating blackouts
14 after the demand side programs and appeals have been
15 exhausted.
16 From this perspective, rotating blackouts are
17 controlled actions of the operator in order to match load to
18 generation when generation is not enough to meet the load.
19 These are not failures of the transmission system. Such
20 actions are directed at the prevention of equipment damage
21 and black plant shutdowns which have a high potential of
22 costing our plant equipment damage, and of course that means
23 that we would have then long-term problems.
24 Unfortunately, the distinction would seem
25 irrelevant to the end user, but it's extremely significant

1 for the maintenance of long-term adequacy. It is also at
2 the heart of this Commission's concern with electric
3 reliability's impact on the safety of nuclear power plants.
4 So electric system operators have the means to
5 assure security even when the system is not adequate. These
6 means include computer-based controls and communication
7 systems which all control areas have. These are the energy
8 management systems, or EMS, whose procedures, the training
9 and the necessary authority to take appropriate actions, and
10 I would like to just on the side say that once a year, the
11 chief operating officer of each company in Wisconsin sends a
12 letter to the operators reminding them that they have all
13 the authority required to keep the system secure, including
14 dropping firm load. They do not have to request permission
15 to do so. And it is renewed. We try to renew it once a
16 year, make sure everybody knows about it.
17 All of the more persuasive scenarios being
18 proposed for deregulation of the industry recognize the
19 imperative necessity of retaining the system operator's
20 focus on electrical security. An adequate system, on the
21 other hand, must secure by necessity, because there's no
22 adequacy if the system cannot stay on.
23 Long-term system reliability, both adequacy and
24 security, are the result of appropriate transmission and
25 generation planning. Generation planning is directed at

1 meeting the projected demand growth in the most economic
2 fashion.
3 Transmission planning, in turn, is traditionally
4 intended to connect generation to load and it has been said
5 already here several times. It also is intended to increase
6 reliability at the least cost by promoting the sharing of
7 generation resource margins across the interconnection.
8 In a competitive electricity market, the entities
9 with contractual or regulatory obligation to serve end load,
10 and I'm not specifying what that might be because there is
11 no need to specify it -- there are many possible outcomes --
12 they will provide the necessary generation, and I say
13 transmission resources through firm contracts. In other
14 words, they will assure that there is sufficient firm
15 services in order to meet the obligations of the load that
16 -- meet the load that they're obliged to serve.
17 If those resources are not sufficient to meet the
18 demand obligation, system operators will be able, as they
19 are today, to maintain the system energy balance with the
20 traditional means already noted using curtailable contracts
21 and ultimately implementation of rotating blackout.
22 As I repeat, rotating blackout is in fact the
23 ultimate goal. I do not want to give you the impression
24 that we look forward to using it.
25 I say that regional transmission planning will

1 improve long-run adequacy and security by removing
2 constraints. Two of the most widely expected developments
3 for the near future of the electric industry are original
4 transmission planning and the establishing of grid wide
5 tariffs that eliminate the stacking or pancaking of
6 transmission costs for generation located for most of the
7 load. I would say of course that we also expect regional
8 operations is very much in the near future.
9 Regional planning will facilitate the elimination
10 of transmission congestion, even though the most economic
11 solutions often span jurisdictional and property lines, and
12 I can assure you that the transmission limitations affecting
13 the state in which I live, Wisconsin, are not in Wisconsin.
14 I had to explain that to the governor last Monday because he
15 wanted to do something in a hurry, and I'm sorry. Actually,
16 they're outside of Wisconsin, so we had to work through the
17 region in order to remove them.
18 Grid-wide tariffs, in turn, should promote the
19 shifts and deciding of new generation locations that expand
20 rather than constrain transmission facilities. This would
21 improve the effectiveness of the existing transmission
22 system.
23 And of course proper location of transmission can
24 expand transmission capability -- I mean, proper location of
25 generation can expand transmission capability, and of course

1 the fact that the cost is in different locations for
2 transmission service will improve the -- will motivate the
3 proper location of generation.
4 In varying degrees, all regional councils have
5 achieved some coordination of the operation and planning of
6 transmission systems. Obviously if the council involves a
7 pool, there is more coordination.
8 The main area, of course, is not a pooled area.
9 However, there is coordination.
10 The push for greater integration of regional
11 operations is urged by the rapidly increasing number of
12 entities transacting the transmission network.
13 Let would say that before the EPACT of 1992, we
14 probably transacted with six entities, which we were
15 directly connected to. Right now the list is probably
16 upwards of 50 or 60 of them.
17 Many of us are convinced that regardless of the
18 process of deregulation, there's already a need for
19 independent regional system operators with real time
20 information and authority over large areas of the
21 transmission network. And I could illustrate that if you
22 had any questions about it.
23 Wisconsin Electric, me personally, is
24 participating with other Wisconsin and Minnesota utilities
25 in information of what we call the upper Midwest ISO. This

1 was an ISO filed with the FERC last October by the Primergy
2 applicants, but it was put together with the assistance of a
3 variety of Wisconsin and Minnesota companies.
4 We also are participating with 25 other
5 transmission owners in forming the Midwest ISO which should
6 be filed with FERC this year. The structures of the ISOs
7 are compatible. The Midwest ISO goes from West Virginia
8 through Ohio, Pennsylvania, all of Indiana, Illinois,
9 Missouri, Wisconsin, Michigan. I don't want to forget
10 anybody.
11 The efforts should result in one very large entity
12 responsible for transmission operation and planning over a
13 vast portion of the Midwest.
14 Some of the key features included both in the
15 upper Midwest and the Midwest ISO proposals, and just to
16 refer to some of the comments I already made here, it will
17 have real time information over the broad area of the
18 network. The whole area will have information on it.
19 It will have authority over all transmission
20 operations including the dispatch of generation to assure
21 network security, would produce a regional transmission
22 plan, will operate within rules set by reliability councils
23 and regulatory entities.
24 So the ISO will not set its own rules. It will
25 operate within the rules that are given to it by the

1 councils and by the regulators.

2 Transmission owners will maintain responsibility
3 over local system conditions, over hands-on maintenance and
4 operation of their equipment under the authority of the ISO,
5 and I would say these last two features, the fact that the
6 rules given to it, and they do not -- and the ISO will not
7 develop its own rules, and the fact that the transmission
8 owners under the ISO will still remain in control of the
9 hands-on operation should give some comfort to this
10 Commission.

11 The ISO will uphold all special reliability
12 requirements and priorities of generating plants and large
13 load centers, and there are a variety of them and I would
14 assure you that the text we are working on in the Midwest
15 ISO does say that and in fact it will refer specifically to
16 nuclear power plants.

17 This would include the technical specs of the
18 nuclear power plants. These requirements will be identified
19 with plant owners and/or operators and it will become a part
20 of the ISO procedures.

21 I would like to address just briefly the training
22 -- the basis of system operations just to illustrate a
23 little bit of what goes on in system operations.

24 Electric system operations for Wisconsin is
25 typical of transmission groups throughout the Midwest.

1 There are 13 systems supervisors. These are fairly well
2 paid, highly trained individuals.
3 These employees perform the transmission
4 operations and generation dispatch functions around the
5 clock seven days a week from the system control center that
6 we have west of Milwaukee. There is an on-line backup
7 center in Appleton, so all the computer software, all the
8 communication is doubled up so in case there's a failure,
9 the backup can in fact take over operations.
10 The energy management system monitors special
11 reliability requirements. Nuclear plant requirements are
12 built into the EMS display. There is voltage monitoring and
13 there's voltage alarms that allow the operator to know, and
14 those are set to the limits within which the power plant has
15 to be. Likewise, there are operating procedures which are
16 built into the computer displays so that the operators in
17 fact bill them out for consultation as necessary. There are
18 also paper procedures that back that up.
19 The system supervisor is selected from a variety
20 of work backgrounds that include plant operations, both
21 fossil and nuclear. We have them from the military, but
22 also from the nuclear power plant, electrical design
23 employees, protection, planning, and startup.
24 This variety is put to use in the development and
25 revision of operating procedures and in the process of

1 cross-training the group, which is an ongoing effort.

2 On the job training, with the use of procedures

3 under the supervision of an experienced employee -- and this

4 is the way we bring the new employee -- forms the core of

5 the training program.

6 However, the Wisconsin companies perform joint

7 training of system operators through the WUMS, what's called

8 WUMS, Wisconsin, Upper Michigan System, system operator

9 training, and the purpose of this is that it in fact allows

10 that all the operators in fact work together even though

11 they're in different companies to learn the same basis and

12 it's a lot of practical information they learn together.

13 We are in the process of revising that and we

14 should have that coming up this year and be able to restart

15 that whole effort.

16 And I would say that future NERC operator

17 certification would provide greater nationwide uniformity to

18 train system operators, and we look forward to it. In

19 addition, NERC and Maine, though NERC has requested it, has

20 completed the certification of control rooms to make sure

21 the control rooms in each control area have the adequate

22 elements to be able to do the job.

23 You asked, if you want to, for a legal background.

24 Would you like me to comment on it?

25 CHAIRMAN JACKSON: Sure.

1 MR. DELGADO: We think there is a need for some
2 legal backdrop or some legal action. For one thing, we
3 think it's very important to finally clarify among the
4 agencies of the government who has the authority over
5 reliability, and as we stated earlier, that is somewhat
6 vague.
7 We think it is important to make very clear that
8 all entities using the network must follow the same rules,
9 and that means jurisdictional as well as non-jurisdictional,
10 and that is not clear to date, even though I will have to
11 add that non-jurisdictional entities by and large do belong
12 to the NERC regional councils.
13 We also have to keep in mind that we're talking
14 about the North American grid. Canada and Mexico are an
15 integral part of it, and it is important that whatever rules
16 we agree to, and of course they participate in NERC, that
17 they do too, and so the sense of obligation and
18 participation is something that may require government to
19 government dealing. It has to be clarified.
20 And then ultimately, we are of the opinion that
21 regional operations in fact is a necessity and ultimately,
22 even though it should not be specified as how to do it, it
23 should be a very strong indication, either through law or
24 regulation, that all entities must participate in regional
25 operations, and that of course is controversial, I have no

1 doubt.

2 CHAIRMAN JACKSON: Thank you. I think I'm going

3 to go on to Mr. Nye and then we'll take any commissioner

4 questions.

5 MR. NYE: Thank you, Chairman Jackson. I would

6 say in view of the lateness of the hour and our physical

7 physique is maybe affecting our mental acuity, I will seek

8 to try to summarize as best I can and not try to repeat what

9 has been said here today.

10 I am president and CEO of Texas Utilities Company,

11 a large integrated utility in Texas. That is the

12 owner/operator of a large nuclear power plant, and I am also

13 currently vice chairman of NERC and a member of the DOE

14 Reliability Study which has been referenced previously.

15 If I could simply ask you to refer to the remarks

16 that I've provided you previously, and I'll seek to try to

17 sort of summarize from some notes I've made as I sat here.

18 I think it's clear that restructuring, and in some

19 degree deregulation, can impact reliability of the grid

20 negatively. Restructuring will likely change the

21 traditional way the grid is used. That is, more users, more

22 heavily loaded circuits and the like. If we are to maintain

23 traditional reliability of the grid, it will require some

24 vigilance, various steps and some precautions.

25 Markets offer many benefits, but markets also may

1 operate in dynamic stress with reliability. Grids are not
2 perfect and we should keep that in mind. They have not been
3 perfect in the past, nor will they be perfect in the future,
4 but the record today, particularly over the last 30 years,
5 is pretty exceptional.
6 My view is that the current reliability of grid is
7 good, and I will say that recognizing that as we leave this
8 meeting, there may be an incident, and so notwithstanding
9 the fact that there will be from time to time operating
10 circumstances that are and will be of concern.
11 The question really is the question that the
12 Chairman asked at the very outset, and that is, will the
13 reliability of the grids be maintained as the industry
14 changes?
15 In that connection, I think it is helpful, at
16 least I found it helpful, to divide this issue into two
17 halves, the one-half being the supply and what we've tended
18 to think of as an infinite supply of electricity always
19 available to everybody who wishes it on short notice.
20 I think as to the supply, we've got to depend on
21 the market. I think markets do provide adequate responses
22 to consumer needs, but when I studied economics 101, there
23 was a proviso there. It said, markets respond to consumer
24 demands over time. And so that at any one time, the supply
25 may or may not be adequate under a market condition, and I

1 think some customers will choose to buy under less than
2 optimal conditions, some customers will choose to secure
3 supplies that are very reliable, very dependable, and in
4 connection with their particular need.
5 So if we can set the supply on one side and the
6 grid on the other side. The grid is reliable. The grid can
7 be maintained, very reliable in the future, providing that
8 we ensure certain provisions.
9 As a part of that reliability, I think it is clear
10 that security coordinators, and they are variously referred
11 to as ISOs and RTGs and councils and what have you, but
12 there is a function that must be performed someplace that
13 sets the security of the grid above all other considerations
14 that does not deal with the market considerations and that
15 does not deal with the equity of someone's economic
16 position, and that is the essence of what I think -- when I
17 talk about an ISO or security coordinator, that I'm looking
18 for and I am seeing.
19 My view is that NERC, reconstituted and renewed,
20 provides the best vehicle for securing the reliability of
21 the system. I do believe that NERC and NERC standards can
22 be developed by full participation by all players in the
23 industry, all the new players, as well as the traditional
24 players, and that those protocols, reliability standards and
25 so forth will require either governmental or regulatory --

1 legislative or regulatory backup.

2 I think there's precedent for that sort of thing
3 in the way we operate the securities markets in this
4 country. The government has seen fit to allow the market to
5 work to its fullest extent and to allow self-help agencies
6 to conduct very serious and critically important activities,
7 commercial activities, and yet the government always
8 provides some backup and some assurance that the sanctions
9 and the incentives that are provided by the commercial
10 market do have a backup in the event that there is a failure
11 in that regard.

12 I am anxious to make the point that the work that
13 NERC is doing is more in the nature of renovation. It is
14 not in the nature of basic construction, and you asked
15 earlier, Chairman Jackson, what confidence do we have that
16 these new standards will be all right. I think we've got 25
17 or 30 years of experience under generally those kinds of
18 standards, those kinds of protocols, those kinds of
19 expectations, and the changes that are being made are
20 changes that are being made to accommodate more players
21 under a more rigorous circumstance.

22 In that connection, I do think that the ISOs are
23 developing along the right lines in this country, that is,
24 the security coordination function, and I do think we need
25 to be careful about the definition when we talk about what

1 an ISO is.

2 I'm pleased to report that ERCOT has a broad

3 governance-based ISO, and in connection with all of the

4 ERCOT standards, I'm very pleased to tell you that as has

5 been traditionally the case in all the regions with which

6 I'm familiar, the nuclear power plant needs and criticality

7 is treated as the first and foremost consideration.

8 I think as we develop improved ISOs or improved

9 security coordination agreements, that nuclear power plant

10 needs will be recognized as a high priority.

11 I think there are six key elements for

12 transmission grid reliability and I'll speak to them very

13 quickly. Mandatory reliability protocols applicable to all

14 market participants with sanctions for non-compliance.

15 Security coordinator oversight for the big picture

16 on the regional or broader basis.

17 Monitoring of operations in real time to ensure

18 compliance.

19 Authority of an ISO or a security coordinator to

20 be responsible for security to implement corrective measures

21 as needed to ensure reliability.

22 Complete sharing of reliability analysis and data

23 around the market, and competent system operators, and

24 that's been referred to previously.

25 I think that everyone must recognize the

1 potentially serious consequences of core damage due to loss
2 of off-site power. I do believe that the NERC reliability
3 criteria focuses on keeping the grid reliable, operating
4 above security and contingency limits and always leaving
5 margins available to assure grid reliability.
6 Nuclear power plant reliance on secure
7 transmission grids is recognized by owner/operators and it's
8 important that everyone involved with the industry
9 restructuring be extraordinarily sensitive to this
10 requirement.
11 I do believe that regulatory and legislative
12 bodies must give priority attention to the reliability needs
13 of nuclear power plants, to the many reliability-dependent
14 customers, and to the importance of a highly reliable
15 electric supply system to the Nation's economy.
16 I think I would conclude simply by saying that I
17 think we can manage this well. I think we can accommodate
18 the new market players, and I think we can accommodate a
19 major paradigm change in the traditions of the industry, but
20 I don't think it will happen unless we are vigilant about
21 it, unless we take the precautions that are appropriate.
22 CHAIRMAN JACKSON: Thank you. What I'd like to do
23 is I have a couple of questions and you can tell me in
24 answering them if in a certain sense they have been
25 addressed already.

1 I'd note that you were saying the best prospect
2 for assuring reliability is the enhancement of the NERC
3 organization. Do you mean along the lines that have been
4 already discussed or are there some other specific?
5 MR. NYE: There are probably shades of gray
6 between the speakers I heard today as to what they would
7 expect with concern to NERC. I think there is perhaps on
8 the part of DOE, and I won't speak for David, but I think
9 there is perhaps a concern and I think probably so, that
10 there not be a continuation of some narrow focused group of
11 players that determine standards, and I think NERC is in the
12 process of delivering a governance which will assure that
13 all the players have full participation in not only the
14 enhancement of the existing standards, but the confirmation
15 that those standards are appropriate, and I do believe they
16 are appropriate and I do believe they will stand the test of
17 time.
18 But with that one qualification, and understanding
19 that it is natural, given that the players who have run the
20 reliability system, the grid system in this country for so
21 long have come principally from the traditional electric
22 utilities, the investor owned, the federal agencies, the co-
23 ops, the munis, but not the IPPs and not the marketers, and
24 those folks have to have an equal participation.
25 Given that in the governance, I think the

1 reliability standards that come out of NERC give us the best
2 shot. We've been at that for 30 years. It doesn't stand to
3 reason that we would start over trying to establish a whole
4 new set of standards and practices, but rather to fix the
5 ones we've got to ensure that everyone is treated fairly and
6 that the market is not encumbered by the absolute necessity
7 to maintain the reliability of the grid.
8 CHAIRMAN JACKSON: You think by having this
9 restructuring and empowerment of NERC, that would also
10 address the question about movements of power between grids?
11 Because there is an issue, you can take care of your own
12 regional network, but you could have internetwork movement
13 of power wheeling.
14 MR. NYE: Yes, Dr. Jackson. I do believe that the
15 only hope for interregional conduct is through some national
16 organization, some national standards, such as NERC, and
17 certainly we have all the experience with NERC and I can't
18 imagine that we would seek as a nation, through changing the
19 public policy, the way we run our utilities to start over
20 with a system that essentially is prepared to handle that
21 problem.
22 CHAIRMAN JACKSON: And do you think that NERC's
23 reliability criteria should have a direct linkage to NRC
24 criteria or not?
25 MR. NYE: I think that the NRC has to be satisfied

1 that whatever system is put in place that the public policy,
2 the Congress, and the state legislators will evoke, that
3 they have to be satisfied that it works.
4 Whether or not the NRC needs to be an active
5 player in each of those activities, I would rather doubt.
6 I'm a little bit back to what Dr. Rogers said, which is, we
7 have to, at the NRC, take for granted what is out there.
8 Now, certainly we ought to -- we. You all ought
9 to be a party to the public policy debate and it seems to me
10 that holding up reliability as a critically important
11 element in nuclear safety is likewise parallel to the equal
12 concern that many high, high reliability customers that
13 require critical reliability or are depending on -- I'm not
14 saying this very well, but the concern you have about
15 nuclear power plants having adequate off-site power is
16 shared by a number of electronics and computer and other
17 manufacturers that must have a high degree of reliability
18 all the time.
19 And it is also necessary for the economy of the
20 nation. I don't think we're about to jettison the feeling
21 that we need to have the most reliable electric power system
22 in the country, and I'm sure DOE doesn't intend that, nor
23 does FERC. We're all working towards accommodating a new
24 market consideration consistent with the traditional
25 reliability that we have come to enjoy.

1 CHAIRMAN JACKSON: Thank you.

2 Commissioner Rogers.

3 COMMISSIONER ROGERS: Well, just I listened very

4 carefully to your remarks and read them. I wasn't sure

5 though whether you felt that some kind of federal

6 legislation was desirable here or not.

7 MR. NYE: Well, it's probably against my interest

8 to say so. But I do believe in due course some sort of

9 federal legislation as it relates to regulatory sanctions

10 may be necessary.

11 I do believe that states and local governments

12 should act first, and generally I'm inclined to think that

13 government closest to the people is best, but this is a

14 national issue. It involves a national market, perhaps an

15 international market, and therefore I think some sort of

16 minimal enforcement standards that does not intrude upon the

17 market or does not try to conduct a command and control type

18 philosophy will be necessary.

19 I don't think that's imminent. I think that can

20 happen in three or four years, once this plays out and we

21 really understand what sort of a market we have and what

22 sort of a problem we have.

23 I do believe that it's better to have a self-help

24 industry group composed of all the players bring forward

25 standards that do the least damage to the market, that

1 inhibit the market the least amount, and yet absolutely
2 ensure for all the players, not only the NRC but others,
3 that this will deliver a highly reliable grid system upon
4 which we can rely.
5 COMMISSIONER ROGERS: Thank you.
6 CHAIRMAN JACKSON: Commissioner Dicus.
7 COMMISSIONER DICUS: One quick question, please.
8 And this is a question that Mr. Wolff responded to from the
9 Chairman. It had to do with whether we know with some
10 reasonable certainty what the floor is with regard to grid
11 voltage and frequency or any combination of the two below
12 which we shouldn't go because we know at that point that we
13 would have some grid instability situations, and you said
14 yes, and for your council, you knew what the number was and
15 you were prepared to deal with it.
16 So my question is probably to you. Is this the
17 case across all the councils across the entire systems? Do
18 we know what that is and are we prepared to deal with it?
19 MR. WOLFF: It's generally coordinated in the
20 three interconnections. It's different in each one. I
21 think you can see the reason why, Texas being smaller than
22 the east.
23 CHAIRMAN JACKSON: But Texas is its own country.
24 MR. NYE: Great nation, Texas.
25 MR. GENT: There are uniform requirements in the

1 various interconnections for different levels of frequency,
2 unit response. This goes right down to the basic individual
3 generating unit, how it responds to the load, where load is
4 shed under frequency, how low the different voltage steps
5 should be, how it's tested. This is all very uniform.
6 MR. NYE: If I could offer an alert, an alarm or a
7 concern as a long-disqualified engineer, there's one thing
8 to say we know what the standards are and what the limits
9 are and what the conditions are that we need to seek.
10 It's quite different to imply by that that we
11 understand all we need to understand about the concepts of
12 voltage collapse which have developed in some of these
13 dynamic situations. It's quite a different matter to talk
14 about a steady state condition for which we can plan and
15 which we seek to control and it's quite another to try to
16 anticipate the myriads of millions of different operating
17 conditions that may fall upon Bob or anyone else at any one
18 time and tell you or assure to you that voltage collapse is
19 not a problem, because it is sort of the current concern in
20 the industry, I think. And the more we load the lines and
21 the more we expose the system to unanticipated flows, the
22 more likelihood it is that we're going to have some
23 conditions that we did not anticipate.
24 So we need to be able to control even under the
25 circumstances of unanticipated demands, and I think that's

1 perhaps the backup we need to all assure ourselves of.

2 CHAIRMAN JACKSON: Commissioner Diaz.

3 COMMISSIONER DIAZ: No questions.

4 CHAIRMAN JACKSON: Commissioner McGaffigan.

5 COMMISSIONER McGAFFIGAN: No questions, but it

6 looks like Mr. Wolff wants to get in the last word.

7 MR. WOLFF: I was just going to make one comment,

8 that I can understand the concern of the Commission about

9 how seriously we take the nuclear plants and their supply,

10 but when you stop to think of it, all the operators out

11 there have wives and children in the area and all the

12 operators -- speaking from an area that is relatively short

13 of nuclear power right now, I can tell you that we've missed

14 nuclear power and we would do nothing to jeopardize it in

15 the long run.

16 The other thing I thought I might leave you with

17 is the cost of an ISO, our ISO costs the ratepayer in New

18 England on average 16 cents a month. So it's too cheap to

19 meter to use in the whole place.

20 CHAIRMAN JACKSON: No. I thank you, I thank all

21 of you. I appreciate that your wives and children live in

22 the area. So do we all, as do our nuclear operators. We

23 regulate them any way.

24 But I would like to thank the NRC staff, the DOE

25 representative, the coordinating council, reliability

1 council representatives, and the industry representatives
2 for a very informative briefing to the Commission on this
3 subject of electric grid reliability and security and its
4 potential impacts coming out of electric utility
5 deregulation but potentially -- particularly with respect to
6 the security and safety of the nuclear plants.
7 As I stated in a speech to the National
8 Association of Regulatory Commissioners in January, from the
9 NRC perspective, we've said that deregulation has to proceed
10 with a sensitivity to and an understanding of the
11 vulnerability of nuclear plants to loss of off-site power,
12 and that grid reliability governance structures and
13 operating criteria must reflect this, and it's an important
14 issue to be considered in the formation of independent
15 system operators.
16 And that this implies again that the standards of
17 performance, operational criteria, and the training of
18 personnel, which we've all spoken to today, are critical
19 oversight issues that have to be factored in and properly
20 addressed as deregulation goes forward.
21 I hope that in bringing you gentlemen here, that
22 we have sensitized you to the NRC's issues and concerns, and
23 those of you who are our direct licensees understand that
24 and are as sensitive to it as we are to start with.
25 But I'd like to make a couple of comments relative

1 to each presentation that we've heard today.

2 With respect to the staff presentation, I think

3 it's very important that we understand how the issue is to

4 be addressed within our current regulatory context,

5 understanding where we are and what we control versus what

6 we do not, but how it is to be addressed in these issues of

7 licensing basis, et cetera, and I've already spoken to the

8 issue of the timeliness and the expeditiousness of your

9 reviews, and I'm also going to be asking the AEO to arrange

10 for each region to have someone come -- go to a power pool

11 and a reliability council for that region to get themselves

12 more informed than I think our staff currently is today.

13 On the federal level more broadly, it strikes me

14 that there are parallel paths for the NRC and the

15 interagency process doesn't always work as well as it

16 should, and typically, when one agency goes to see another

17 -- and we do the same thing -- we would say, well, of

18 course, you know, if you want to be in, you're welcome to be

19 in, but the way to really be in is to make the interagency

20 process work and to have all the players, just as we've

21 spoken about it in the broader context, at the table as the

22 discussions go on.

23 And I'm going to be meeting with the Secretary at

24 any rate and I'm sure we'll talk about this point.

25 I think that we will be prepared and I will be

1 prepared to speak to any legislation as appropriate within
2 the context of our concerns that reinforce the ability to
3 ensure that the issues are appropriately dealt with,
4 including testifying if it comes to that.
5 And with respect to NERC and the other regional
6 councils, I think the issue of -- the path that you're
7 proceeding down seem oriented, but it all has to address
8 these issues, but it really does have to be pulled together,
9 and that your operating protocols and the training of people
10 are, to us, very serious issues, and the compatibility of
11 what you lay out in terms of operational criteria to nuclear
12 power plant requirements and having some enforceability of
13 that, I think, is a very important issue to us.
14 And then with respect to the industry, I think
15 it's important that we have a clear understanding with
16 respect to the extent to which you feel the various
17 operating protocols that are being developed in fact are
18 compatible with the requirements on the nuclear plants, as
19 well as getting input from you on how you think the issues
20 can be addressed within the licensing basis or FSAR space
21 since that is something that the Commission has under
22 consideration at any rate as we go along.
23 And so unless there are further comments or
24 questions from fellow commissioners, adjourned.
25 [Whereupon, at 4;25 p.m., the briefing was

1 adjourned.]

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Electrical Grid Reliability
Comments to the
Nuclear Regulatory Commission
by
Erle Nye,
President of Texas Utilities Company
April 23, 1997

Electrical Grid Reliability
Comments to the NRC
by Erle Nye
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Good afternoon. My name is Erle Nye and I am president and CEO of Texas Utilities Company, a large electric utility holding company, which owns and operates the Comanche Peak nuclear plant. I also am currently serving as vice-chairman of NERC and as a member of the DOE Reliability Task Force and the EEI CEO Steering Committee on System Reliability.

I appreciate being asked to provide comments to the Commission regarding electrical grid reliability. I commend Chairman Jackson and the commissioners for calling this meeting. Thank you for the opportunity to assist the Commission in formulating its views regarding industry restructuring.

Restructuring, and to some degree, deregulation potentially could impact grid reliability. Maintaining the current high standards of interconnected grid reliability in the industry will require attention. Restructuring of the industry will change the traditional way of delivering electric energy. As the industry transitions:

- The traditional vertically integrated electric utility industry will tend to disaggregate.

- Generation in many jurisdictions will be provided by a market (vs. regulation) on either a wholesale or retail basis and generation options will continue to change as more independent power suppliers enter the evolving wholesale markets.

- Transmission will continue to be regulated, as will the delivery portion of distribution. However, transmission grids will be used differently than the purposes for which they were originally designed and built.

- Energy supplies and purchases will have different degrees of reliability according to customer requirements.

- The security function related to controlling the transmission system typically will be operated separately from the energy marketing function.

These anticipated changes need not jeopardize service reliability nor impact the traditional reliance of nuclear power facilities on the grid, provided steps are taken to ensure the security of the transmission system. The electrical transmission grid can retain its traditional reliability provided several measures are taken.

- The best prospect for assuring reliability is the enhancement of the NERC organization.

- NERC must change to accommodate participation by all key participants in the restructured industry on a fair basis.

- All users of the transmission system must be obligated to conform to operating practices that secure the system.

- Regulatory bodies must support uniform policies, standards and practices promulgated by NERC.

Traditional NERC reliability policies, standards and compliance measures are being reconstituted and developed.

- NERC has created a requirement that Regional Security Coordinators have responsibility for the security and reliable operation of the grid. The model allows flexibility as to which entity in the restructured industry is responsible for carrying out the function.

- Functional responsibility for grid reliability is being established within a structure of governance that ensures compliance with established reliability policies and standards.

- Voluntary compliance with NERC Transmission Grid Reliability

Policies and Requirements are changing to mandatory compliance for all market participants with incentives and/or sanctions to ensure compliance.

- NERC oversight will involve real-time monitoring of system operations for compliance with reliability protocols/standards.

- NERC is developing training and certification programs for system operators.

The Independent System Operator (ISO) concept is evolving to meet different needs and criteria as the industry restructures.

- In ERCOT, the newly formed ISO incorporates the NERC security coordinator function providing oversight for interconnection reliability. Control and dispatch of the transmission grid remains the responsibility of the transmission owners. Governance affirms adherence to NERC Policies for Grid Reliability. ERCOT Operating Guidelines adopted by its Board and administered through the ISO establish criticality of nuclear plants relative to off-site power. The Control Area's emergency plans and black start plans incorporate ERCOT's Guide III which also addresses the criticality of nuclear plant off-site power. "Independent" in the ERCOT ISO does not mean <u>independence</u> of grid operations from the transmission owner, but rather means <u>independence</u> of the wholesale merchant functions

from grid operation.

- The ERCOT ISO is working well, with full participation by all economic interests. All players are participating in its governance and advisory structures. Reliability remains the highest priority.

- The governance structure of the California ISO specifically addresses the criticality of nuclear plant off-site power. I am confident others also will address this priority in their governance.

The FERC is committed to maintaining high standards of reliability.

- A number of the ISO principles directly support the concept of system reliability. In Order No. 888, FERC expressly notes that the ISO's role in reliability matters "should be well-defined and comply with applicable standards set by NERC and the regional reliability council."

- FERC has signaled that it is not likely to relax Order No. 888 principles for ISOs to permit a lower priority on system reliability than exists today.

- It is my sense that Chair Moler and the other FERC commissioners

would desire an industry self-help organization like NERC, with full participation of all market segments, to provide a mechanism for ensuring reliability of the transmission grid while accommodating market requirements.

Nuclear plant safety requires reliance on a secure transmission grid.

- As the owner-operator of a nuclear plant and as the owner of a large interconnected transmission system, we recognize that the NRC General Design Criterion 17 (requiring an acceptably-designed nuclear power facility to include both an on-site electric power system and an off-site electric power system "to permit functioning of structures, systems and components important to safety") is of critical importance.

- Given the serious consequences of potential core damage due to a loss-of-offsite-power initiated event, all agree that high standards of grid reliability must be maintained. NERC's Reliability Criteria focuses on keeping the grid reliable -- operating <u>above</u> security and contingency limits and always leaving margins available to assure grid reliability.

- Nuclear plant reliance on a secure transmission grid is recognized by owner-operators and it is important that everyone involved with industry restructuring be extraordinarily sensitive to this requirement.

- In considering actions to restructure the industry, regulatory and legislative bodies must give priority attention to the reliability needs of nuclear plants, to the many reliability-dependent customers and to the importance of a highly reliable electric supply system to the nation's economy.

- The Public Utility Commission of Texas has recognized the importance of a reliable transmission grid to nuclear facilities in the development of the ERCOT ISO.

- I am encouraged by the FERC and DOE sensitivity to the importance of transmission grid reliability.

- All market participants have responsibility for maintaining reliability of the transmission grid. However, we realize the ultimate judgments for nuclear plant safety reside with this Commission.

It is clear that initiatives to restructure the electric utility industry create uncertainty regarding the reliability of the transmission grid. However, I believe that we can and must maintain a highly reliable transmission system. That can be accomplished through a strengthened NERC organization with the sanction and support of state and federal agencies. I appreciate the Commission's concern and attention to this matter.

Nuclear Regulatory Commission
Electric Grid Reliability

José M. Delgado -Wisconsin Electric Power Company

Deregulation Will Not Impair Transmission Security

A controversial statement? I think not, based on two observations:

First, the consequences of an unreliable electrical supply -- frequent brown outs and rotating blackouts -- are not acceptable to the North American electric customers.

Second, the physical reality of an interconnected electric network will not be changed by either deregulation of the industry or by the growth of competition.

•*Maintaining Reliability Is One Of The Few Areas Of Solid Consensus In The Industry*

To a greater or lesser degree, all portions of the transmission network support each other. At the *transmission level* all users within an interconnected network share the same reliability. No individual transmission owner can chose to build, maintain or operate its system to a lesser reliability level without affecting all other entities within the interconnection.. There is no real alternative to keeping a high degree of transmission network reliability because practically speaking, the reliability of the network is the highest reliability available to any end user.

•*Security & Adequacy Are the Two Basic Aspects Of Grid Reliability*

We need to talk about two, distinct aspects of reliability, namely: system security and system adequacy (see NERC definitions[i]).

Paraphrasing the official NERC definitions, a transmission network is secure if it operates within adequate voltage and frequency margins, and survives contingencies without cascading failures. Adequacy, on the other hand, is the ability of an electric energy delivery system to meet the needs of the end users with the high degree of assurance that end users expect.

•*The Transmission Network Can Be Secure Even If Not Adequate but It Cannot Be Adequate Without Security*

Electric system operation is the epitome of "real time". Either generation matches the electrical demand or the demand must be reduced to match the generation that can be delivered. Any major mismatch of generation and load will result in localized equipment overloads and low voltage operation that could lead to equipment failure and cascading system failures. If the whole interconnection is overloaded, system frequency will decay and lead to even more sudden and wider disruptions of network operations.

When the transmission system cannot deliver sufficient generating capacity to meet the load demand, system security will be maintained by disconnecting load as necessary to balance the remaining demand with the generating capacity that the transmission system can deliver reliably at any particular moment. Load reduction is achieved through the

exercise of curtailable contracts with customers, and by rotating blackouts after the demand side programs have been exhausted.

From this perspective, rotating blackouts are control actions of the operator, not failures of the transmission system. Such actions are directed at preventing transmission equipment damage and black-plant shut downs which have a high potential of causing power plant equipment damage. Unfortunately, this distinction may seem irrelevant to the end user, but is extremely significant for the maintenance of long term adequacy. It is also at the heart of this Commission's concern with electric reliability's impact on the safety of nuclear plants.

•*Transmission Operators Will Assure System Security*

So, electric system operators have the means to assure security even when the system is not adequate. These means include computer based control and communication equipment (Energy Management Systems - EMS), procedures, the training and the necessary authority to take appropriate actions.

All of the more persuasive scenarios being proposed for deregulation of the industry recognize the imperative necessity of retaining the system operators' (local as well as regional operation proposals) focus on network security. An adequate system, on the other hand, must be secure by necessity.

•*Market Participants Will Assure Adequacy*

Long term system reliability -- both adequacy and security -- are the result of appropriate transmission and generation (supply) planning. Generation planning is directed at meeting the projected demand growth in the most economic fashion. Transmission planning in turn is traditionally intended to connect generation to load. It also is intended to increase reliability at the least cost by promoting the sharing of generating reserve margins across the interconnection.

In a competitive electricity market, the entities with contractual or regulatory obligation to serve end load will provide the necessary generation and transmission resources to meet their obligations to serve end load. If those resources are not sufficient to meet the demand obligation, system operators will be able to maintain the system energy balance with the traditional means already noted by using curtailable contracts and ultimately the implementation of rotating blackouts.

•*Regional Transmission Planning will Improve Long Run Adequacy and Security by Removing Constraints*

Two of the most widely expected developments for the near future of the electric industry are regional transmission planning and the establishment of grid wide tariffs that eliminate the stacking (pancaking) of transmission costs for generation located remote from the load.

Regional planning should facilitate the elimination of transmission congestion, given that the most economic solutions often span jurisdictional and property lines.

Grid wide tariffs, in turn, should promote the siting of new generation at locations that expand, rather than constrain transmission transfer capacity. This will improve the effectiveness of the existing transmission system.

Grid Reliability Will Be Enhanced By Regional Operation And Planning

In varying degrees, all Regional Reliability Councils of NERC have achieved some coordination of the operation and planning of transmission systems.

The push for greater integration of regional operations is urged by the rapidly increasing number of entities transacting in the transmission network and the complexity of monitoring transactions across large distances and many participants.

Many of us are convinced that regardless the process of deregulation, there is already a need for Independent System Operators (ISO) with real time information and authority over large areas of the transmission network.

•*ISOs Being Developed in the Midwest:*

—Wisconsin Electric is participating with other Wisconsin and Minnesota utilities in the formation of the Upper Midwest ISO. It was filed with FERC last October by the Primergy applicants. We also are participating with 25 other transmission owners in forming the Midwest ISO, which should be filed with FERC this year. The structures of these two ISOs are compatible. These efforts should result in one very large entity responsible for transmission operation and planning over a vast portion of the Midwest.

— Some of the key features included in the Upper Midwest and the Midwest ISO proposals:

- Will Have Real Time Information Over Broad Areas of the Network
- Will Have Authority Over All Transmission Operations Including the Redispatch Generation to Assure Network Security
- Will Produce a Regional Transmission Plan
- Will Operate Within Rules Set By Regional Reliability Councils and Regulatory Entities
- Transmission Owners Will Retain Responsibility Over Local System Conditions and Over the Maintenance, and Hands-On Operation Of Transmission Equipment, Under the Authority of the ISO

These last two features are of special interest to this Commission. The ISO will uphold all special reliability requirements and priorities of generating plants and large load centers.

This will include the technical specifications of the Nuclear Plants. These requirements will be identified by plant owners and/or operators and will become ISO procedures.

System Operations In Wisconsin

The Electric System Operations group of Wisconsin Electric is typical of other transmission operations groups in the Midwest.

There are thirteen "System Supervisors" in the operations groups. These employees perform the transmission operations and generation dispatch functions, around the clock, seven days a week from the System Control Center in Pewaukee, Wisconsin. There is an on-line, back up center in Appleton, Wisconsin that can take over the operating functions in case of any emergencies disable the primary site.

The Energy Management Systems (EMS) Monitor Special Reliability Requirements. Nuclear Plant Requirements and Procedures Are Built Into the EMS Displays.

•*System Operators Have Wide Variety Of Background and Experience, Including Fossil And Nuclear Plant O&M*

The System Supervisors are selected from a variety of work backgrounds that include plant operations, (both fossil and nuclear), electrical design, protection, planning, construction and start-up. This variety is put to use in the development and revision of operating procedures and in the process of cross training among the group.

•*Operator Training will include the following:*

On the job training with the use of procedures under the supervision of an experienced employee forms the core of the training program.

Wisconsin companies perform joint training of system operators through the WUMS (Wisconsin Upper Michigan Systems) system operator training

Future NERC Operator Certification will provide greater nation wide uniformity to the training of the system operators.

MAIN Has Recently Completed the Certification of Control Rooms

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i

Reliability: The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system Adequacy and Security.

Adequacy: The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security: The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Nuclear Regulatory Commission
Electric Grid Reliability

José M. Delgado -Wisconsin Electric Power Company

(from the Glossary of Terms, Prepared by the Glossary of Terms Task Force, North American Electric Reliability Council, August 1996)

Response of Michehl R. Gent
President
North American Electric Reliability Council

Before

Nuclear Regulatory Commission
Meeting on Electrical Grid Reliability

April 23, 1997
Washington, D.C.

The following bullet items are points the Nuclear Regulatory Commission staff asked that I address. My responses follow:

- **Provide insight on what effect(s) deregulation will have on grid reliability.**

  NERC's purview extends to the entire interconnected bulk electric system — the high voltage grid that interconnects generators with load centers. NERC does not deal with the distribution system, which is typically the point of interface with the ultimate customer.

  Our primary motivation to address the reliability impacts of deregulation comes from the Federal Energy Regulatory Commission's Orders 888 "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities" and 889 "Open Access Same-Time Information System and Standards of Conduct." As part of our response to the Commission's Notice of Proposed Rulemaking, NERC presented a six-point action plan to ensure continued bulk electric system reliability. That action plan formed the basis for NERC's four Strategic Initiatives for Reliability, which are being implemented throughout North America.

  Of most interest to this Commission would be NERC's Strategic Initiatives dealing with Standards and with grid security. Security in NERC parlance means the ability of the grid to withstand sudden disruptions without losing its integrity. This requires maintaining a continuous balance between supply and demand and operating the system such that the loss of any one element (a generator, transmission line, or transformer) will not cause any other element to become overloaded.

  NERC has recently committed to establishing a network of 22 Security Coordinators, geographically and electrically distributed across North America. They will have their own dedicated frame-relay communications network, called the Interregional Security Network (ISN). The ISN will begin operation in June of 1997 with limited functionality. Several interim procedures will be put in place to handle any potential summer problems. The ISN will ramp up to full functionality later in 1997. Full functionality will include near real-time data flow between control centers and Security Coordinators, and among Security Coordinators. These 22 Security Coordinators will be responsible for conducting

routine security analyses of the grid, on-line, and have the authority to take any actions necessary to prevent or relieve overloads or potential risks to grid security. This elaborate system should allow many multiples of additional transactions over the existing transmission grid in a non-discriminatory manner while maintaining and improving reliability.

- **Discuss the Independent System Operator concept in the establishment of grid reliability governance structures.**

  NERC's Initiatives are based on separating transmission operations and reliability functions from the wholesale electricity merchant functions. For instance, the previously mentioned Security Coordinators are required to sign "data confidentiality agreements." Some of the real-time data that will be available to the Security Coordinators could be considered commercially sensitive. These data will be used only for security analyses and it must remain in the hands of those performing that function. In this sense, our "Security Coordinators" will be independent. Many believe this on-line security function will eventually migrate to the emerging independent system operators (ISO). Most ISOs are now in the fledgling state, but one purpose common to all will be to maintain grid reliability in accordance with establishing NERC, Regional Council, and other applicable reliability standards and criteria. These operators will be independent of the marketing function, as well as independent from any market participant. We do not expect the governance of ISOs to adversely affect on-line decision making for grid reliability. In fact, the lines of authority for maintaining grid reliability should be clarified and strengthened with the advent of ISOs.

- **Discuss the use of performance standards, operational criteria, training for individuals and systems established to maintain grid reliability as deregulation progresses.**

  Another of NERC's four Strategic Initiatives deals with Standards. Standards, the way we describe them, cover system performance, planning and operating criteria, and training. Activities in all these areas have been dramatically increased in preparation for the deregulation of electricity markets. We believe that a truly open market requires clearer Standards, Standards that can be quickly adapted to the needs of the market participants while maintaining reliability. For instance, in the area of training, we have recently committed to certification of "grid" operators and accreditation of Regional training programs NERC-wide, that is the United States, Canada, and Baja California, Mexico. This means that all "grid" operators will be certified as to their knowledge of reliability criteria and that all trainers of operators and their programs will be accredited so that we, and you, can be assured that their training courses will be sound relative to reliability. This project is in the development phase. We have just awarded contracts. If you would find it useful, we can provide you with all of this material that includes deadlines and check points.

  Our processes for developing Operating and Planning Standards have also been accelerated and are being changed to include more opportunity for input by all affected parties. Our Standards are becoming much more specific and measurable. We are also establishing uniform ways of judging performance to those Standards and have under way projects to determine how these Standards are going to be enforced. Regarding that enforcement, one possibility is that we will end up with what we are generically calling a "Reliability Compact," which will probably consist of a series of contracts that specifically obligate the parties to abide by the NERC Standards.

- **Discuss what factors and considerations are made in establishing grid reliability governance structures with respect to understanding nuclear power plant vulnerabilities to Loss-of-Off-Site-Power events.**

  Modeling groups in the Texas, Western, and Eastern Interconnections continually update databases to be used by Regional groups that run network studies. At the NERC level, there are general requirements for what these studies must consider. Locally, where nuclear power plant licensees have special reliability requirements, these criteria are included in the study parameters. Also, language is being included in some ISO agreements that requires ISOs to operate the grid in accordance with special operating criteria established by NRC operating licenses.

  You may also be interested in knowing that NERC is the home of a Generating Availability Database. This Database houses the performance and outage event records of the major generating units in the United States and Canada. At last count, we housed over 3,600 units including most of the nuclear units. Over the years, the requirements for the licensees to submit data has changed, so our data collection process for nuclear units has also changed. We are primarily interested in the types of data that will allow us to model a nuclear unit during either a transient or a slightly slower dynamic disturbance event.

NERC Operating Manual

North American
Electric
Reliability
Council

Operating Manual — Table of Contents

Operating Policies — Table of Contents

Section	Pages	Revision Date

Surveys	Period	Reference
Control Performance Criteria Survey	**Monthly**	Control Performance Criteria Training Document
Area Interchange Error Survey	**As needed**	Area Interchange Error Survey Training Document
Inadvertent Interchange	**Monthly**	Inadvertent Interchange Accounting Training Document
Frequency Response Characteristic Survey	**As needed**	Frequency Response Characteristic Training Document

Section	Pages	Revision Date
References		
Transmission Transfer Capability		May 1995
Electric System Restoration	**RESR:1–22**	April 1993
Monitoring Review Questionnaire	**RMWG:1–18**	January 1992
Backup Control Center	**RBUCC:1–18**	July 1993
Demand-Side Management	**RDSM:1–16**	December 1993

Policy 5 — Emergency Operations

Policy Subsections

	Effective
A. Coordination With Other Systems	
B. Insufficient Generating Capacity	
C. Transmission Overload	Effective December 31, 1996
C. Transmission System Relief	Beginning January 1, 1997
D. Separation from the Interconnection	
E. System Restoration	
F. Disturbance Reporting	
G. Sabotage Reporting	

General Criteria

When an operating emergency occurs, a prime consideration shall be to maintain parallel operation throughout the Interconnection. This will permit rendering maximum assistance to the system(s) in trouble.

Each system and control area shall promptly take appropriate action to relieve any abnormal conditions which jeopardize reliable Interconnection operation.

Each system, control area, and Region shall establish a program of manual and automatic load shedding which is designed to arrest frequency or voltage decays that could result in an uncontrolled failure of components of the interconnection. The program shall be coordinated throughout the interconnection to prevent unbalanced load shedding which may cause high transmission loading and extreme voltage deviations.

A. Coordination with Other Systems

[Appendix 7A — Instructions for Interregional Emergency Telephone Networks]

Criteria

A system, control area, or pool which is experiencing or anticipating an operating emergency shall communicate its current and future status to neighboring systems, control areas, or pools and throughout the interconnection. Systems able to provide emergency assistance shall make known their capabilities.

Requirements

1. **Notifying other systems.** A system shall inform other systems in their Region or Subregion, through predetermined communication paths, whenever the following situations are anticipated or arise:

    1.1. **System is burdening others.** The system's condition is burdening other systems or reducing the reliability of the Interconnection.

1.2. **Insufficient resources.** The system is unable to purchase capacity to meet its load and reserve requirements on a day-ahead basis or at the start of any hour.

1.3. **Lack of single contingency coverage.** The system's line loadings and voltage/reactive levels are such that a single contingency could threaten the reliability of the Interconnection.

1.4. **Emergency actions for inability to purchase capacity.** The system anticipates 3% or greater voltage reduction or public appeals because of an inability to purchase emergency capacity.

1.5. **Emergency actions for other reasons.** The system has instituted 3% or greater voltage reduction, public appeals for load reduction, or load shedding for other than local problems.

1.6. **Sabotage incident.** The system suspects or has identified a multi-site sabotage occurrence, or single-site sabotage of a critical facility.

2. **Hotline use.** When a condition is identified that could threaten the reliability of the Interconnection or when firm load shedding is anticipated, the affected control area shall utilize the Interconnection-wide telecommunications network in accordance with Appendix 7A — Instructions for Interregional Emergency Telephone Networks, Section 2, "Disseminating Information," to convey that information to others in the Interconnection. (Approved February 28, 1995)

B. Insufficient Generating Capacity

Criteria

A control area which has experienced an operating capacity emergency shall promptly balance its generation and interchange schedules to its load, without regard to financial cost, to avoid prolonged use of the assistance provided by Interconnection frequency bias. The emergency reserve inherent in frequency deviation is intended to be used only as a temporary source of emergency energy and is to be promptly restored so that the interconnected systems will be prepared to withstand the next contingency. A control area unable to balance its generation and interchange schedules to its load shall have the responsibility to remove sufficient load to permit correction of its Area Control Error.

A control area anticipating an operating capacity emergency shall bring on all available generation, postpone equipment maintenance, schedule interchange purchases well in advance, and prepare to reduce load.

Requirements

1. **Returning ACE to acceptable levels.** In the event of a capacity deficiency, generation and transmission facilities shall be used to the fullest extent practicable to promptly restore normal system frequency and voltage and return ACE to acceptable performance criteria as defined in Policy 1E.

1.1. **Schedule assistance.** The deficient system shall schedule all available assistance that is required with as much advance notice as possible.

1.2. **Using Interconnection's bias.** The deficient system shall use the assistance provided by the Interconnection's frequency bias only for the time needed to accomplish the following:

1.2.1. **Operating reserve.** Utilize its readily available operating reserve.

1.2.2. **Own resources.** Analyze its ability to recover using only its own resources.

1.2.3. **Assistance from others.** If necessary, determine the availability of assistance from other systems and schedule that assistance.

2. **Emergency action.** If all other steps prove inadequate to relieve the capacity emergency, the system shall take immediate action which includes, but is not limited to, the following:

2.1. **Schedule all available emergency assistance from other systems.**

2.2. **Implement manual load shedding**.

3. **Unilateral action.** Unilateral adjustment of generation to return frequency to normal by systems not experiencing capacity deficiencies, beyond that supplied through frequency bias action and interchange schedule changes, shall not be attempted. Such adjustment may jeopardize overloaded transmission facilities.

Guides

1. **Notification of emergency.** If a capacity or energy emergency is foreseen, contact neighboring systems as far in advance as possible to assess regional conditions and arrange for whatever relief is available or required.

2. **Notifying other systems.** Control areas should continue to apprise the interconnected systems of the level of generating capacity or energy supply and future needs.

3. **Voltage reduction on distribution system.** Voltage reduction for load relief should be made on the distribution system. Voltage reduction on the subtransmission or transmission system may be effective in reducing load; however, voltage reduction should not be made on the transmission system unless the system has been isolated from the Interconnection.

C. Transmission Overload

Effective until December 31, 1996

Criteria

When line loadings, equipment loadings, or voltage levels deviate from normal operating limits or can be expected to exceed emergency limits following a contingency, and reliability of the Interconnection is threatened, those control areas experiencing and those control areas contributing to the condition shall take immediate steps to relieve the condition. These steps include notifying other systems, adjusting generation, changing schedules between control areas, initiating line and equipment load relief measures, and taking such other action as may be required.

Requirements

1. **Dealing with transmission contingencies.** Each NERC Region shall ensure that policies and procedures are developed and specified for dealing with transmission contingencies that threaten the reliability of the Interconnection, coordinating equipment ratings and outages, coordinating switching, monitoring and controlling voltage levels and MW and MVAr flows, and implementing line and equipment loading relief procedures.

2. **Procedures.** Where specific transmission reliability issues have been identified, those systems affected by and those systems contributing to the problem shall develop joint procedures for maintaining transmission reliability.

3. **Overloads caused by other system.** If an overload on a transmission facility or abnormal voltage/reactive condition persists due to operations of another system, the affected system shall notify the neighboring or remote system(s) of the severity of the overload or abnormal voltage/reactive conditions and request appropriate relief.

4. **Disconnection of overloaded equipment.** If the overload on a transmission facility or abnormal voltage/reactive condition persists and equipment is endangered, the affected system or pool may disconnect the affected facility. Neighboring systems impacted by the disconnection shall be notified prior to switching, if practicable, otherwise, promptly thereafter.

5. **Action shall not reduce reliability.** Action to correct a transmission overload shall not impose unacceptable stress on internal generation or transmission equipment, reduce system reliability beyond acceptable limits, or unduly impose voltage or reactive burdens on neighboring systems. If all other means fail, corrective action may require load reduction.

6. **Action to keep transmission within limits.** Systems shall take all appropriate action up to and including shedding of firm load in order to keep the transmission facilities within acceptable operating limits, prevent imminent separation from the Interconnection, or to prevent voltage collapse.

Guides

1. **Data for loading relief.** On-line, real-time values should be used as much as possible in the implementation of line and equipment loading relief procedures.

C. Transmission System Relief

Effective beginning January 1, 1997

Introduction

This policy:

1. Summarizes the authority, information and tools required by SYSTEM OPERATORS responsible for the security of the INTERCONNECTIONS.

2. Identifies the accountability for developing and implementing procedures to alleviate OPERATING SECURITY LIMIT violations.

3. Describes the requirement to develop procedures for the curtailment and restoration of transmission service.

Requirements

2. **Relieving security limit violations.** Each CONTROL AREA experiencing or materially contributing to an OPERATING SECURITY LIMIT violation shall take immediate steps to relieve the condition.

3. **Operator authority and responsibility.** SYSTEM OPERATORS having responsibility for the security of the transmission system within a CONTROL AREA, pool, etc. shall be given and shall exercise specific authority to alleviate OPERATING SECURITY LIMIT violations. The authority shall enable the SYSTEM OPERATOR to take timely and appropriate actions including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding load, etc.

   3.1. **Action shall not reduce reliability.** Action to correct an OPERATING SECURITY LIMIT violation shall not impose unacceptable stress on internal generation or transmission equipment, reduce system reliability beyond acceptable limits, or unduly impose voltage or reactive burdens on neighboring systems. If all other means fail, corrective action may require load reduction.

   3.2. **Disconnection of overloaded equipment.** If the overload on a transmission facility or abnormal voltage/reactive condition persists and equipment is endangered, the affected system or pool may disconnect the affected facility. Neighboring systems impacted by the disconnection shall be notified prior to switching, if practicable, otherwise, promptly thereafter.

4. **Security violation assessment.** Sufficient information and analysis tools shall be provided to the SYSTEM OPERATOR to determine the cause(s) of OPERATING SECURITY LIMIT violations. This information shall be provided in both real time and predictive formats so that the appropriate corrective actions may be taken. **Effective Jan. 1, 1998**

5. **Transmission service and energy schedule prioritization.** Each CONTROL AREA shall develop prioritization procedures for the curtailment of transmission service and energy schedules.

5.1. **Effectiveness.** These procedures shall provide for the curtailment of only those energy and transmission service schedules that effectively alleviate the OPERATING SECURITY VIOLATION will be interrupted.

5.2. **Coordination.** These procedures shall be coordinated with adjacent control areas in accordance with the REGIONAL SECURITY PLAN.

5.3. **Curtailment and restoration sequence.** The curtailment and restoration sequence shall be consistent with the approved tariffs and regulatory requirements of the transmission service provider(s).

Guides

1. If the SYSTEM OPERATOR can project a curtailment requirement adequately, the transmission service customer should be notified. However, if time is not available, the SYSTEM OPERATOR will take whatever actions are necessary as specified in Policy 5C, Requirement 2.

D. Separation from the Interconnection

Criteria

Because the facilities of each system may be vital to the secure operation of the Interconnection, systems and control areas shall make every effort to remain connected to the Interconnection. However, if a system or control area determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect its system.

If a portion of the interconnection becomes separated from the remainder of the interconnection, abnormal frequency and voltage deviations may occur. To permit resynchronizing, relief measures shall be applied by those separated systems contributing to the frequency and voltage deviations.

Guides

1. **Load shedding to prevent separation.** In those situations where it will be beneficial, manual load shedding should be used to prevent imminent separation from the Interconnection due to transmission overloads or to prevent voltage collapse.

2. **Generator shutdown.** If abnormal levels of frequency or voltage resulting from an area disturbance make it unsafe to operate the generators or their support equipment in parallel with the system, their separation or shutdown should be accomplished in a manner to minimize the time required to re-parallel and restore the system to normal.

   2.1. **Separating generators with local load.** If feasible, generators should be separated with some local, isolated load still connected. Otherwise, generators should be separated carrying their own auxiliaries. *First sentence is a duplicate of Guide 2 above.*

3. **AGC.** AGC should remain operative if practicable.

4. **Instructions for plant operators.** Plant operators should be supplied with instructions specifying the frequency and voltage below which it is undesirable to continue to operate generators connected to the system.
5. **Generator protection at high and low frequency.** Protection systems should be considered for automatically separating the generators from the system at predetermined high and low frequencies.

E. System Restoration

[Policy 6D — Operations Planning–System Restoration]
[System Restoration and Blackstart Procedures Reference Document]

Criteria

After a system collapse, restoration shall begin when it can proceed in an orderly and secure manner. Systems and control areas shall coordinate their restoration actions. Restoration priority shall be given to the station supply of power plants and the transmission system. Even though the restoration is to be expeditious, system operators shall avoid premature action to prevent a re-collapse of the system.

Customer load shall be restored as generation and transmission equipment becomes available, recognizing that load and generation must remain in balance at normal frequency as the system is restored.

Requirements

1. **Returning to normal operations.** Following a disturbance in which one or more system areas become isolated, steps shall begin immediately to return the system to normal:

    1.1. **Extent of isolated system.** The system operator shall determine the extent and condition of the isolated area(s).

    1.2. **Frequency restoration.** The system operator shall then take the necessary action to restore system frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.

    1.3. **Interchange schedule review.** Interchange schedules between control areas or fragments of control areas within the separated area shall be immediately reviewed and appropriate adjustments made in order to gain maximum assistance in restoration. Attempts shall be made to maintain the adjusted schedules whether generation control is manual or automatic.

    1.4. **Resynchronizing.** When voltage, frequency and phase angle permit, the system operator may resynchronize the isolated area(s) with the surrounding area(s), properly notifying adjacent systems, and considering the size of the area being reconnected and the capacity of the transmission lines effecting the reconnection.

    1.5. **Off-site supply for nuclear plants.** Restoration of off-site power to nuclear stations shall be given high priority.

Guides

1. **Isolating loads to help restoration.** In order to systematically restore loads without overloading the remaining system, opening circuit breakers should be considered to isolate loads in blacked-out areas.

2. **Restoration.** Load shed during a disturbance should be restored only when doing so will not have an adverse effect on the system or Interconnection.

   2.1. **Manual restoration.** Load may be restored manually or by supervisory control only by direct action or order of the system operator as generating and transmission capacity become available.

   2.2. **Automatic restoration.** Automatic load restoration may be used where feasible to minimize restoration time.

      2.2.1. **Coordination.** Automatic restoration should be coordinated with neighboring systems, coordinated areas, and Regions.

      2.2.2. **Must not burden others.** Automatic restoration should not aggravate system frequency excursions, overload tie lines, or burden any system in the Interconnection.

3. **Oil-filled cables.** Reenergizing oil-filled pipe-type cables should be given special consideration, especially if loss of oil pumps could cause gas pockets to form in pipes or potheads.

4. **Maintaining transmission voltage.** The following should be considered when trying to maintain normal transmission voltage during restoration:

   4.1. **Preventing excessive voltage.** Removal of shunt capacitors or addition of reactors or addition of small blocks of isolated load to prevent excessive voltage when energizing long transmission lines.

   4.2. **Energizing cables.** Effects of energizing high-voltage cables at the end of a long, lightly-loaded system.

   4.3. **Reactive considerations.** The capability of the generators to provide or absorb reactive power flows.

F. Disturbance Reporting

[Appendix 5F — Reporting Requirements for Major Electric Utility System Emergencies]

Criteria

Disturbances or unusual occurrences which jeopardize the operation of the interconnected systems, that result, or could result, in system equipment damage, or customer interruptions, shall be studied in sufficient depth to increase industry knowledge of electrical interconnection mechanics so that similar events can be

prevented. The facts surrounding a disturbance shall be made available to system and control area operators, system managers, Reliability Councils, and regulatory agencies entitled to the information.

Requirements

1. **Analyzing disturbances.** Bulk system disturbances affecting two or more systems shall be promptly analyzed by the affected systems.

2. **Disturbance reports.** Based on the magnitude and duration of the disturbance or unusual occurrence, those systems responsible for investigating the incident shall provide oral, and if appropriate, written reports.

   2.1. **Oral report.** An oral report shall be made to the systems' Regional Council staff within twenty-four hours after the disturbance. This oral report is in addition to the reporting requirements of any regulatory agency having jurisdiction over the systems.

3. **Notifying DOE.** The U.S. Department of Energy's most recent Power System Emergency Reporting Procedures, shown in **Appendix 5F** are the minimum requirements for reporting disturbances to NERC.

Guides

1. **Reporting operating problems.** If an operating problem cannot be corrected quickly, the probable duration and possible effects should be reported.

2. **Written reports.** The system should provide written reports following a disturbance.

   2.1. **Report timing.** If appropriate, a preliminary written report should be available within several days of the disturbance.

   2.2. **Report review.** If appropriate, a final written report should be available for review according to system policies.

3. **Reporting "unusual occurrences."** If, in the judgment of the system(s) involved, such an "unusual occurrence" would be of interest to the electric utility industry, the incident should be reported to NERC whether or not it is reported under DOE Reporting Procedures.

4. **Assistance from NERC OC.** When there has been a disturbance affecting the bulk system, the Region's OC representatives should make themselves available to the system or systems immediately affected in order to provide any needed assistance in the investigation.

5. **Reports from other systems.** Information concerning bulk system disturbances in other parts of the world can be of value in furthering the objectives of NERC. To the extent that relevant information can be obtained, it should be appropriately utilized.

G. Sabotage Reporting

Criteria

Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.

Requirements

1. **Recognizing sabotage.** Each control area shall have procedures for the recognition of and for making its system operators aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection. Procedures shall also be established for the communication of information concerning sabotage events to appropriate parties in the Interconnection.

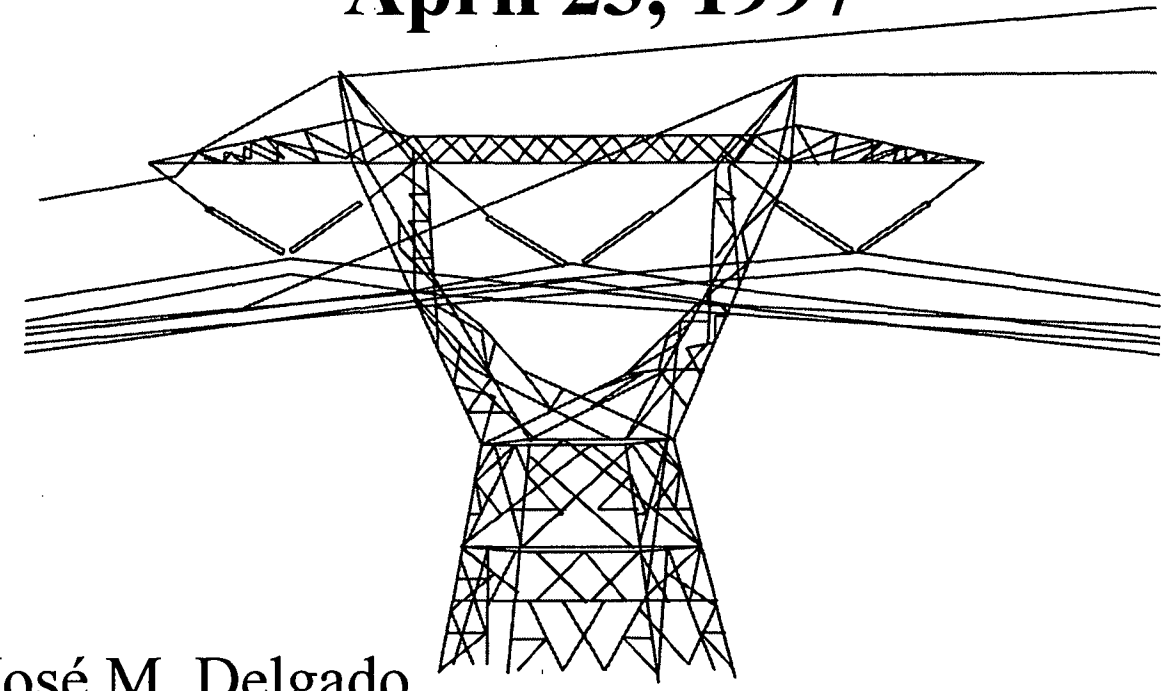
2. **Reporting guidelines.** System operators shall be provided with guidelines including lists of utility contact personnel, for reporting disturbances due to sabotage events.

3. **Contact with FBI and RCMP.** Systems shall establish communications contacts with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.

Guides

1. **Information to media.** Systems should establish procedures for supplying sabotage-related information to the media. Release of this information must be coordinated with the appropriate FBI or RCMP personnel.

Nuclear Regulatory Commission Briefing on Electric Grid Reliability April 23, 1997



José M. Delgado
Director, Electric System Operations
Wisconsin Electric Power Company

Deregulation Will Not Impair Transmission Security

- Maintaining Reliability Is One Of The Few Areas Of Solid Consensus In The Industry
- Security & Adequacy Are the Two Basic Aspects Of Grid Reliability
- The Transmission Network Can Be Secure Even If Not Adequate but It Cannot Be Adequate Without Security
- Transmission Operators Will Assure System Security
- Market Participants Will Assure Adequacy
- Regional Transmission Planning will Improve Long Run Adequacy and Security by Removing Constraints

Grid Reliability Will Be Enhanced By Regional Operation And Planning

- ISOs Being Developed in the Midwest:
  - Will Have Real Time Information Over Broad Areas of the Network
  - Will Have Authority Over All Transmission Operations Including the Redispatch Generation to Assure Network Security
  - Will Produce a Regional Transmission Plan
    - Regional Planning Will Enhance Local Planning
  - Will Operate Within Rules Set By Regional Reliability Councils and Regulatory Entities
    - Special Requirements and Priorities of Generating Plants (e.g. Nuclear Plants Requirements) Will Be Identified by Plant Owners/Operators and Maintained by the ISO
- Transmission Owners Will Retain Responsibility Over Local System Conditions and Over the Maintenance, and Hands-On Operation Of Transmission Equipment, Under the Authority of the ISO

System Operations In Wisconsin

- System Operators Have Wide Variety Of Background and Experience, Including Fossil And Nuclear Plant O&M
- Operator Training
  - On the Job Training - Use of Procedures & Simulators
  - Joint Training Through WUMS System Operator Training
  - Control Room Certification by MAIN Has Been Completed
  - Future NERC Operator Certification
- Energy Management Systems (EMS) Monitor Special Reliability Requirements
  - Nuclear Plant Requirements and Procedures Are Built Into the EMS Displays

Western Systems Coordinating Council

Briefing on Electric Grid Reliability

Comments by the Western Systems Coordinating Council

Before the Nuclear Regulatory Commission
April 23, 1997

By Mr. Dennis E. Eyre
Executive Director, Western Systems Coordinating Council

Thank you, it is a distinct honor to appear before you today to discuss restructuring and electric system reliability.

I am Dennis Eyre, executive director of the Western Systems Coordinating Council (WSCC).

Overview of WSCC

WSCC is the largest and most diverse of the 10 regional reliability councils of the North American Electric Reliability Council (NERC). WSCC's service territory extends from Canada to Mexico, an area of nearly 1.8 million square miles. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. The interconnected transmission system within the WSCC region is known as the Western Interconnection. It is one of the four major electric grids in NERC.

WSCC has 99 members ranging from 71 traditional utilities to 10 independent power producers to 18 marketers. Three state regulatory representatives serve on WSCC's Board of Trustees.

Who is Responsible for Reliability?

As industry restructuring occurs and we implement competition, it is imperative that each of us continue to do our part to maintain electric system reliability. For over 30 years, NERC and the regional councils have been the caretakers of reliability through the cooperative development of NERC and regional council policies, procedures, and criteria. There is no reason to doubt the ability, appropriateness, and the resolve of NERC and the regional councils to continue to serve as "self-regulating organizations" responsible for establishing and monitoring compliance with the required reliability standards and for administering the appropriate incentive, sanction, and financial penalty programs. WSCC and NERC are committed to enhancing accountability for reliability and improving compliance with reliability standards. WSCC strongly favors an industry "self-regulating organization" approach with a federal and/or state regulatory backstop as may be appropriate.

Actions Being Taken by WSCC to Ensure Reliability

WSCC is continually and expeditiously implementing new protocols and mechanisms to ensure reliability is not sacrificed as we restructure the industry.

In 1996, the WSCC Board of Trustees unanimously endorsed a reliability compact that reaffirms the Council's mandatory compliance requirements and which will result in the enforcement of established reliability protocols in the West. The compact recognizes that to ensure continued reliability, all market participants must adhere to the established reliability protocols. A policy level group has been formed to develop incentives and sanctions for

implementing the reliability compact. These recommendations will be submitted to the WSCC membership by the end of 1997.

The WSCC agreement states that all control areas, which includes independent system operators (ISOs), must be members of WSCC, and as such, they must comply with all WSCC and NERC protocols and sanctions. Also, and of importance to you, the most recent California ISO filing includes a Transmission Control Agreement, which requires the ISO to meet the WSCC and NERC protocols and the provisions of the NRC Plant Licenses. In addition, NERC's Operating Manual Policy 5 - Emergency Operations presently calls for system operators to give a "high priority" to nuclear plant restoration. I believe, however, that we need to further clarify this policy to make sure this issue is properly addressed; and therefore, I will be recommending that the NERC and WSCC criteria be reviewed and revised as necessary to meet nuclear plant requirements.

Mandatory compliance does not stop with WSCC. NERC also made compliance with its protocols mandatory. By establishing a system of mandatory compliance, all market participants will be accountable for adhering to established protocols and will result in a level playing field.

Another reliability program WSCC has established is the compliance monitoring program, which reviews members' compliance with the WSCC Minimum Operating Reliability Criteria; WSCC operating policies, procedures, and guidelines; and NERC Operating Policies for Interconnected Systems Operation.

In addition, WSCC and NERC are in the process of enhancing their operating protocols to make them as specific and measurable as possible. WSCC, and the other regional councils, are implementing additional security measures. These measures will enhance interconnected system reliability through the exchange of information required to assess system security and reliability, including on-line power flow and security analysis and increased system monitoring. These measures will enhance the operators' ability to identify potential reliability problems and promptly take proactive corrective actions to ensure system security.

The Council has approved a Regional Security Plan that is intended to convey both the responsibility for overall system reliability and the authority needed to carry out that responsibility successfully. This plan was developed and is currently being implemented in response to one of the four Strategic Initiatives for Reliability established by NERC. The Regional Security Plan empowers the security coordinating centers to take the actions necessary to preserve reliability. The California ISO will be one of the security coordinating centers, and it is envisioned that the other ISOs being formed in the west will also become security coordinating centers.

WSCC also has an established and successful training program that has been carefully structured to provide system dispatchers and other operating personnel with the necessary skills to deal with the ever-increasing complexity of interconnected system operation and to ensure interconnected electric system reliability. In addition, a new Schedulers/Contract Writers Training Program was implemented in 1996. This training program familiarizes schedulers, contract writers, and energy accountants with system operations and increases their understanding of how their actions impact interconnected

system operation and reliability. Although WSCC currently has an operation training program, we are also working with NERC to implement a certification program.

Is the Transmission System Being Used Differently than Originally Designed and Will It Impact Reliability?

This question has been posed by the public, the regulatory community, and members of industry. As long as established operating protocols and those being implemented by the industry are followed, transmission reliability will be maintained. Industry and the regional reliability councils recognize the changing, competitive nature of the industry and the impact this may have on system operations. As such and as we speak, new protocols are being developed to address the changes occurring and being forecast for electric system operation.

Implementation Issues to Consider

As the electric industry becomes more competitive, we must make certain that interconnected system reliability is preserved. As time frames are established for restructuring this industry, we must all bear in mind that these time frames must be realistic and prudent, and that they may have to be revised to maintain reliability.

The regulatory community, especially the Federal Energy Regulatory Commission (FERC) and the state regulatory agencies, will need to serve in a backstop role, providing NERC and the regional councils with the required tools to maintain and ensure reliability. The regulatory community should then hold NERC and the regional councils accountable for ensuring reliability is maintained.

We must ensure that all entities that own, operate, or use the interconnected transmission system are complying with the established criteria, guidelines, policies, and procedures of WSCC and NERC. To ensure compliance, NERC and the regional councils must be able to monitor those involved and correct those in noncompliance. Where financial or business incentives cannot be developed to ensure compliance and accountability, the regional reliability councils, working with the ISOs and others, must have the ability to impose sanctions or fines on noncomplying members, so that one participant's noncompliance does not degrade reliability or increase costs for other market participants.

Federal or state action mandating membership in the reliability councils and NERC or some other federal or state mechanism will almost certainly be needed to equitably administer the costs of maintaining reliability and ensure compliance with the "rules of the road" that have been established to preserve reliability.

Conclusions

Restructuring will impact the electric industry ... that impact can be positive if all of us involved in the restructuring process do it right the first time. Commercial pressures may stress the reliability of the electric system. Consequently, we will need to ensure that the balance between competition and reliability is maintained. We need to move through restructuring in a prudent and timely manner. However, we must manage this transition with a critical eye if we are to ensure that any complications that develop will not impact our objective of preserving reliability. The ISOs being formed in the West will have a responsibility to maintain system reliability, and as members of WSCC, will play an essential role in administering interconnected system reliability. NERC and the regional reliability councils, as self-regulating organizations having the support of the regulatory community, must have the appropriate tools, and therefore the ability to continue to effectively manage electric system reliability. No matter how dramatically the industry changes and evolves, the public will expect and demand reliable service. Mandatory compliance, reliability monitoring, enforcement capability, and accountability will be essential for ensuring the public's desired level of reliability.

This concludes my comments. I would be pleased to address any questions you may have.

Electric Grid Reliability

Office for Analysis and Evaluation of Operational Data
Office of Nuclear Reactor Regulation

April 23, 1997

OVERVIEW

- Electric grid reliability can affect the safe operation of nuclear power plants.
- AEOD performed an electric grid study because of several grid events.
- The study identified various grid performance factors.
- Recommendation from this study is for licensees to confirm and maintain licensing basis.
- NRR will discuss original licensing basis and actions being considered to address the grid reliability issue.

SAFETY ISSUE

- Reliable power needed for safety equipment.
- Severe Accident Study, NUREG-1150, determined station blackout a major contributor to core damage frequency.
- IPE Insights, Draft NUREG-1560, determined station blackout continues to be a significant factor for some plants.
- Offsite power is the preferred source.
- Adequate safety based on combination of both offsite and onsite power.
- Changes in the industry could affect future reliability of electrical grid.

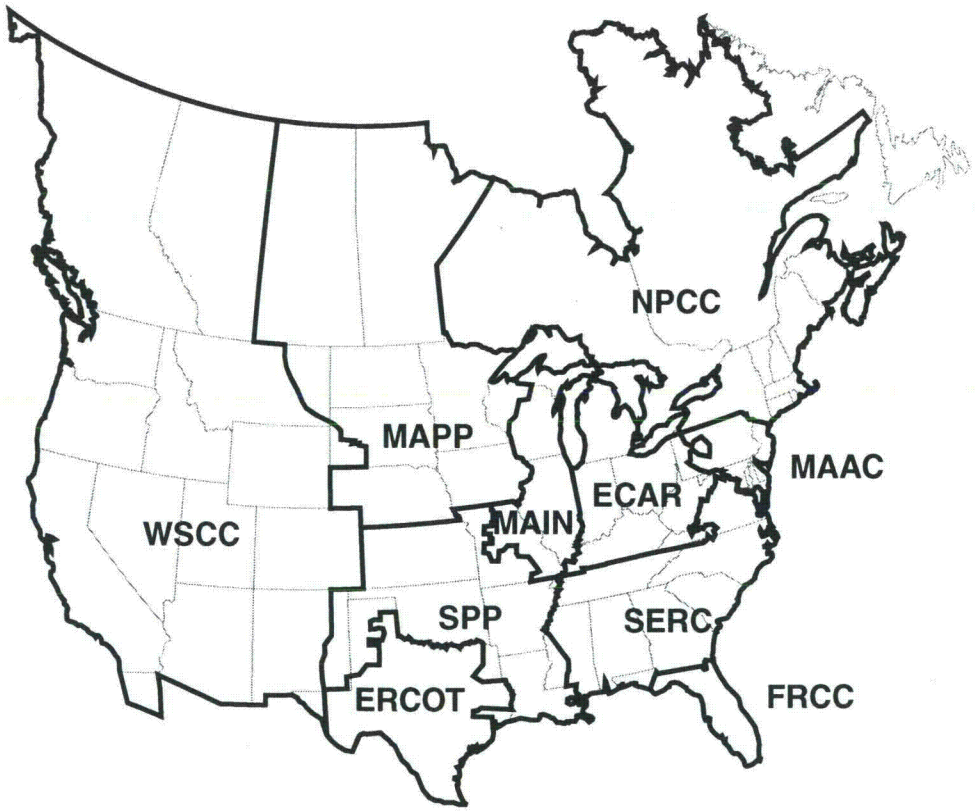
Grid Performance Factors

April 23, 1997

Mary S. Wegner

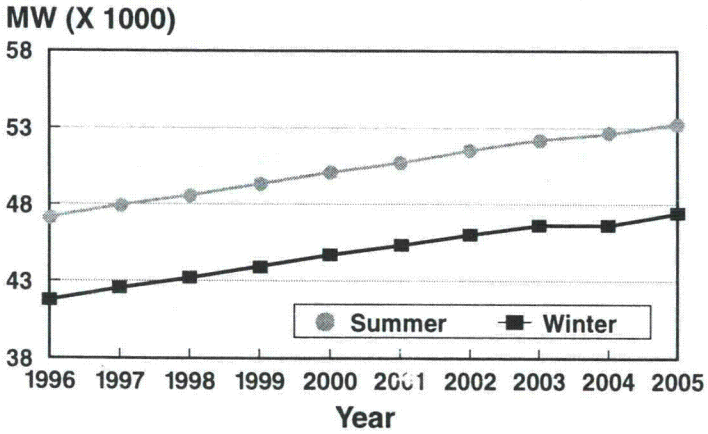
NORTH AMERICAN ELECTRIC RELIABILITY COUNCILS

Figure supplied by the North American Electric Reliability Council

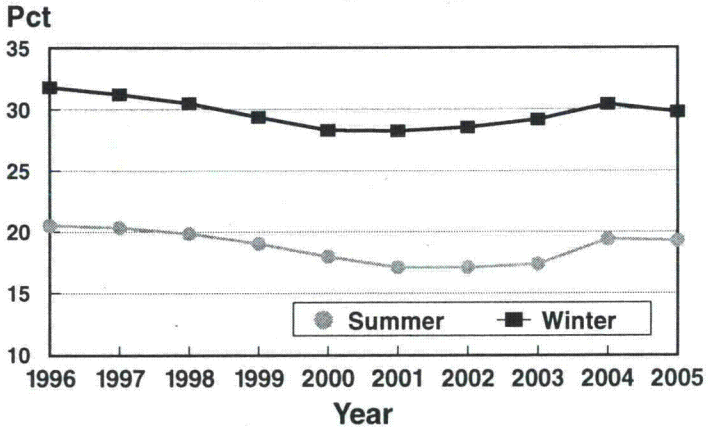


Mid-Atlantic Area Council

Peak Demand for 10 Years

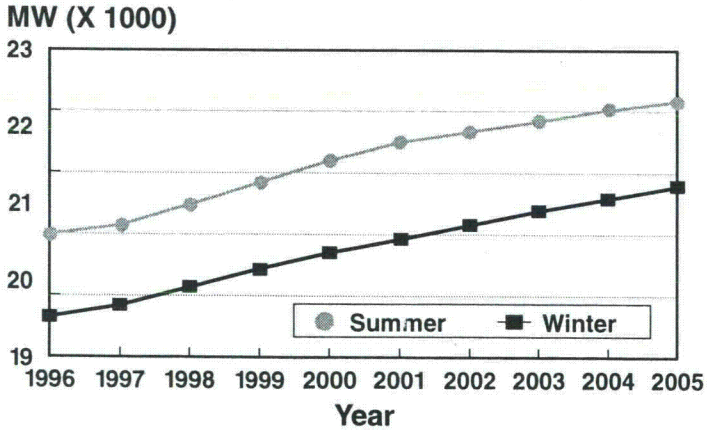


Capacity Margin

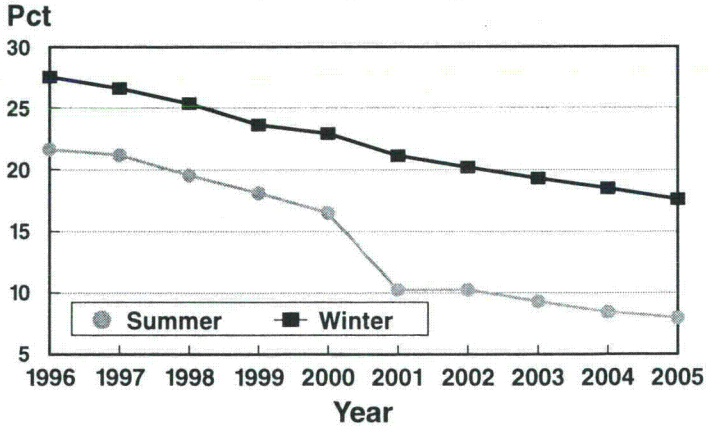


Northeast Power Coordinating Council – New England

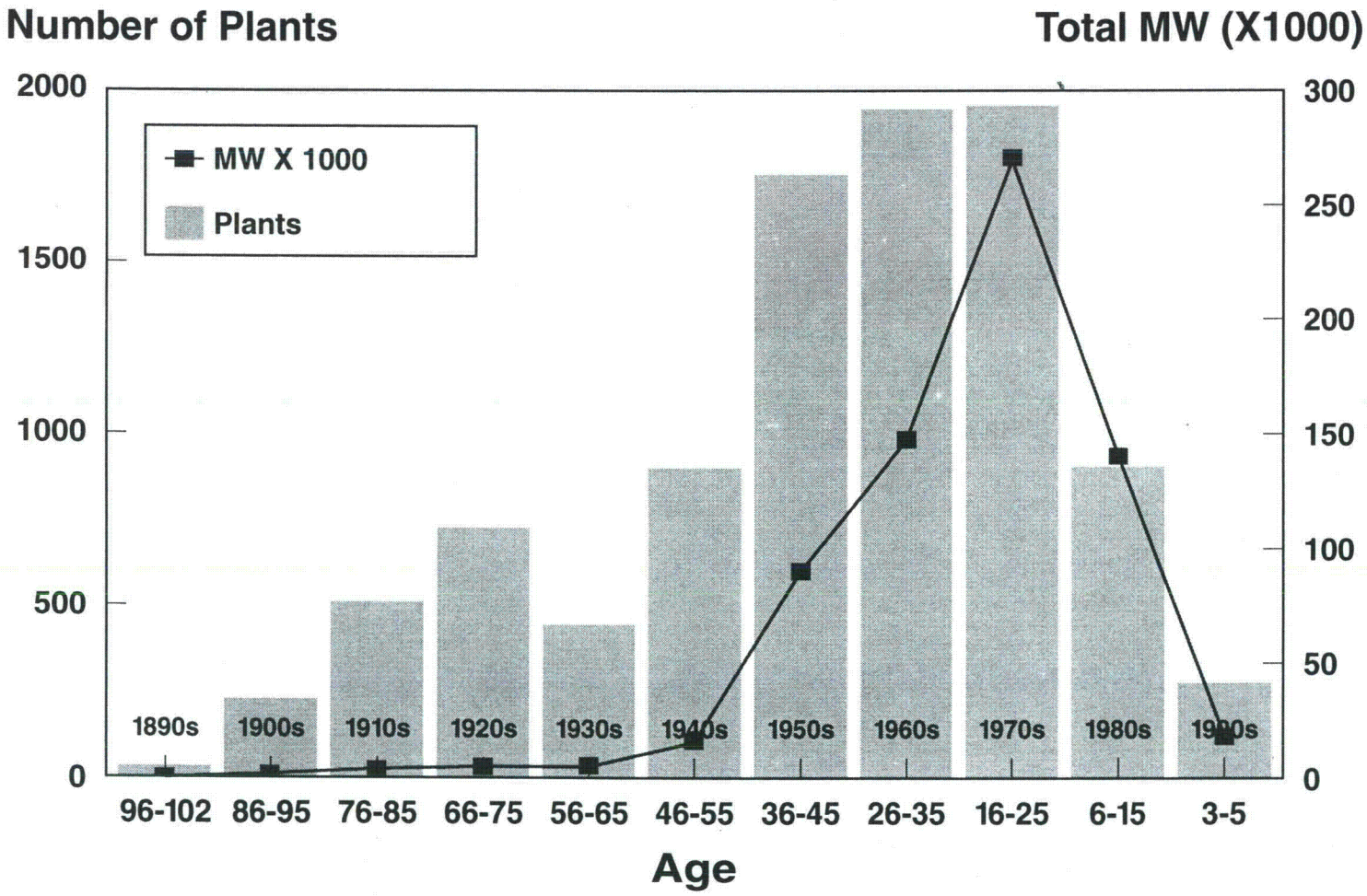
Peak Demand for 10 Years



Capacity Margin



PLANT AGE


Number of Plants
Total MW (X1000)
2000
1500
1000
500
0
300
250
200
150
100
50
0
MW X 1000
Plants
1890s
1900s
1910s
1920s
1930s
1940s
1950s
1960s
1970s
1980s
1990s
96-102
86-95
76-85
66-75
56-65
46-55
36-45
26-35
16-25
6-15
3-5
Age

OPERATING EVENTS

- **Excessive Demand**

  The Mid-Atlantic Cold Spell of 1994

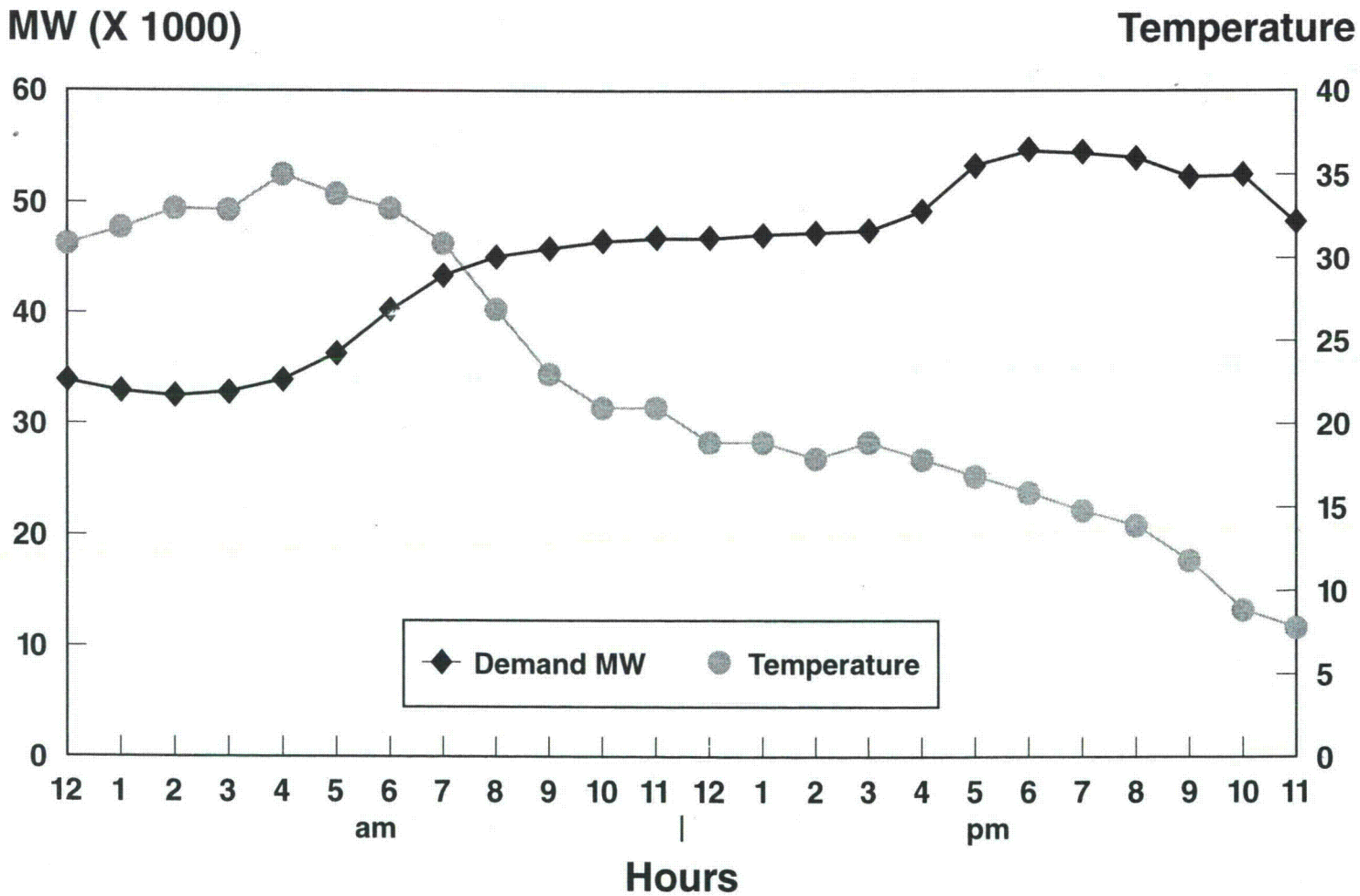
- **Fault**

  Virgil Summer Event of 1989
  Western Grid Disturbance of August 10, 1996

- **Potential Instabilities Found by Analysis**

TEMPERATURE EFFECTS ON LOAD

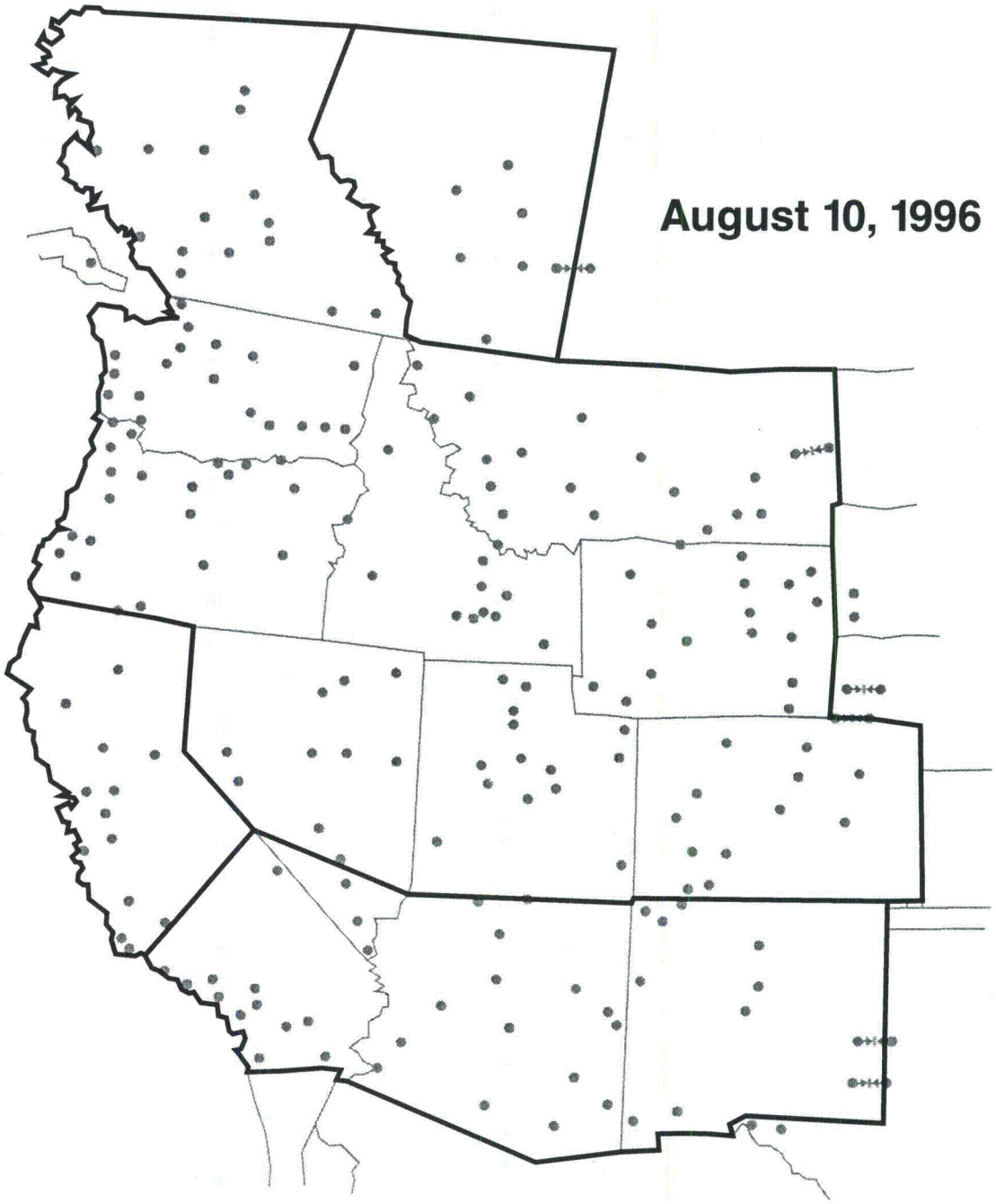
Cold Spell of 1994 Mid-Atlantic Area



MID-ATLANTIC AREA COUNCIL LOAD REDUCTION MEASURES

1. Curtailment of non essential power company station light and power
2. Reduction of controllable interruptible/reducible loads
3. Voltage reductions
4. Reduction of nonessential load in power company buildings
5. Voluntary customer load reduction
6. Radio and television load reduction appeal
7. Manual load shedding
8. Automatic actuation of underfrequency relays which shed 10% of load at 59.3 Hz, 10% at 58.9 Hz, and 10% at 58.5 Hz

WESTERN GRID DISTURBANCE



CONCLUSIONS

- On the whole, the grid is stable and reliable
- Problems described in the Regional Reliability Council assessments as well as uncertainties introduced by restructuring of the electric industry indicate the need to monitor grid on a regular basis

AEOD RECOMMENDATION

- NRR request licensees to confirm that they continue to meet their licensing bases with respect to the stability and reliability of offsite electric power.

- Licensees should further be requested to maintain a process for ensuring they continue to meet their licensing bases in this area for the remainder of their license.

LICENSING BASIS

- GDC-17 REQUIREMENTS
  - An onsite power system and offsite power system shall be provided, each independent of the other and capable of providing power for all safety functions.
  - Onsite electric power supplies must meet single failure criterion and provide power for the minimum required safety functions.
  - The offsite power system shall consist of two physically independent circuits connecting the grid to the safety buses. Each of the two offsite power circuits shall be available in sufficient time to shut the reactor down.
  - Provisions shall be included to minimize the loss of offsite power.
- GRID STABILITY CONSIDERATION
  - Analyses must verify that the grid remains stable in event of:
    - Loss of the nuclear unit generator
    - Loss of the largest other unit on the grid
    - Loss of the most critical transmission line

NRR ACTIONS - GRID RELIABILITY

- Continue to monitor industry deregulation developments and its impact on offsite power to nuclear power plants.
  - Staff has met with Connecticut Valley Exchange, ComEd, NERC, NEPOOL, DOE, and FERC in order to gain insights regarding future changes in the industry.
- Assess the risk significance of potential grid instability due to deregulation.
  - Utilize contractor expertise (Target Completion Date: 9/98).
- As recommended by AEOD, we plan to issue generic communications which will reemphasize the need for licensees to maintain their design basis with respect to the stability and reliability of offsite power, and to maintain a process for ensuring that they continue to meet their design basis for the remainder of their license (Target Completion Date: 10/97).
- Plan to reassess the risks from SBO (Target Completion Date: 12/98).