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BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

- - - - -x
IN THE MATTER OF: : Docket Number
CAPACITY MARKETS IN THE : PL05-7-000
PJM REGION :
- - - - -x

Hearing Room 2C
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C.

Thursday, June 16, 2005

The above-entitled matter came on for technical
conference, pursuant to notice, at 9:05 a.m.

PRESIDING:
ANNA COCHRANE
FERC STAFF

18895
DAV

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

2 (9:05 a.m.)

3 MS. COCHRANE: Good morning. Welcome to the
4 Federal Energy Regulatory Commission Technical Conference on
5 Capacity Markets in the PJM Region.

6 I'm Anna Cochrane, Director of the Division of
7 Tariffs and Market Development-East. I have a number of
8 Staff people with me: Derrick Bandera with Chairman Pat
9 Wood's Office; Dick O'Neill, the Commission's Chief
10 Economist; Dave Kathen, also with OMTR-East; Morris
11 Margolis, with OMTR-East; David Mead with the OMTR Policy
12 Division, and Sebastian Tiger and Harry Singh, with the
13 Office of Markets, Oversight and Investigations, and
14 Katherine Waldbauer with the Office of General Counsel will
15 be joining us.

16 I'd also like to recognize Sarah McKinley, who
17 has been instrumental in organizing this event, and has made
18 sure that we all have name tags, microphones, and all kinds
19 of things set up for us. Thank you, Sarah.

20 On May 19, the Commission issued an Notice
21 announcing this Technical Conference, and, on June 8th, the
22 Commission issued a Supplemental Notice of the Conference,
23 setting forth the agenda and panelists.

24 As stated in the Notices, this Conference is
25 intended to provide a forum for members and Staff of the
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18895

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1 FERC and of state public utility commissions, so they may
2 come to a common understanding of the current PJM capacity
3 situation, the problems perceived in the market, and what
4 deficiencies, if any, exist in the current market construct
5 that contribute to or do not properly address those
6 perceived problems, and to talk about potential alternative
7 solutions.

8 We're especially fortunate that Commissioner
9 Brownell is here with us today, and has taken an active
10 interest in this proceeding. Would you like to say a few
11 words?

12 COMMISSIONER BROWNELL: Thank you very much. I'd
13 like to thank everybody who got up this morning to talk
14 about this exciting topic.

15 I would particularly like to thank my fellow
16 commissioners from the states, who have taken an
17 extraordinary role in asking for a dialogue in trying to get
18 to solutions. So we welcome them and encourage them to
19 participate. AS we do, you'll see some of the state staff
20 sitting behind our staff.

21 I want to talk just a little bit about why we
22 have technical conferences, because when we suggested this,
23 it was amazing for the hundreds and hundreds of technical
24 conferences that we've had, this one assumed kind of some
25 emotional overtones in the same way that this proposal has.

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Why are we doing this? Is this to rubber-stamp?

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Is this to force solutions? Is this to do a variety of

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things?

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So I want to be very clear from the outset that

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this is to have an open discussion of what has been proposed

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and what some of the interrelationships are to other issues,

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to make sure that we're working with a common set of

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definitions.

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It's extraordinary to me, the number of times we

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have very technical conversations and everybody's talking

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about something different. So, let's just, at the very

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least, make sure we're talking about the same things, and

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then to get out where we can find consensus and where we

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cannot.

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We don't expect, in something that involves huge

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amounts of money, to get 100-percent consensus. That's why

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we get paid the big bucks.

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But I think it is important to be as creative as

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we possibly can, in coming up with ideas, either the one

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that's on the table or alternatives or different pieces, to

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see if we can bring some value to the customers.

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I don't think there's anyone in the world who

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thinks that capacity markets, as they exist today, are

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sending the appropriate economic signals. We can also

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18895

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1 debate that, in a perfect world, we might not need capacity
2 markets, but we are not in a perfect world.

3 We are not in a perfect market; we are not
4 anywhere close to a perfect market. So, a couple of things
5 I would just ask you to do: I would ask you to listen.
6 Everyone comes with their own set of brilliant ideas. We
7 have got the old PowerPoints, we read them, we declare
8 victory and we go home.

9 The only way we will solve the problem, is if we
10 listen to each other and respect each other's ideas. There
11 are a lot of smart people in the room, and not everybody
12 approaches things in the same way.

13 So, I think that's the most critical lesson. The
14 other thing, just for our own sanity, we have a long day,
15 and if it's been said 15 times before, just sing the
16 Hallelujah Chorus and say I agree; you don't have to say it
17 again.

18 If it has been disagreed with 17 times before, do
19 not give us the 14 reasons you disagree; simply say can't
20 get there, can't support it; it's over.

21 That will leave us time for a back-and-forth, a
22 dialogue, a meaningful discussion of the issues at hand.
23 So, it's a great opportunity, I think, to show that we can
24 work together to come to common solutions, or it's a very,
25 very, very long, painful day, and it's been a long week, and

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18895

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1 I don't have time for a long, painful day, and neither do my
2 colleagues.

3 So, with that, Anna, I'm going to hand it over to
4 you, and I encourage a lot of participation by my fellow
5 Commissioners, and not only by our Staff, who don't need to
6 encouraged to participate, but the state staffs as well.
7 Thank you.

8 MS. COCHRANE: Thank you, Nora. The first panel
9 is entitled General Capacity Market Objectives and PJM.

10 As Commissioner Brownell just stated, part of
11 this is to get us on the same page and have consistent ideas
12 about where PJM currently is, what the objectives of the
13 capacity market are, how it relates with other markets, and
14 does PJM's current capacity construct meet those objectives?

15 Our first panelist is Mr. Joe Bowring, Manager of
16 the PJM Market Monitoring Unit.

17 MR. BOWRING: Thank you. It's an honor and a
18 pleasure to be here to start off. I would just note that
19 there are hard copies or will be soon, hopefully, hard
20 copies of my document in the back. There was a printing
21 issue this morning, which is why I have my computer up in
22 front of me.

23 The first question I'd like to address is: Why
24 capacity markets? I think, very simply, the equilibrium
25 level of resources, energy resources, is higher when there's
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18895
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1 a determined level of reliability, when there's a required
2 level of reliability.

3 In an energy-only market, without a determination
4 of the required level of reliability, reliability will be
5 determined by the market; it will be endogenous and will be
6 at a lower level than with the capacity market.

7 The result of those additional resources will be
8 an equilibrium, again, a lower price; fewer high prices,
9 reduced scarcity prices, overall lower prices, and, in
10 particular, lower net revenue.

11 Lower net revenue translates, in turn, into lower
12 incentives for investment. One can provide or a market can
13 provide investment incentives from two primary sources: In
14 an energy-only market, investment incentives derive from
15 scarcity pricing, which occur, obviously, when the market is
16 short.

17 In a capacity market, those incentives, those
18 same incentives, really, effectively the same dollars, are
19 captured in capacity prices. They're really substitutes for
20 one another, and the relationship between the two must be
21 remembered.

22 In effect, the capacity market is creating a
23 market for the required level of reliability. A defined
24 level of reliability is then distributed, using a market-
25 based mechanism to loads, and, in turn, provides incentives
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18895
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1 on the capacity side.

2 Current capacity market issues clearly -- it's
3 well recognized that there are inadequate locational
4 investment signals under the current capacity market. We
5 have in PJM and elsewhere, location and reliability issues,
6 locational retirement issues, and, as a result, we're seeing
7 in New Jersey and have seen elsewhere, out-of-market
8 bilateral contracts.

9 Out-of-market bilateral contracts impose a risk
10 to the entire market design. To the extent that the market
11 needs and requires an out-of-market contract, it's, first of
12 all, evidence that the markets are not working properly,
13 and, secondly, to the extent that those are used, and used
14 more frequently, it undermines the market itself.

15 They tend to be short-term, and, in particular,
16 that's the case for the proposed RMR contracts in PJM. They
17 rely on regulatory negotiations, rather than a market
18 signal, and probably, most importantly, they do not induce
19 new entry. If one pays an existing entity enough money to
20 tide them over for a year or two until transmission is
21 built, clearly, that's not providing a signal for entry,
22 either to transmission or to generation.

23 The final issue with the current capacity market,
24 from my perspective, is that there are actually no explicit
25 market power rules. The disconnect in the current capacity
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1 market between market signals and reliability, includes the
2 fact that load growth past a single year -- in some cases,
3 since we have a daily market, past a single day -- is not
4 reflected in capacity market prices.

5 The farthest out we go on a systematic basis, is
6 a year in PJM. The result is that investment incentives are
7 short-term, rather than long-term. Clearly, it takes time
8 to build units of various types. Clearly, it's longer than
9 a day and longer than a year.

10 One of the fundamental issues of the current
11 market is that it does not match well, the timing of new
12 investment incentives and prices. As I indicated, there's
13 also a locational variation in supply/demand balance that's
14 not reflected in the current market that leads to these
15 issues. Generation retirement is a symptom of that.

16 But even in the overall market, for the reasons I
17 indicated at the very beginning, a capacity market of the
18 type we have now, is unlikely to achieve a stable
19 equilibrium and a target level of reliability, again,
20 because it does not induce entry, because there's not
21 competition for entry, because it's relatively short-term.

22 With the absence of a forward-looking capacity
23 price and market and price signals, a relatively smooth
24 equilibration, as a relatively smooth process, as a likelihood
25 of getting to the desired level of reliability, is quite

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18895
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1 unlikely. It is, in fact, likely to be quite choppy, quite
2 unstable.

3 The absence of a long-term signal, again,
4 probably the most critical result in the absence of a long-
5 term signal, is that it makes competition for new entry more
6 difficult.

7 In PJM, the issue of locational pricing and the
8 difference between the overall market and locational market,
9 is probably best illustrated by the document you don't
10 currently have in front of you, but I know you've all ready,
11 the State of the Market Report.

12 (Laughter.)

13 MR. BOWRING: I don't actually remember the
14 figure or number, but post-the AEP integration, PJM was
15 extremely long in the capacity market and in the overall
16 capacity market. The rational economic equilibrium in a
17 capacity market which is long, is a low price.

18 At the same time, we have areas of PJM where
19 we're clearly short capacity, an obvious disconnect. In
20 fact, if you look at the next slide, you will see that
21 prices in PJM have, in fact, reflected the rational outcome.
22 Prices in PJM, long-term prices, that is, monthly, what
23 passes for long-term prices, monthly, multi, multi-prices,
24 have declined fairly steadily.

25 Last year, price was less than \$20 a megawatt-

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18895
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1 day. Another result of that, for the overall market -- and,
2 again, it's not necessarily an irrational outcome for the
3 overall market, is that net revenues are down.

4 Again, I have repeated this ad nauseam, probably,
5 what the level of net revenues is in PJM, but it clearly is
6 the case, over the entire life of PJM's competitive markets,
7 net revenues, that is, the return to existing investment,
8 and, in fact, the incentive for new investment, is well
9 below that required to incent investment.

10 Again, that's not irrational in the overall
11 market that is long. It is an irrational outcome in areas
12 where we clearly need new capacity investment.

13 The last point I wanted to touch on was market
14 power. As I indicated, and, again, I have repeated many
15 times, in many State-of-the-Market Reports, the capacity
16 markets face market power issues. It's almost endemic to
17 capacity markets. It endemic, as, in fact, I've said.

18 Locational capacity markets are even more
19 susceptible to market power. Clearly, you'd have to have an
20 explicit plan for dealing with that in a market that is
21 going to be locational.

22 One of the advantages of RPM, as it's structured
23 now, is that there are explicit market power rules. Those
24 are critical in order to make that market work.

25 In addition, the conditions about market power
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18895
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1 have been integrated into the market design.

2 For example, mitigation is not applied to new
3 entry. We're relying on competitive forces for new entry in
4 both locational and aggregate markets.

5 That makes sense; it's consistent with the design
6 and consistent with the forward look of the market.

7 Finally, mitigation in the proposed RPM is
8 limited to relatively small local capacity markets. Two of
9 those markets were for time periods when new entry is not
10 required, even in small locational capacity markets. When
11 entry is required, there will be no mitigation.

12 Hopefully that was less than my ten minutes, and
13 we'll all have time to discuss this. Thank you very much.

14 MS. COCHRANE: Betsy, your turn.

15 MS. MOLER: Exelon appreciates the opportunity to
16 participate in this Technical Conference on the important
17 issue of ensuring adequate generation supply. It's an honor
18 and a pleasure to be back at this table.

19 Exelon serves more than 5.1 million retail
20 customers in PJM. We own or control about 33,000 megawatts
21 of generation, of which 26,000 are in PJM.

22 We are vitally concerned about maintaining a
23 reliable system, both today and in the future. In our view,
24 planning now for adequate generation and transmission
25 resources for the long term, is essential to maintaining the
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18895
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1 future system reliability within PJM.

2 Exelon supports PJM's reliability pricing model
3 proposal. We have participated actively over the four-plus
4 years in the stakeholder process. It's been long, but we
5 believe that the result that came out of it, is a very positive
6 one.

7 We believe that the proposed RPM balances all
8 stakeholder interest, load, generation, demand-side
9 response, which is important, and transmission needs. It's
10 a comprehensive proposal to resource adequacy that will
11 result in efficient, stable, and predictable prices for
12 needed generation capacity, including both existing and new
13 capacity and in specific locations with PJM.

14 While we support RPM, as a whole, I want to
15 emphasize today that the view that the critical missing
16 element in PJM under today's rules, is a requirement for a
17 forward procurement process for generation.

18 We believe that a long-term forward procurement
19 requirement is the single most important element of the RPM.
20 If you take nothing else from my remarks, I hope you will
21 remember that.

22 We understand that this Commission and other
23 commissions, and perhaps the PJM Board, is looking for a
24 further compromise on the elements of the RPM. In our view,
25 the long-term forward procurement requirement, should not be
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18895
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1 dropped in any attempt to develop a compromise or reach a
2 consensus on the RPM proposal.

3 Importantly, the RPM, as it is currently
4 proposed, puts both transmission and generation on an equal
5 footing in determining the most efficient solution to
6 maintain system reliability.

7 The RPM also encourages load management, retains
8 the capacity resource deliverability requirement, supports
9 retail access programs, accommodates bilateral supply, and
10 includes market mitigation, all of which are important
11 elements.

12 We believe that addressing resource adequacy is
13 an urgent matter. New transmission and transmission
14 resources require long lead time to be built.

15 Under the existing capacity market design, prices
16 are simply too low to prevent retirement of critical
17 generation or to attract new generation.

18 The result is that PJM must build transmission to
19 compensate for the anticipated retirement of needed
20 generation. That's not a good idea.

21 Building transmission is a lengthy process. It's
22 controversial. It can be inefficient and disruptive to
23 effective long-term transmission planning, when required in
24 response to an unexpected generator retirement.

25 A generator announces it's going to retire, 90
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18895
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1 days later, under the current rules, they can do that.
2 Transmission takes a little longer than that to get
3 permitted and to build.

4 Under the current rules, PJM has not solid
5 information about what generation will retire and when, or
6 what new generation actually will be built in the next few
7 years.

8 PJM's current rules allow loads to purchase
9 capacity on a day-ahead basis, but then you have the anomaly
10 that generation can retire with only 90 days' notice, and
11 PJM has not authority to order anybody to invest in new
12 generation.

13 These rules limit PJM's ability to ensure long-
14 term reliability. To plan and operate a reliable system,
15 PJM must know what generation will be available to serve
16 existing and future needs, and must have sufficient time to
17 react, if information reveals that future generation is not
18 expected to be adequate to ensure reliability.

19 The four-year advance period for resource
20 commitments and price signals in the PJM proposal, are
21 crucial improvements over the existing capacity market.

22 You hear Joe talk about the long-term horizon in
23 PJM. Right now, it's a month to a year. It's not four
24 years.

25 Frankly, during the process, we argued in favor
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18895
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1 of a five-year forward procurement requirement, but the
2 compromise was four years.

3 The need for a forward commitment is clear. It
4 addresses the need to give generators an incentive to build
5 sufficient generation to satisfy the installed reserve
6 margin requirement, while simultaneously addressing the need
7 to expand the transmission system where and when it is
8 necessary to ensure that all areas of the PJM are reliable.

9 There are several benefits to RPM that would be
10 diminished or eliminated entirely, with the forward
11 procurement requirement. First, we believe that forward
12 procurement allows much better integration of PJM's resource
13 adequacy plan, and its transmission planning process, known
14 affectionately as the RTEP.

15 Moreover, sufficient lead time allows for market
16 comparison of generation, transmission, and demand response
17 alternatives to address the reliability concerns. All types
18 of resources are put on an equal footing.

19 Second, forward procurement provides price
20 signals on the value of capacity with sufficient lead time
21 to enable the development of new capacity, whether it's
22 transmission, generation, or demand-side responses by the
23 time it is needed.

24 Third, forward procurement enables developers of
25 generation to participate in the capacity market and to
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18895
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1 compete with incumbents.

2 Fourth, forward procurement allows generators
3 that are retirement candidates, to bid what it will take for
4 them to stay open, and the timeframe ensures that
5 retirements will be known well in advance. That's simply a
6 flaw in the current PJM rules.

7 In sum, adequate generation capacity and a robust
8 transmission system are critical to ensuring reliability.
9 The RPM, with its forward procurement feature, in
10 particular, is a superior market design that will provide
11 more certain information to PJM regional transmission
12 expansion processes, and price incentives to allow ongoing
13 development of an optimal mix of generation, transmission,
14 and demand response.

15 My prepared remarks, which are available, address
16 several specific RPM features in detail, and I will not
17 elaborate here. In sum, we support the PJM RPM -- excuse
18 the acronyms -- we reiterate our view that the forward
19 procurement process component is crucial and we urge the
20 Commission to encourage PJM to file its RPM proposal as soon
21 as possible, so that it can be approved and implemented
22 without further delay. Thank you.

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18895
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1 MS. COCHRANE: Thank you for your comments.

2 The next panelist is Tom Shaw with PEPCO.

3 MR. SHAW: Thank you. I appreciate the
4 opportunity very much to be here. I think it's reflective
5 of the attention that our regulatory commissions in the
6 various jurisdictions we service well represent how
7 important these proceedings are and the issue at hand. I'll
8 take the Commissioner's advice and not try to repeat as many
9 of the things that my two counterparts to my right have
10 said. My remarks are available in hard copy, so I'll try to
11 summarize those and move through it fairly rapidly.

12 In my 34 years at PEPCO Holdings Inc. and its
13 predecessor companies, Delmarva Power and Light and
14 Connective, I've worked on both the generation and
15 transmission sides of the business. As PHI executive vice-
16 president and chief operating officer, I'm currently
17 responsible for the overall operations of PHIs power
18 delivery business.

19 Our three regulated businesses, PEPCO, Delmarva
20 Power and Light, and Atlantic City Electric, deliver
21 approximately 12,000 megawatts to 1.8 million retail
22 customers here in the mid-Atlantic region. We have an
23 ongoing obligation to provide reliable service to our
24 customers at reasonable cost. We rely upon PJM to provide a
25 reliable regional bulk power system. We do not want PJM to

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1 start focusing on short-term price impacts at the expense of
2 long-term system reliability. It is basic physics that
3 transmission has no value without generation and vice-versa;
4 the two are both critical components of a reliable bulk
5 power system. They're not independent alternatives to each
6 other.

7 In order for a capacity market to encourage the
8 appropriate contribution of generation and, I might add,
9 demand side resources to system reliability, it must meet
10 the following objectives: it must give transmission
11 planners adequate advance notice of the addition and
12 retirement of resources, it must provide an economic
13 incentive for the operation of generation and demand side
14 resources at locations where they're most needed, it must
15 provide a forward price signal that encourages long-term
16 generation and demand side resource commitments, it must
17 provide for stable prices that reflects the benefits of
18 generation and demand side resources to the system, it must
19 contain mechanisms to prevent the exercise of market power,
20 it must provide an economic incentive for generation owners
21 to offer the needed operational flexibility to the system --
22 they don't just come on and run, many units have to ramp up
23 and down. It must also provide a forward price upon which
24 investors can rely.

25 While PJM's current capacity construct meets some
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18895
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1 of these objectives, it fails to meet some very important
2 ones. First, when current construction fails to provide PJM
3 planners with notice of where and when generation and demand
4 side resources will be added to the system, this becomes
5 even more critical as PJM starts to use longer planning
6 horizons. Second, because the current construct provides
7 for a single system-wide capacity price, it fails to
8 recognize and reward the need for capacity that is located
9 in constrained areas. Third, because the current construct
10 does not include a forward capacity price, potential
11 resource owners are not encouraged to make the long-term
12 commitments that they need to.

13 The current capacity market fails to provide a
14 price signals that reflects projected resource inadequacies.
15 As a result, little new generation is being built and
16 numerous generation retirements have been announced.

17 Fourth, the current construct forces resource
18 owners to respond to volatile swings in the price of
19 capacity. This has led to the so-called boom/bust pricing
20 and construction cycles. When the expected resource
21 shortages occur, the current construct, if left unchanged,
22 will result in a run-up in prices and the probable
23 commencement of new generation construction. However, by
24 that time, PJM will be over-using stop-gap reliability must-
25 run contracts to maintain the reliability of the system at
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18895
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1 much greater expense than would otherwise be necessary.

2 Fifth, the current construct does not reward
3 resource owners that provide operational flexibility needed
4 by PJM for the reliable operation of the system.

5 Finally, the current construct fails to provide a
6 reliable price signal upon which investors can base their
7 investment decisions.

8 The capacity market does not operate in
9 isolation. It operates in conjunction with the energy
10 market, the ancillary services market, and the regional
11 transmission expansion program process as an integrated
12 process for ensuring the reliable operation of the regional
13 grid. If the capacity market provides a stable source of
14 capacity revenues, resource owners will be able to compete
15 more aggressively in the energy and ancillary service
16 markets, thus leading to reduced prices in those markets.

17 Appropriate market power mitigation measures are
18 in place to ensure that resource owners do not overrecover
19 through a combination of sales into the multiple markets.
20 The establishment of an efficiently-operated capacity market
21 should not be viewed as a short-term fix requiring a planned
22 exit ramp.

23 Some have suggested that an exit ramp leads to an
24 energy-only market. We believe customers should not be
25 exposed to the extreme volatility of such a market and the
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18895
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1 volatility that it would create. We believe that a capacity
2 market must be implemented that provides a forward price
3 signal that encourages the operation and construction of
4 generation and demand side resources where and when they are
5 needed. The commitment provided in response to such a
6 forward price can be used by PJM planners to develop long-
7 range plans for the reliable operation of the regional
8 transmission system. PJM and its stakeholders have spent
9 the last four years developing just such a capacity
10 construct. We look forward to being filed with and approved
11 by this Commission. Thank you.

12 MS. COCHRANE: Thank you for your comments. I'd
13 like to recognize Commissioner Suedeen Kelly who is with us
14 now.

15 Our next panelist is Bob Weishaar, representing
16 the PJM Industrial Customer Coalition.

17 MR. WEISHAAR: Good morning. Thank you for the
18 opportunity. PJM ICC thanks you for the opportunity to
19 comment.

20 I think we've been at the capacity issue probably
21 longer than four years. I remember when we had ICAP EPC
22 working group meetings at PJM looking at the issue of ICAP
23 in conjunction with the energy price cap. Those started
24 soon after the market kicked off back in 1997. Although the
25 acronyms change, the concept, the issue remains the same.

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18895
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1 That's how to provide politically-desired levels of
2 reliability in a competitive market. Some of what I was
3 going to say has already been said, so I will skip through
4 my presentation. I've distributed it to the Staff; there
5 are copies in the back.

6 A couple issues I think we need to focus on. One
7 is the interrelationship with other markets. When this
8 Commission approved locational marginal pricing in 1997, it
9 was based on the theory that LMP would provide sufficient
10 contributions to fixed costs to attract new investment and
11 also provide the right price signals to put that investment
12 in the correct locations.

13 What we have today in PJM is a very healthy
14 generation reserve margin. I think PJM's May 23rd press
15 release quoted the number of 26 percent reserve margin, so
16 systemwide generation adequacy is not really an issue. What
17 we have are locational issues, and I think a lot of folks
18 have been pointing to the capacity market or capacity
19 construct as the culprit, but we haven't really gone back
20 and determined why the theory that was underlying the
21 Commission's 1997 orders approving LMP has not provided the
22 right price signals to encourage or spur investment, either
23 in transmission generation or demand response in the areas
24 that have begun to surface as issues.

25 Another issue we need to focus on throughout this
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18895
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1 debate is what we refer to as pancaked revenue streams for
2 generators. We have to keep in mind that generators today
3 are receiving revenue streams from multiple sources, some of
4 which are captured in PJM's state of the market reports,
5 some that may not be captured in state of the market
6 reports, and the revenue streams are from the energy markets
7 and ancillary service markets. But there have also been
8 stateside regulatory approvals requiring ratepayers to
9 compensate generation-owning utilities, billions of dollars
10 in stranded costs. When we look at the total pot of dollars
11 here, which I encourage the Commission to do, we have to
12 take into account all available revenue streams.

13 Just a comment on the inframarginal issue: as
14 RPM is structured, RPM would compensate all units single
15 clearing price without differentiating generation types,
16 baseload intermediate peaking. That in our opinion is a
17 significant deficiency. We do know that some baseload units
18 are earning significant inframarginal rents. There was a
19 study just released yesterday done by Synapse commissioned
20 by the Pennsylvania Office of Consumer Advocate that zeroed
21 in on this phenomenon for a couple of units in Pennsylvania
22 and demonstrated and quantified the impact of this
23 inframarginal revenue issue.

24 So to take that existing circumstance and to
25 regulatorily mandate a revenue stream on top of it is not,

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1 in our opinion, just and reasonable and cannot be squared
2 with the Federal Power Act. What we do know is that PJM's
3 total market construct, inclusive of the energy piece and
4 ancillary services piece and capacity piece, has attracted
5 new investment, continues to attract new investment, has
6 resulted in a systemwide reserve margin in excess of 25
7 percent. So as we analyze the issue, we can't lose sight of
8 that fact. We can't allow a particular locational issue
9 that has begun to arise to call into question the core
10 components of that construct.

11 Finally, on the issue of an exit strategy, in our
12 opinion, capacity markets are necessary in order to achieve
13 politically-desired levels of reliability. In circumstances
14 where all of the assumptions for a truly competitive market
15 exist, there should not be a need for a capacity construct.
16 So where we have robust transmission construction no or
17 minimal barriers to generation entry and exit, where we have
18 adequate demand elasticity, where we have full transparency
19 in information flow, the need for a capacity construct
20 should fade away.

21 Bottom line, my clients are looking at increasing
22 electricity prices. We see often that those are attributed
23 to increases in fuel prices. We appreciate that fact, but
24 the bottom line is that customer bills are not calculated on
25 a fuel adjusted basis, they're calculated on a total cost
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1 basis and customers should not be asked to pay more when
2 reliability has been fine in PJM and there's no commitment
3 and the additional revenue extraction from ratepayers will
4 actually go to physical solutions to the problem.

5 Thank you.

6 MS. COCHRANE: Thank you, Bob.

7 Our next panelist is Patrick McCullar, with the
8 Delaware Municipal Electric Corporation.

9 MR. MC CULLAR: Thank you very much, Anna. Good
10 morning everyone.

11 We've been invited here today to discuss the
12 capacity situation in PJM RTO and to provide additional
13 information to the Federal Energy Regulatory Commission and
14 state public utility commissions that will assist them in
15 providing guidance to the industry on the issues and
16 perceived problems that may exist in the capacity construct
17 currently in use.

18 I represent the views of my company, Delaware
19 Municipal Electric Corporation, which is a joint action
20 agency serving nine distribution utilities on the Delmarva
21 Peninsula with a load slightly over 400 megawatts. We also
22 represent the opinions of members of the PJM Public Power
23 Coalition. The Coalition is made up of municipal,
24 cooperative and investor-owned load-serving entities
25 operating inside the PJM footprint. My company and many of
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1 the Coalition members are also generation owners and
2 transmission owners.

3 I currently serve as chairman of the PJM Members
4 Committee, the principal stakeholder and governance body of
5 PJM and the PJM Public Power Coalition is an active
6 participant in the governance stakeholder process. They're
7 very supportive of the excellent staff at the
8 interconnection.

9 Electric supply is an integrated system with many
10 parts. Rather than discuss markets, we should focus on the
11 integral parts of the system and how they function together
12 to accomplish the work of the system. The system cannot be
13 improved by working on one part at a time in isolation, but
14 must be analyzed and improved as an integrated system. No
15 amount of greasing of one part will improve the system if
16 the other parts of the system are not working properly. It
17 goes without saying that you must work on each part at the
18 correct time. To work on a part that's not broken while
19 ignoring a broken part is unwise, and I submit that we've
20 had some unwise actions in the electric supply system.

21 What are the goals of the capacity construct? To
22 assure an appropriate level of investment and the optimal
23 mix of generation capacity within the system to assure
24 availability of supply and reliability given the long lead
25 times of construction and to ensure the ability of the

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1 system to meet demand given its inherent fluctuation and
2 uncertainty and the non-storability of power and to
3 encourage a robust long-term bilateral forward market for
4 power supply for long-term price stability ensurance.

5 To answer the question of whether or not the
6 current capacity construct in conjunction with the other
7 parts of the integrated system meets the above goals
8 currently, one need only look at the incredible amount of
9 new capacity built in the PJM footprint in the last seven
10 years. Over 16,000 megawatts was added to the PJM classic
11 footprint from 1997 to 2003. According to PJM's current
12 numbers, in the next four years an additional 10 to 20
13 percent capacity will be added in the classic PJM footprint,
14 that's 7,000 to 14,000 megawatts of additional capacity.

15 I cannot arrive at any other conclusion other
16 than the current system is sufficient to encourage investors
17 to arrive at the conclusion that capacity, energy and
18 ancillary services revenues from new generation assets would
19 be sufficient over the long-term to provide a higher rate of
20 return than other available investments. Certainly there is
21 no need for an exit strategy from a working capacity
22 construct.

23 However, one failing of the current integrated
24 system is its inability to encourage the correct mix of
25 generation assets for the long term. Most of the new assets

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1 built have been smaller-scale natural gas fired intermediate
2 and peaking generation assets. What is long overdue and
3 sorely needed is investment in new baseloaded large-scale
4 generation assets utilizing economic and abundant fuels.

5 Why has this not happened? It's certainly not
6 due to a lack of investment capital, nor is the failure of
7 the capacity construct. It is another broken part of the
8 PJM system. Capacity of the electric system really has two
9 parts: generation capacity, the ability to produce a unit
10 of energy, and transmission capacity, the ability to deliver
11 a unit of produced energy. Each is worthless without the
12 other.

13 There are two principal reasons that current
14 investors in generation assets are not recovering their
15 desired rate of return through capacity and energy revenues
16 from recent investments and new investors are not rushing to
17 invest in new baseload assets. First, overbuilding of new
18 capacity has flooded the market and supply and demand
19 economics has forced the price of generation capacity to
20 predictably low levels. Second, the transmission system has
21 been studiously neglected, resulting in a failure of the
22 universal deliverability concept.

23 PJM has promoted the theory of universally-
24 deliverable generation but has not planned and constructed
25 the transmission system to make it a reality. If the

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1 universal deliverability concept had been honored in
2 reality, rather than in theory over the past seven years,
3 there would be no concerns for reliability in New Jersey,
4 the Delmarva Peninsula, or any other part of PJM. Indeed,
5 the entire justification of RTO formation and industry
6 restructuring is to capture the efficiency and economics of
7 the integrated electric system for the benefit of end users
8 through competitive markets. But we have not built a
9 competitive market yet. The principal broken part, the
10 transmission system, has yet to be fixed.

11 The lack of transmission capacity adequacy
12 impedes the ability of sufficient assets to compete with
13 less-efficient assets because they cannot be delivered to
14 the loads who would otherwise select the more competitive
15 asset. This is the area where FERC and state commissions
16 should focus their efforts.

17 Reforms to the regional transmission expansion
18 planning process and construction of needed transmission
19 upgrades are the key to resolving the current transmission
20 capacity adequacy problems. If we fail to fix this broken
21 part, neither capacity construct changes nor any other
22 effort will result in real improvements in the integrated
23 electric system. To simply give more money to generation
24 owners will result only in further increasing the current
25 high power prices and will not assure a robust competitive
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18895
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31

1 and reliable power system.

2 Thank you for the opportunity to make these
3 comments.

4 MS. COCHRANE: Thank you.

5 Our next panelist is Lynne Kiesling, a professor
6 at Northwestern University and also with the International
7 Foundation for Research in Experimental Economics.

8 MS. KIESLING: Thank you. I'm going to take the
9 liberty of being the lone academic on the panel to be a
10 little more conceptual and theoretical, but hopefully not
11 stray into the perfection trap that Commissioner Brownell
12 correctly warned us against.

13 Thank you for inviting me to participate in this
14 technical conference on design of capacity market. I am
15 Director of the Center for Applied Energy Research at the
16 International Foundation for Research in Experimental
17 Economics and a senior lecturer in the Department of
18 Economics at Northwestern University.

19 The situation in which we find ourselves is the
20 desire to achieve a robust reliable network during and after
21 the transition towards integrated competitive wholesale and
22 retail markets. In that transition, we face concerns about
23 long-term reliability and the investment to provide
24 reliability, a perceived need for a centralized resource
25 adequacy planning process, immature integrated physical and
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18895
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32

1 financial wholesale markets, immature demand side
2 participation in both wholesale and retail parts of the
3 value chain, and reluctance to allow wholesale energy spot
4 price fluctuations to signal investment opportunities to
5 entrepreneurs.

6 The question of reliability is an intertemporal
7 supply demand coordination problem. The basic question is
8 how to facilitate optimal future consumption of resource
9 allocations. Our toolkit essentially consists of four
10 tools, some of which have been discussed by my previous
11 panelists: more generation, more transmission, less demand,
12 and technological change that could affect any or all of the
13 other three tools. No one knows the optimal combination of
14 those four tools.

15 A capacity market construct with locational
16 product definition is one way to deal with the regulatory
17 distortion imposed by price caps. In many ways, it is
18 inferior to integrated forward energy markets, which do a
19 better job of picking that optimal resource portfolio. And,
20 of course, optimal resource portfolios do change over time.
21 The information requirements to pick optimal resource
22 portfolios in a centralized manner are large, as the
23 knowledge required to discover the optimal resource
24 portfolio is diffuse and distributed among market
25 participants, customers, and entrepreneurs who are the
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18895
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33

1 agents in the electric power network. The intertemporal
2 nature of the problem and the time that some resources take
3 to build mean that the market process in question has
4 delivery commitment in the future, which means integrated
5 spot and forward energy markets.

6 I see the target design as a market process in
7 which generation, transmission demand and the new technology
8 can all participate in producing electric power or its
9 equivalent in demand reduction, in which a consummated
10 forward transaction commits the agents in the transaction to
11 meet the agreed obligation by the date specified in the
12 contract.

13 Note that this is a decentralized contractual
14 approach to the resource adequacy question, not a
15 centralized regulatory approach. The important market
16 design elements are four: first, a double-sided market in
17 which the transaction is the capacity to deliver an
18 additional megawatt in X years, where X right now is
19 proposed to be four load-serving entities on the demand side
20 with clear property rights and legal definitions of their
21 obligations, three, generation transmission demand reduction
22 and new technology resources, all three to participate on
23 the supply side, finally, transparent market rules governing
24 submission of bids and offers and determining the market
25 clearing price.

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34

1 This transaction, like similar transactions in
2 other infrastructure industries, can occur through existing
3 financial markets. If property rights are well defined,
4 transaction costs are low and regulatory barriers to the
5 equivalent participation of generation, transmission demand
6 reduction, and new technologies are low. However, these
7 three assumptions do not currently hold, so ISOs and RTOs
8 that use capacity markets then have artificial demand curves
9 and do not treat all four types of resources equivalently.
10 So if my analysis is correct, then capacity market may be a
11 valuable short-run mechanism while demand side participation
12 develops, property rights clarify, and forward energy
13 markets evolve and provide intertemporal resource allocation
14 signals, but the design of that capacity market is crucial,
15 obviously, or we wouldn't be here today.

16 First, the capacity market design must treat
17 these four resources equivalently. Second, the capacity
18 market must be allowed to evolve, dare I say atrophy, as
19 integrated spot and forward financial markets evolve;
20 enshrining a capacity market for all time does not
21 contribute to a resilient, agile, flexible network or set of
22 markets. Imagine if 1850's law had dictated the existence
23 in perpetuity of a capacity market for the production of
24 whale oil. We'd do a very bad job in this industry of
25 letting dime stores go extinct.

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1 But the extinction of the capacity market
2 construct as integrated financial markets evolve is one key
3 to adaptability. The way to operationalize the retirement
4 of the capacity market is to establish transparent rules for
5 its decreased use as the volume approaches the desired
6 reserve margin. If the capacity market is to serve as a
7 constructive bridge to integrate the competitive market, it
8 also needs to be tested carefully. My natural inclination
9 is to recommend experimental testing of market designs.

10 (Laughter.)

11 MS. KIESLING: Experimental economics uses a
12 laboratory environment and profit-motivated human
13 participants to test bed market designs which complements
14 system level simulations that are common in the industry by
15 generating knowledge about how real humans with profit
16 incentives will behave in a proposed market environment.
17 Experimental testing can catch design flaws and allow
18 correction before the market is implemented.

19 Thus, I suggest the RTO capacity market policy
20 should include equivalent participation of generation,
21 transmission demand, and new technology resources,
22 transparent rules for the capacity markets retirement when
23 it is no longer needed, working diligently to decrease the
24 transaction costs hampering the development of integrated
25 spot and forward markets for electricity products, which has

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36

1 been done in places like Australia. That can provide useful
2 examples and lessons.

3 Finally, extensive testing, preferably using
4 experimental economic methodology. Forward markets are the
5 key to a resilient and agile industry and provide the
6 clearest price signals to investors. Forward energy markets
7 are superior to generator-specific capacity markets
8 precisely because they provide the lowest cost means of
9 transmitting intertemporal opportunity cost information to
10 the parties with the widest variety of possible ways to
11 respond. If a capacity market is necessary to get us there,
12 it has to be thoughtfully designed, carefully tested, and
13 allowed to retire.

14 Thank you.

15 MS. COCHRANE: Thank you, Lynne.

16 Our next panelist is Brian Chin, an analyst with
17 Citigroup Smith Barney.

18 MR. CHIN: Good morning. My name is Brian Chin,
19 I'm the Energy Merchant Stock Analyst at Smith Barney
20 Citigroup. My colleague, Greg Gordon, covers electric
21 utilities, and together we cover the electric utilities and
22 energy merchant space for Smith Barney.

23 Before I begin, I'd like to thank the Commission
24 for the opportunity to address the issue. We've written a
25 series of reports on the capacity markets issue since the
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18895
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37

1 early part of this year and have had many conversations with
2 investors on the topic. Copies of our reports are actually
3 located in the back. We did bring a handful of them and I'm
4 happy to send them to you to post my comments here if you're
5 interested in looking at our comments. Let me summarize our
6 current views in five major points.

7 Point one, capacity markets should reduce price
8 volatility. We believe volatility and price uncertainty in
9 deregulated markets stems from a supply curve that by
10 technological necessity has a sharpened flexion point. Once
11 demand exceeds a region's inflexion point, the variable cost
12 of power increases exponentially, resulting in power spikes.
13 The practical result of this from an investment perspective
14 is that power spikes are highly uncertain, severe, and
15 difficult to model.

16 We believe capacity markets should mitigate this
17 volatility. The various capacity market proposals to a
18 greater or lesser extent, each help unbundle generator
19 revenue streams into a fixed and variable component. The
20 search to add an element of revenue certainty to generate a
21 forecast which, in turn, creates a less risky investment
22 environment, resulting in either fuel retirements or a lower
23 threshold for expansion of investment. This allows for a
24 longer, more stretched supply curve which should reduce the
25 frequency of price spikes at every stage of the over- and
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1 undersupply of the capacity cycle.

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1 We believe, in spite of several valid concerns
2 that require addressing, multi-year forward auctions do add
3 to the revenue certainty picture and that should assist in
4 volatility mitigation.

5 Point Two: Lower volatility should result in
6 lower cost of capital and a more stable investor base. We
7 believe, ultimately, capacity markets should contribute to a
8 lower overall cost of generation.

9 This is because, with reduced price volatility,
10 wholesale generation become easier to forecast, and, hence,
11 finance. We should see a wider investor base willing to
12 invest in the sector concurrently with this phenomenon.

13 Currently, after the boom-and-bust of the
14 merchant capacity cycle in 2000 through 2004, most risk-
15 tolerant investors and speculators tend to invest in pure
16 play generation, ranging from private equity partnerships to
17 stressed asset investors and hedge funds.

18 This, in and of itself, isn't bad. After all,
19 investors are supposed to bear the risk of a fully
20 deregulated market structure, but the natural outcome or
21 corollary with this outcome, is rapid asset turnover among
22 who owns the investments, and a higher percent of volatile
23 investors, rather than stable, going-concern companies that
24 either own or invest in generation.

25 Lower volatility should attract a wider class of
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18895
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1 mainstream investors, which goes hand-in-hand with lower
2 cost of capital.

3 Point Three: The best time to implement capacity
4 markets, in our opinion, is at the mid-cycle of
5 expectations. In my opinion, it would be politically
6 difficult to rationalize a capacity burden on consumers in
7 over-supplied markets, because critics of capacity markets
8 will argue there is no visible need for such structures when
9 capacity is in abundance.

10 Likewise, when capacity is short, critics will
11 point to spiking wholesale prices and will argue investors
12 are already receiving an investment signal.

13 In my opinion, PJM, in aggregate, is at the mid-
14 cycle of expectations, currently. So, if there is a time to
15 consider looking at a capacity market implementation, now is
16 probably the optimal time.

17 Point Four: Critics of capacity markets have
18 raised a number of meaningful issues that we believe should
19 not be dismissed out of hand. A, It is uncertain, how
20 capacity markets should best be integrated with broader
21 resource planning; B, multi-year forward auctions are
22 subject to forecasting error, and, C, it is not yet clear,
23 which capacity market structure best balances cost,
24 reliability, and price stability.

25 Generally, most of the comments we've heard
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1 criticizing capacity markets, seem to revolve around these
2 issues, and they are meaningful and significant to us.

3 Five: Investors have been to take notice.
4 Capacity markets have been watched with increasing interest
5 by investors.

6 In fact, there are actually institutional
7 investors in the audience right now that reflect the keen
8 observation that the investing community has taken in this
9 space.

10 Recent events such as the Elcon decision on May
11 13th and the LICAP proposed decision yesterday by ALJ Judge
12 McCartney, have provided signals that have generated
13 increased investor interest.

14 It is my opinion that the implementation of
15 capacity markets, should elicit a meaningful investment
16 response. Thank you. This concludes my comments. I look
17 forward to your questions.

18 MS. COCHRANE: Thank you, Brian. Our next
19 panelist is Roy Shanker. You can say whatever you want,
20 Roy.

21 (Laughter.)

22 MR. SHANKER: Good morning. Thank you for having
23 me today. As usual, these are my comments, not those of my
24 clients.

25 I started off in pretty much the same position
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42

1 where Joe Bowring did. If you have a mandated energy cap
2 and a mandated reserve margin reliability, you're going to
3 be short money.

4 There's a figure that I've added to the comments
5 I've distributed at the back as sort of a simple-minded
6 supply/demand curve. It shows what happens when you
7 truncate prices or shift the supply curve.

8 This is posted. I don't have enough copies for
9 everybody. It just makes the simple point that it's not one
10 class of generators that are short income; it's all
11 generators.

12 It's not peakers, it's not base load; it's
13 everybody. We're suppressing the clearing prices through
14 other market means, and we've got to come up with a
15 mechanism to come up with the missing money.

16 Capacity markets are the way to come up with the
17 missing money. The question is only about how do we do that
18 efficiently. How do we design in as least-cost a manner as
19 possible, while complementing other market design elements,
20 assuring reliability, and in the context of this discussion,
21 wondering about whether or not there's a transition
22 possibility out of a capacity-based market system, to an
23 energy-only market system.

24 In the abstract, one might argue that both the
25 status quo for the PJM capacity market and the RPM proposal

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43

1 from PJM, can meet at least the requirement of replacing the
2 missing money.

3 The vertical demand curve of the status quo, with
4 prices capped at a sufficiently-high deficiency charge,
5 which support new entry, just as well as the downward
6 sloping demand curve of the RPM --

7 The issue becomes, which of those mechanisms or
8 other alternatives are better in terms of the criteria we
9 stated in terms of efficiency and complementing the rest of
10 the market?

11 What's become clear from the debate so far, is
12 that the status quo accomplishes these objectives in a
13 fashion that conveys much greater operating and reliability,
14 as well as financial risk to all market participants.

15 It also appears inferior with respect to the
16 ability to translate the transfer to an energy-only market.

17 In turn, these risks, as Brian has talked about,
18 will translate into a much higher likelihood of the market
19 either failing, in general, that needed reliability
20 resources will not be built, and that there will be a
21 significant external intervention, and all this will be
22 ultimately at a much higher cost to all participants.

23 Alternatively, what we've been presented with in
24 the RPM design, is an explicit design intended to reduce and
25 remove these areas of risks, send the proper price signals

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18895
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44

1 and incentives, via locational pricing and new transfer
2 rights, while leading to a more stable pricing and greater
3 likelihood of maintaining the needed level of adequacy
4 resources, and in turn, lowering costs for suppliers and
5 load.

6 From an economic perspective, it appears to be
7 the most efficient solution for meeting these combined
8 requirements. Further, while not perfect, the net energy
9 margin component of the pricing of the demand curve within
10 the RPM proposal, offers a reasonably flexible mechanism for
11 transitioning to, or at least attempting to transition to an
12 energy-only market. I can talk about that a little later.

13 With respect to reliability, the RPM is the clear
14 winner over the status quo. The current market system
15 assumes all generation is the same with respect to adequacy.

16 We know that's not true. We couldn't be in a
17 surplus market with 25-percent reserve margins and still be
18 looking at situations where we're worried about local
19 reliability.

20 Clearly, something is broken; clearly, we're not
21 sending the right price signal in some situations; clearly,
22 there is an element of the capacity market design now that
23 is missing a vital piece of information to tell people where
24 to locate and to create the incentives to match up the
25 development of capacity expansion with the transmission
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1 system.

2 The locational aspects of the RPM proposal,
3 directly overcome this deficiency by recognizing the fact
4 that all generating supplies are not the same, and, in turn,
5 it will procure, to the extent necessary, different levels
6 of capacity where it's needed.

7 It also creates associate property rights for
8 those that expand the system, putting it on parity between
9 transmission and generation.

10 RPM also solves another fundamental weakness in
11 the existing market design. This was spoken about a little
12 before. That's exactly the basic problem we see here in
13 other market designs.

14 There's a mismatch between the time step, between
15 expansion of the transmission system, and the commitment for
16 generation resources. When those two things are out of
17 phase, you find the need for out-of-market activities like
18 RMR contracts, which, as Joe discussed, are very disruptive
19 in terms of price signals.

20 By putting regional transmission planning in sync
21 with the forward capacity obligations, RPM immediately
22 resolves this problem and further enhances system
23 reliability and planning.

24 None of the other proposals we've heard of, the
25 status quo or any of the alternatives being discussed, have

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18895
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46

1 the property of putting these two elements in sync.

2 The same is true for the other market reliability
3 elements that are just load-following and quick-start
4 capability. Indeed, it's just the recognition of the
5 potential physical risk to system security, the status quo
6 that drove the PJM staff to incorporate these features into
7 the RMP market design, we shouldn't lose sight of that, that
8 underlying all of this is physical security concerns.

9 On the other side, there's a very material
10 difference in the risk on the pricing side of the current
11 market design that interacts with physical reliability,
12 discouraging adequate supplies, when needed, and raising
13 overall costs.

14 The status quo with a vertical curve, tends to
15 lead to the boom-and-bust cycle we've talked about. Prices
16 go through cycles of being very high or being very
17 depressed.

18 The pricing volatility and the financial and
19 regulatory risks for suppliers attempting to finance new
20 facilities in this market, raise their costs. This is
21 exactly what RPM was talking about, and those prices
22 ultimately get passed on to the consumers.

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18895
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47

1 Think through the kind of response you'd get if
2 you went to a mortgage lender and you tell him, don't worry;
3 on average, about a third of the years I'll earn almost
4 nothing, but over the lifecycle of my ownership of the house
5 I'll earn enough to carry the payments for the mortgage.
6 PJM's dynamic market simulation shows that this is exactly
7 the type of result we're going to get. The vertical demand
8 curve, having very low price, is about a third of the time.
9 Further, when prices are high and provide income for long-
10 term revenues, the overall system is experiencing a capacity
11 deficiency affecting reliability.

12 Now think about going in to that lender and
13 saying don't worry, I make up my money in the high price
14 years, but that's when the system is physically short.

15 Reliability is in jeopardy and it is the time
16 when regulators are most likely to intervene in the market
17 system and potentially depress those prices again.
18 Ultimately you have to assume that in a risk profile like
19 this the cost of investing in the market is going to go up,
20 those costs and those risks are going to get passed directly
21 on in terms of end prices to consumers.

22 RPM essentially, through the use of the demand
23 curve, the downward sloping demand curve takes away this
24 volatility and these types of risks. The cost impacts are
25 very clear. We're talking billions of dollars of

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18895
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48

1 difference. We're going to have a presentation later from
2 Mr. Hobbs that may go through some of this, but the earlier
3 results in January show about a \$30 to \$50 per peak kW year
4 difference in prices. Think about that in the context of a
5 150,000 megawatt system; we're talking billions of dollars
6 of potential equilibrium price differentials per year.
7 There's a huge amount of money associated with the risks
8 that Brian is talking about. This occurs assuming no change
9 in the cost of funds.

10 The simulations that PJM did assume a constant
11 cost of capital on 150,000 megawatt market in PJM using the
12 new entry costs Mr. Bowring has developed. A 1 percent cost
13 differential in the cost of capital translates to about \$675
14 million a year in differential costs to consumers. That's
15 the price premium we pay. And I think it's a lot more than
16 1 percent. That's the price premium we all pay as consumers
17 here, steady state, by not removing volatility out of these
18 markets.

19 The final comments have to do with the transition
20 to an energy only market. One of the mechanisms within the
21 European design is demand curves are set based on the net
22 cost of new entry. It has a trailing five-year mechanism to
23 subtract out from the cost of new entry the average margins
24 that are earned. That's an incredibly powerful tool for
25 energy market mitigation which we might also want to talk

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18895
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49

1 about. But one of the other attributes that it has, if we
2 choose to use it, is that by raising the price caps over
3 time presumably the netting margin will go up and the
4 capacity market could atrophy on its own.

5 One element that's needed that we usually don't
6 talk about that has to complement that is that it becomes
7 very important to couple that with the ability ultimately to
8 discriminate against loads that cannot point to physical
9 resources. Because at some point we do have to shed load
10 and if you don't want to socialize that risk, you're going
11 to need in an energy only market the ability to bump off the
12 system the people that don't have resources. That
13 transition step is a little more difficult, but certainly on
14 the pricing side alone the RPM mechanism is very flexible in
15 that regard.

16 That's the end of my comments. Thank you.

17 MS. COCHRANE: Thank you, Roy.

18 Thank you all for your prepared remarks. We'll
19 open now to questions and answers and discussion. I want to
20 point out to the Commission Staff behind me, we have a
21 couple of mikes open at the table. If you guys have
22 questions, you can come on up and there's handheld mikes for
23 the state commissioners and for our Commissioners if they
24 have questions.

25 Derek?

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18895
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1 MR. BANDERA: I have a question for Bob and Pat.
2 In terms of your perception of the overall PJM market, you
3 pointed to the excess capacities that were available sort of
4 in your remarks, but obviously they aren't, as the other
5 panelists have said, deliverable. Is your vision of how the
6 process should be working that the process should be just
7 building the transmission to make sure that all those
8 resources are deliverable? An alternative to the RPM
9 proposal is to sort of have a transmission-based process
10 that makes sure that when units may retire, or something
11 like that, that the transmission is already in place to take
12 care of that. Is that what you view as the alternative to
13 the RPM?

14 MR. MC CULLAR: Yes, to some extent, Derek. We
15 believe, as I said in my comments, it's an integrated system
16 and you cannot work on any part in isolation and achieve the
17 goal. We need two substantial things to occur: one, we
18 need the integrated planning system to step up and start
19 making an open-eyed evaluation of the probability of
20 retirement of existing generation assets due to age or
21 economic conditions, et cetera, and incorporate that into
22 the planning process.

23 As I stated, the universal deliverability
24 concept, that has been on the books for many years but we've
25 never achieved in reality, should alleviate to a great
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18895
DAV

51

1 extent the threat of sudden retirements of assets by
2 allowing other similarly-economic assets to deliver to the
3 load that is now stranded by the retirement of some asset,
4 thereby eliminating the reliability problem.

5 We have to do these two pieces in conjunction.
6 We can't just continue to build assets in the wrong places
7 and not be able to deliver them to solve local reliability
8 problems. It's not just a generation solution, because as
9 we all know there are extraneous circumstances and
10 situations that would prevent the location of generation
11 where the LMP system is pointing at. Siting regulations,
12 local community interest, lack of availability of fuel
13 supply to locations, all of those push against locating
14 resources in some of those places that LMP is pushing at.
15 The solution is deliverability through the transmission
16 system to those places that we can't drop a generation asset
17 into.

18 MR. WEISHAAR: Ditto.

19 (Laughter.)

20 MR. BANDERA: Joe, do you have a response?

21 MR. BOWRING: I think a lot of what Pat said
22 makes sense in part, that is, clearly it does make sense to
23 plan the system as a unified whole. It clearly makes sense
24 to think about transmission investment as well as generation
25 investment. But at the same time, it does not make sense to
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18895
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52

1 ignore the facts we're facing right now about investment in
2 capacity and investment in new generation. Deliverability
3 still remains an objective and part of the PJM planning
4 process. PJM has recently moved towards extending the
5 length of the transmission planning process as well. Steve
6 Herling's going to talk more about that this afternoon. But
7 I don't think anything Pat said suggests that we don't need
8 to resolve the capacity market design issue now.

9 MR. SHANKER: There's a mismatch in Pat's
10 comments that you need to be clear about. First, universal
11 deliverability -- and Steve is going to talk about this more
12 -- doesn't address, in terms of the criteria we use, a fine
13 enough definition of locality to assure the absence of more
14 detailed local reliability problems. If it did, all the
15 existing generation passes those tests and we still see a
16 situation where retirements cause a problem, even though the
17 system is surplus.

18 The issue still becomes assume that you build all
19 the transmission you want -- do it irrationally, spend too
20 much on transmission at some point. All we're doing is
21 delaying the point at which we will have to deal with this
22 notion of the missing money and the kind of compensation
23 that's needed in an equilibrium system to keep people coming
24 in. If you want to delay this two or three years, that's
25 fine. If you want to build excess transmission, that's

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18895
DAV

53

1 fine. But we're still going to get to a point where, under
2 any view of the markets, under any construct if we're going
3 to cap prices and have an assured or mandated reliability
4 level, we're going to have to pay for the capacity. At
5 issue is efficiency. If all that would happen with
6 excessive transmission construction is that we would see the
7 locational differentials go toward zero, we'd still be
8 operating under a boom/bust system or a demand curve system
9 that is going to be necessary to bring the new capacity into
10 the market.

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18895
DAV

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1 MR. SINGH: There's a lot of people who said the
2 term "missing money" is kind of focusing on the wrong place
3 because they're saying the focus should be on getting new
4 investment, not paying a generation that's already there.
5 But then if you think through it further, there is a point
6 that goes to Bob's and Patrick's comments on transmission.

7 Assuming, you can't build transmission, what
8 invariably happens is the RTO does RMR contracts, so there
9 is that missing money, then, in the form of this unhedgeable
10 uplift. The question that I would ask you is, are you
11 concerned about them seeing charges in RMR systems? If you
12 don't have to pay anything, that's the best, but you do have
13 to pay eventually someplace. Would it not be better to put
14 those costs in the market through something that you could
15 buy and basically hedge a locational ICAP?

16 MR. McCULLAR: It's a good question. We believe
17 RMR contracts are going to be a necessity from time to time
18 unless PJM is successful in perfectly syncing the planning
19 and construction of transmission with the load growth.
20 That's a virtual impossibility because nobody announces two
21 years in advance where they're going to build the load and
22 where the demand's going to come from. It's just an
23 inherent nature of the market.

24 There are going to be times, as time goes
25 forward, that your RTEP, your transmission planning, is not
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18895
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55

1 perfect, and you're going to have localized problems that
2 will develop. I think RMR contracts should be viewed as a
3 least-cost bridge between the development of the locational
4 problems and the catching up of the transmission system
5 construction. I think that is infinitely more desirable to
6 me as a load-serving entity representative -- you know, the
7 guys who write the checks for all this -- than nuking the
8 market by rewarding all generation owners for local
9 reliability, points-to-point problems.

10 MS. COCHRANE: I think Betsy would like to
11 respond.

12 MS. MOLER: I would like to comment. I think it
13 is naive to pretend that we can build transmission in
14 advance and ignore what generation is or is not going to get
15 built. Transmission is expensive. It's controversial to
16 sight. It takes a lot longer inevitably, particularly in
17 highly congested areas, which is a lot of PJM. You somehow
18 have to get to the point where you're putting generation and
19 transmission on an equal plane.

20 I don't think that PJM should be expected to
21 anticipate what generators might retire and try to have
22 parties build transmission in advance, based upon their
23 theory about what generators might retire. You've got to
24 sync the two up, which is a whole reason to do e-flow
25 procurement.

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18895
DAV

56

1 MR. SINGH: Betsy, one question I would ask you
2 is you emphasized a lot on the forward procurement, and I
3 sort of see that. But there are concerns that some other
4 people have brought up on the issue of uncertainty, the
5 issue of, perhaps, LSCs not then buying for themselves, and
6 PJM becoming a big provider of last resort. Are these
7 concerns things that you sort of disagree with or do they
8 not apply to your particular company? If you had to pick
9 one of the two locations or forward procurement, which do
10 you think would be more important?

11 MS. MOLER: LSCs have an obligation -- whether
12 it's state law or municipal law, depending on how they're
13 governed -- to serve their customers. I don't know of a
14 single LSE that doesn't take that seriously. We spend a
15 heck of a lot of time thinking about what our load's going
16 to be and planning to serve it. It is a concern. I believe
17 it's adequately dealt with in state law.

18 However, to the extent you are a part of a large
19 region, the rules have to be compatible. I would posit that
20 you should not choose between the forward procurement and
21 locational pricing. I think they're both really important,
22 so I don't accept the premise that you have to choose.

23 MR. TIGER: If I could follow up?

24 MR. SHANKER: I'm sorry. Something that I'm sort
25 of uncomfortable letting stand is the notion that RMR is

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18895
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57

1 sort of beneficial when it has to occur, it's least cost,
2 and we shouldn't have windfalls to other people in a
3 clearing situation. Let's take them a piece at a time. I
4 think Joe alluded to this about the inefficiency of RMR.

5 First off, if you're going to essentially seize
6 assets and price discriminate, RMR is cheaper. I thought we
7 were here to talk about markets. Let's pull that off the
8 table.

9 Second, is the notion of a windfall to other
10 market participants. Well, if all the load in an area fails
11 the hedge, okay, then everybody on the market side that is
12 selling is essentially stuck with a business cycle of spot
13 prices. One of the benefits of the dynamic simulation we
14 went through is showing you that over the business cycle we
15 are roughly going to average net cost of new entry, so you
16 need the higher prices during some period of the business
17 cycle to do it. Alternatively, if you don't want to face
18 those high prices and you're on the other side, you're at
19 load, and you say, geez, I don't want to see those guys get
20 the windfall, just step up and hedge yourself long term,
21 then you won't have the problem.

22 There's no magic to this. Everybody needs to
23 average that net cost of new entry. Every type of
24 generation -- baseload, peaking, intermediate -- has to get
25 it over the business cycle to make the adequate returns to
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18895
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58

1 stay in the market. If you're uncomfortable with the notion
2 that some people are going to get high prices when things
3 are short, that's only because you failed the hedge in a
4 portion of the cycle where you could pay the long-term
5 average cost, and everybody would be at equilibrium for
6 that.

7 If you predicate that everybody's at spot, then
8 one of the things, then one of the things that goes with it
9 is that sometimes prices are high, and those people need
10 those prices to stay in for the cycle. This notion that
11 somehow price discrimination is good and eliminating these
12 "windfalls" for other people is just fundamentally wrong;
13 it's not how the markets work. Not only that, it leads to
14 undercompensation. As Joe said in his initial comments, it
15 discourages new entry.

16 MR. TIGER: Two questions to follow up, perhaps,
17 on the new entry question, and then maybe go back to
18 Ms Moler on transmission. For both Roy and Brian, you
19 talked about investors being very interested in locational
20 capacity markets, that people are following the issue. A
21 question that I have is, is that about retention or the
22 value of the current generation, or are these the type of
23 investors that are actually considering making an investment
24 based on a four-year out, one-year commitment?

25 I can understand that they would be very
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18895
DAV

59

1 interested in the value of current generation. I would be
2 interested to hear are you having conversations with people
3 who are thinking about making a forward commitment on what
4 is essentially an uncontracted basis, or is it direct;
5 you're hoping somebody will contract because they're short?

6 MR. CHIN: When we talk with investors looking at
7 the space -- when I say investors, I need to clarify my
8 comments -- we talk with investors who invest in the
9 generating entities that build the generation companies. So
10 I'm not talking about the companies that actually build the
11 generation, but from your perspective I can see how that
12 would be viewed as an investor also.

13 When we talk with investors about looking at
14 forward generation, what you find is a very strong
15 reluctance to build generation. When there is uncertainty
16 over contracting, there's no more of that view that if you
17 build it, they will come. Instead, there is a view that,
18 due to the high level of uncertainty in contracting, and due
19 to the inefficiencies of a forward market, which hasn't
20 evolved sufficiently, as Professor Kiesling said, you find
21 that investors place a high premium, a high risk to equity,
22 and risk to capital, when they're looking at the space. As
23 a result, if they do look at the space, they'll do it only
24 from a distressed asset standpoint. So the investors that
25 are looking at the space and picking up current generation
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18895
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60

1 assets tend to be a more stressed asset investor, vultures,
2 speculators, folks looking at picking up an asset on the
3 cheap, and they're hoping at some point the supply and
4 demand equilibrium catch up before people realize it, and
5 then they flip the asset. They'll sell it to somebody else.
6 You have this high degree of asset turnover phenomenon
7 that's going through markets at this point.

8 I would say that, at this point, we're not seeing
9 any significant amount of investing attention about building
10 an asset without some sort of forward contracting or
11 certainty market structure. It's just too high of a risk
12 premium.

13 MR. SHANKER: Some other comments, but maybe
14 break it into two boxes. The first is, let's assume two
15 different market designs, and the ISO and FERC keep their
16 hands off and leave them alone. Then we have sort of the
17 status quo, boom-bust kind of cycle. We have the damp
18 volatility that comes with a downward sloping demand curve.
19 That's what the demand curve does, wide swings in price. It
20 serves as a damping mechanism to hold the prices into a
21 narrower range. Clearly, one reduces risk, perceived
22 volatility in that environment. If you can make the leap of
23 faith that you're going to leave the market design alone,
24 you're going to see a difference in the perceived risk.
25 Both will work, but one's going to be a lot more expensive.

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18895
DAV

61

1 There's another box that says do I trust that you
2 will leave this alone? I can see that for the next 10
3 years, or the next 20 years, even if you leave the status
4 quo alone, that will work. If you promise to actually let
5 the market go short and sit at deficiency prices for a long
6 enough period, that will work. I've got to say I don't
7 believe you'll do that; I don't believe PJM will do that.

8 Similarly, if you leave the demand curve
9 structure or the RPM structure in place for a long time,
10 that will work. I believe that has a higher chance of
11 staying in place because, inherently, it has the lower
12 volatility. But those are two different things. One is a
13 regulatory exposure risk, and one is a design risk. The
14 problem is a bad design also comes from a higher regulatory
15 exposure risk.

16 MR. BANDERA: Can we just jump back real quick to
17 the RMR issue, using it as a stop gap? That's a potential
18 stop gap until the transmission follows. Then we sort of
19 talked about the need for hedging and forward contracting to
20 get the investment.

21 Does it follow that having RMR contracts may sort
22 of discourage people from forward contracting, or is there a
23 relationship between people's forward contracting incentives
24 and the availability of RMR contracts? Is there any
25 relationship between those two?
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18895
DAV

62

1 MR. BOWRING: Let me just respond briefly. Take
2 the capacity market. If you effectively take units out of
3 the capacity market and pay them a side payment in RMR, that
4 affects the supply demand dynamics in the capacity market.
5 Clearly, it affects the price, and, therefore, it affects
6 incentives for new entry.

7 One of the things I tried to say at the beginning
8 is that RMR contracts are inherently short term, and they
9 inherently remove the incentive for new entry. They do the
10 opposite of what you want. As Harry was pointing out, and
11 others, it's also a method of price discriminating on behalf
12 of load. There is, in fact, nothing wrong. It sends an
13 appropriate price signal to have inframarginal rents in the
14 location where you need new investment.

15 MR. SHAW: I'd like to add to that in case
16 there's any doubt. RMR, we've talked about that being a
17 stop gap; it clearly is. What the effect is, it is we're,
18 in essence, paying inefficient units to stay on. That adds
19 to the cost, long term, as well as short term itself. Is it
20 necessary? Yes. But it should be clearly stop gap or last
21 resort.

22 MR. MARGOLIS: One of the things that's promoting
23 the RMRs is retirement decisions. The resource planning
24 process we're trying to forward-look 5 or 10 years. The
25 retirement decisions are very short-term notifications. Is
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18895
DAV

63

1 there a way to get around that disconnect?

2 MR. SHANKER: That's what Betsy was talking
3 about. That's the big issue. I proposed a design similar
4 to this like five years ago, the forward procurement. It
5 does two things. It can supply elasticity; that's sort of
6 nice, and it lets you sync up with the RTEP process so you
7 don't have to guess what units are going to be there in
8 terms of developing your transmission expansion plan.

9 Steve, I hope we'll talk later about how
10 difficult it is. It's not so simple to say anticipate a few
11 different types of retirement scenarios and double
12 transmission for that. It's tough. If can pin down which
13 units are out there four years from now, and I know de facto
14 who's not there by having done that, I know what
15 transmission needs to be built.

16 MR. MARGOLIS: But should there be longer term
17 obligations on the part of the generators in terms of
18 anticipating retirements or letting PJM know what
19 retirements there might be?

20 MS. MOLER: If I might comment, I think that this
21 overcommit thing -- I'm sorry to be a one-song pony, but
22 it's really an important part of the picture. It puts the
23 price out there. It lets generators decide whether they
24 want to come to the table or not. It puts the price signal
25 out there for potential developers. Right now, there are so
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18895
DAV

64

1 many developers that have been burned, substantial amounts
2 of money, that they're very, very weary of coming back in
3 the marketplace.

4 It is a tool that helps to sync up. You have to
5 have planning horizons for new generation transmission and
6 demand side resources. I agree with what Lynne said and
7 potentially new technology. But I'm not sure exactly what
8 technology she's talking about. But they need to be on at
9 least roughly comparable time frames, but not 90 days versus
10 5 years.

11 MR. CHIN: One additional comment on long-term
12 contracting. Both Greg and I noticed in our respective
13 coverage universes, electric utilities and energy merchants,
14 that in many cases companies in our respective sectors are
15 pretty cash-flow positive, Calpine notwithstanding. You
16 have a lot of IPPs out there that are actually generating
17 fairly healthy cash flows at this point, but they're not
18 looking at investing in generation because the
19 forward-contracting market is robust enough. There's no
20 clear regulatory signal about what market structure will be
21 in place, so instead they're diverting those cash flows to
22 shared buybacks and dividends. That's actually one major
23 theme we saw in 2004. If you want to divert those cash
24 flows back into generation reinvestment, or resource
25 investment, some type of forward-contracting mechanism that
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18895
DAV

65

1 is a little bit more certain would certainly help in that
2 regard.

3 MS. COCHRANE: I have a question for Betsy as far
4 as the four-year procurement. I do see that syncing up
5 with, for example, your Com Ed III, your retail auction
6 program? A number of the other utilities have said that the
7 problem with the four-year out is that it doesn't sync up
8 with other retail programs, such as in New Jersey. That's a
9 three year --

10 MS. MOLER: New Jersey is exclusively three-year
11 tranches. The one we have been working on, developing in
12 Illinois, has a variety of resources, including a five-year
13 portion of it. So we think the way to design a
14 retail -- it's actually wholesale, but retail
15 procurement -- is to minimize the price volatility. Have
16 some one-year blocks and some three-year blocks. And we do
17 have a five-year block in our coming auction, so it works.

18 MR. O'NEILL: Can I ask you a question about
19 these RMR contracts? I can agree with Patrick that
20 sometimes they may be necessary because you didn't get
21 everything right. But a lot of people that I've talked to
22 want to use them to suppress legitimate scarcity rent. When
23 there's a legitimate locational scarcity, they want to
24 invoke RMR contracts just to simply reduce the price.

25 The question I have is, if it's really just for
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18895
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66

1 those very serendipitous events, or events that you can't
2 plan for, that's one thing. But if it's moving to suppress
3 scarcity rents, that's another. And I'm wondering would you
4 use these tools simply to suppress the scarcity rents.

5 One of the issues that the large zones do is
6 essentially make the market look like it's bigger than it
7 is, and then you end up basically saying, oh, my gosh it
8 really wasn't that bid, and we're going to have to invoke a
9 bunch of RMR contracts, because the real units that should
10 have been in the market didn't clear the market.

11 I think if I'm right, we're somewhere coming up
12 on the 10th anniversary of RMR contracts. I don't know that
13 we're getting fewer of them or getting better. How do we
14 distinguish, how do we make sure, that when we invoke an RMR
15 contract that there's appropriate scarcity rents, not market
16 power, but appropriate scarcity rents?

17 MR. BOWRING: Let me take the first whack at
18 that. As you say, it may well be the case, and it is right
19 now the case in PJM, that you might need an RMR contract as
20 a band-aid; however, it's essential that you not make RMR
21 contract part of a design. I think they're being argued
22 for, in part, as an alternative to a rational capacity
23 market design. RMR contracts should absolutely not be part
24 of the design. Of course, they should be part of the
25 proverbial tool kit.

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18895
DAV

67

1 Clearly, PJM and its members have to do what's
2 necessary to maintain reliability. But to repeat, they
3 should not be part of a design because they will if part of
4 the design result in, as you indicated, price suppression.

5 MR. O'NEILL: If they're an accidental part of a
6 design, how do we make sure that we're not suppressing
7 scarcity rents with some kind of historical cost of service
8 calculation? That may be on a highly depreciated asset,
9 which gives them virtually nothing.

10 MR. BOWRING: That's very much a concern.

11 MR. O'NEILL: Do you do the calculations for your
12 RMR contracts?

13 MR. BOWRING: No.

14 MR. O'NEILL: Who does?

15 MR. BOWRING: The current situation in PJM, it's
16 filed by the owner of the retiring units.

17 MR. SHANKER: Dick, the whole predicate of the
18 forward procurement -- not the whole predicate. Half of the
19 predicate of the forward procurement is to minimize the need
20 to draw that line by making sure that it is a response to
21 locational scarcity. That's what you get.

22 People think that we're going to have a
23 balkanized system with lots of little locations, with very
24 high price differentials for capacity, like New York.
25 That's not what is happening here. By linking it to the

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18895
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68

1 RTEP process, what you're going to see is PJM identifies
2 -- let's make it simple. For the CTEL type scarcity,
3 violations in the subregion, it says, okay, we have to
4 build. We're going to increase deliverability into that
5 region, and doing a transmission we're going be moving up
6 the demand curve for a capacity, which will encourage the
7 resources that are there to stay there.

8 We're going to know four years out which
9 resources those are. They're going to be locked in. We're
10 going to see who builds and who doesn't. We're going to
11 look forward at the next step of the RTEP expansion and see
12 whether or not we still have those violations, and if we do,
13 we're going to direct more transmission planning.

14 I looked at it as their system with oscillation
15 between supply, transmission development and also the
16 bidding of transmission, which is allowed in this process,
17 that will move like that, that will give you sort of a three
18 to five-year window of price oscillation around the demand
19 curve that incent people to stay when you need them, and
20 also allows the time for the transmission to be built. It
21 will keep the system integrated in an aggregate sense. I
22 can't guarantee it will get rid of all the RMR, but it's
23 structured to eliminate the RMR. That's the intent of
24 what's going on here.

25 MR. O'NEILL: The point I was trying to make was,

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18895
DAV

69

1 or one of the points, is that if you use the RMR process to
2 overmitigate or oversuppress prices, it becomes a tool for
3 people to use that isn't what it was intended.

4 MR. SHANKER: That's the whole idea, is to not
5 let it become that tool. It should only be by exception,
6 either transmission outage, major unit failure --

7 MR. O'NEILL: But a lot of the opponents of this
8 process basically want to use the RMR process to both
9 suppress prices.

10 MR. SHANKER: It's clear if you price
11 discriminate, and then you go and you say, when we're short
12 we mandate long-term contracts on a cost basis and then
13 price discriminate the rest of the time, you've essentially
14 seized people's generation assets, and, of course, it's a
15 lower cost solution. That shouldn't come as a surprise.
16 You guys know that. We probably have a problem about just
17 and reasonable associated with that behavior, but, yes, this
18 is a form of price discrimination, and you don't want it.

19 MR. WEISHAAR: In terms of the RMRs, I'm a little
20 confused about the notion that RMRs are being used to
21 suppress prices. The generation owners seek the reliability
22 determination. The generation owners determine their cost
23 filings. The generation owners make the filings with FERC.
24 It would seem counterintuitive for a generation owner to see
25 an RMR in order to suppress prices that would benefit the

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18895
DAV

70

1 generation owner.

2 I mean, I perceive RMRs as kind of corrections to
3 flaws of gaps in information flows. It's a process where
4 RTEP, perhaps, didn't take into account soon enough problems
5 that eventually arise in particular locations. RMRs have a
6 lot of context, fixes that recognize that transmission has
7 been announced, is being planned, will be constructed. But
8 for the two, three, or even four or five-year gap, between
9 status quo and transmission construction, certain generation
10 units are needed to come on line.

11 MR. O'NEILL: Would you argue that during that
12 time it suppresses prices?

13 MR. WEISHAAR: I think because you're paying cost
14 of service instead of allowing prices to skyrocket, it
15 probably is. The question is, if a transmission fix is
16 coming in, in any event, in order to solve the problem, what
17 price signals would you want to send?

18 MR. SHANKER: Just to clarify, the personal price
19 isn't for the guy getting the RMR contract; it's for
20 everybody else. You're expanding this offer, this supply,
21 in the market and depressing the clearing price for everyone
22 else. We're missing the point here.

23 MS. COCHRANE: I think the Commission has had
24 day-long conferences on RMR.

25 (Laughter)

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18895
DAV

71

1 MR. TIGER: If I could follow up on transmission,
2 people have talked a lot about transmission being on an
3 equal footing with generation in regard to this four-year
4 RPM proposal. Given Ms. Moler's eloquent description of
5 some of the difficulties of getting transmission, built, I
6 wonder if people could talk specifically about who they
7 think is going to step up to the plate and how it's going to
8 be operationalized that transmission would actually be an
9 equal solution to generation; also, given the success this
10 far of RTEP that we've seen --

11 MR. McCULLAR: I'd be glad to take a swing at it.
12 What you're really referring to is merchant transmission
13 project coming forward.

14 MR. TIGER: I guess I'd like to have people
15 explain how they think that people who bid in a transmission
16 project feel that they'll be able to get it done within four
17 years such that they aren't themselves short when it doesn't
18 materialize, if, in fact, our problems in bringing
19 transmission to fruition --

20 MR. McCULLAR: I think there are some significant
21 barriers to entry in the way the process for a merchant
22 transmission bidding occurs to day. We have a very
23 well-developed and robust queue process for generation. You
24 come in, and you get the ISA done. You get the impact study
25 does, the feasibility, your costs, all the way through.

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18895
DAV

72

1 It's not as clear for transmission. The second
2 part is that you're not just dealing with one person in the
3 RTO like you should. You're actually dealing with two.
4 You're dealing with the RTO and the legacy transmission
5 owner, whose facilities you will be building over, building
6 around, building through. It's a very marshy, weedy area to
7 try to work in. I think that's demonstrated by to date, a
8 few merchant transmission projects that have come forward,
9 and been put into the cue, and have been unsuccessful.
10 They've never come to fruition. I think that's a big
11 problem.

12 MR. SHAW: I'd like to comment. Hopefully, you
13 aren't referring to the peninsula when you said marshy and
14 weedy.

15 (Laughter)

16 MR. McCULLAR: Only the western part.

17 MR. SHAW: We're building a transmission line,
18 basically down the length of Delaware, as we speak, and we
19 are in the final stages of completing one down the southeast
20 coast of New Jersey. The decisions that led to that were
21 very much like one might imagine. You look at what the
22 alternatives are, and you file with PJM. Eventually, it
23 gets into the regional transmission expansion plan. Those
24 are in one case 90 miles, in one case 70 miles building
25 transmission. I've been responsible for building power
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18895
DAV

73

1 plants. It's not getting any easier and it is very
2 difficult.

3 So having a mechanism that links up the
4 generation planning with the transmission, to the extent
5 possible, and we're not perfect, is extremely important.
6 I'd like to actually, since my mike's open, address the
7 question that Anna asked earlier about New Jersey because we
8 serve several thousand megawatts in New Jersey. We also,
9 through an affiliate, participate in the wholesale market.
10 Yes, it is a three-year auction and that has some issues
11 with it. The comments Betsy made I think are the right way
12 to go, but it is what it is currently. I can tell you our
13 affiliate -- I used to run it -- looks at the RPM and says
14 it will add certainty. Therefore, what I bid will likely be
15 lower than it would otherwise would be if that certainty is
16 there. So that's how that helps.

17 MS. KIESLING: Sebastian's question is one of the
18 reasons why I phrased what I did the way I did about the
19 transmission being on an equal footing. For me that's a
20 really upper crucial issue. I'm not down in the trenches,
21 but at least at a conceptual level, in my written remarks
22 I've suggested one way you can deal with this in the market
23 design.

24 Ideally, what you might want to do is instead of
25 just having potential capacity suppliers bidding off the
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18895
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1 curves, that you make the offer basically a two-couple; I'm
2 going to build the capacity to deliver an additional
3 megawatt at this price and in this amount of time, instead
4 of just saying a price and a time. Then, essentially, the
5 length of time becomes endogenous and you can keep a more
6 liquid market instead of we're going to have -- say we're
7 having a one-year market, a two-year market, a four-year
8 market, et cetera. It makes for a more complicated market
9 design, but it may help you have more liquidity an enable
10 that equal footing.

11 MR. SHANKER: Again, remember there's two boxes
12 here. One box is the merchant or voluntary bid of the
13 transmission, and at a fixed time frame it may be difficult.
14 And some sort of auction structure like we were talking
15 about may actually be something we can consider. But the
16 discussion that everybody else has been talking about, about
17 syncing things up, those are based on the RTEP-directed
18 investments associated with reliability violations that PJM
19 identifies, and is able to identify based on projected load
20 growth, and, in this case, a known pattern of generation.
21 Those are directed to the transmission owners. They're not
22 volitional in that sense. They're part of the reliability-
23 based investments here. They're not merchant.

24 I'm sure they have all the scheduling things.
25 Steve is able to talk more about that than I can, but those
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18895
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75

1 are not the sort of typical, at-risk merchant structures
2 here. Those are going to rate-based activities that are
3 being designated based on specific reliability violations.
4 They are designed explicitly to fix the type of problems
5 that would otherwise necessitate the RMR requirements in the
6 presence of unknown or uncertain retirements of units.

7 MR. BANDERA: Would the RPM have avoided the
8 current need for the RMRs that exist today in PJM? So when
9 we look at the situation that exists today, where some New
10 Jersey units may be getting these RMR contracts, would RMP
11 have taken care of that in advance?

12 MR. BOWRING: Obviously, we can't know that, but
13 that's the intent of the design. The exact intent of the
14 design is to have a long-term, forward signal out there so
15 when additional capacity is needed in an area, there will be
16 a signal for new investment. We won't get to the situation
17 where we have incipient retirements and need RMRs.

18 MR. SHANKER: Four years ago, those units hadn't
19 cleared. Ask Steve if that would have been sufficient time
20 to do the improvements that are coming on in three or four
21 years. I mean, it's that time frame, right? That's my
22 understanding from what they've told us in the stakeholder
23 process. We're going to recover from that in three or four
24 years.

25 So four years ago, those units hadn't cleared,

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18895
DAV

76

1 which, presumably, would be the basis of them offering, and
2 then not getting enough money, and then retiring, then we
3 would have had the three or four-year time frame to build
4 the transmission, which is what we're doing now; that it's
5 in that same window, and you can again say whether it's five
6 years, or three years, or whatever.

7 MS. COCHRANE: I'd hope to end this panel around
8 11:00. I just wanted to take a quick check of the table to
9 my right to see if there are any commissioners or Commission
10 staff behind me that would like to ask any questions.

11 (No response)

12 MS. COCHRANE: If not, I'm sure we'll continue.
13 I was just wondering if you or Commissioner Kelly have any
14 questions, or the state commissioners?

15 COMMISSIONER BROWNELL: I know we're going to
16 talk about transmission this afternoon, but a thread that I
17 heard here consistently is that, in fact, the transmission,
18 not the planning process, is, in fact, fundamentally flawed
19 but intimately related to the success of the market design.
20 I'll be asking to get a list of the merchant projects that I
21 think we've asked for but have been languishing, and we need
22 to understand that because I think there were some
23 enhancements.

24 A company -- I don't know who they are -- called
25 HP Trading submitted some comments in another docket about a

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18895
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77

1 proposal they have on the Beddington Black Oak constraint
2 that would increase capacity by 1400 megawatts. I need to
3 understand why those aren't happening, because I think
4 unless we address some of those issues, we'll be back at the
5 table wondering why things aren't working.

6 I think there have been some other suggestions
7 that have been submitted. I think that we really need to
8 think about that. We don't have another year to do that. I
9 think we need to get aggressive. So I would ask this panel
10 and others to send in, in addition to their comments on the
11 capacity market, very, very specific fixes that they would
12 do to the RTEP process to make sure that we're addressing
13 all these issues. Do you have any questions?

14 COMMISSIONER KELLY: No.

15 MS. COCHRANE: Just to clarify Nora's reference,
16 it was post-conference comments of HP Energy Resources in
17 the Coal-Fired Resources proceedings, 88053, if anyone wants
18 to look at that.

19 David?

20 MR. KATHAN: While I have Professor Kiesling up
21 here, I wanted to ask a question. I've heard this also in
22 some of the discussions about the use of experimental
23 economics and wanting to look at doing experiments on this.
24 I guess the question I have is, how do you see these type of
25 experiments would support he discussions, or how long would
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18895
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1 it take to do this; what's your thoughts in terms of who
2 would be involved; those types of questions.

3 MS. KIESLING: That's a really good question.
4 Actually, in late April, PJM hosted a meeting where Tim
5 Mount and I, who both do experiments, and some other
6 economists, including Ben Hobbs, met at PJM. We talked
7 about how we could take Ben's model and the RPM proposal and
8 potentially do some experimental testing. We came up with a
9 list of about four or five different hypotheses we could
10 test and ways we could structure it, largely revolving
11 around testing the shape of this artificial demand curve.
12 We're starting from sort of square one with the demand
13 curve.

14 As much as I complain about the artificial demand
15 curve, I hold my nose and say, okay, yes, we have the
16 artificial demand curve, but let's kick the tires and see if
17 the shape tested in Ben's simulation really represents the
18 way you might expect load-serving entities to behave if this
19 were a true double-sided market, and LSEs could bid in on
20 the demand side, in the presence of contingencies or no
21 contingencies, in the presence of market mitigation or no
22 mitigation. Usually we do sort of two-part tests like that.

23 The time frame, the types of things we've been
24 discussing tend to take from six months to a year. So
25 usually in the time frames that we tend to operate in, in
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18895
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79

1 this space, when you would like to have things pass
2 yesterday, that's sort of long lead time to do experiment
3 often precludes there being necessarily something that folks
4 want to pursue.

5 But I do encourage it, for the very real reason
6 that this is a very complex, very sophisticated network of
7 machines plus humans. It's a physical, plus human,
8 integrated, dare I say, organic network, and just doing
9 computer simulations, while that's a huge part of informing
10 us about how the system is going to operate doesn't tell us
11 anything about how real live humans, who are motivated by
12 profit incentives, are going to operate in conjunction with
13 that system.

14 So that's the real value proposition for doing
15 the experiments. The time frame is in the sort of six
16 months to a year. You said also, who would participate?
17 Generally, our subjects are students. Occasionally, people
18 will dismiss experimental economics by saying that, you're
19 just paying sort of petty change. But we always calibrate
20 the payments so they are at least the subjects' opportunity
21 costs. The average pay off is generally something along the
22 lines of \$10 to \$15 an hour, which is pretty equivalent to
23 your opportunity costs if you're a 21 year old.

24 The beautiful thing about experimental economics
25 is so much decision-making and so much of our rationality is
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18895
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80

1 so deeply embedded in our subconscious, and you can't
2 program a computer to access that. When you put people in
3 an environment, and you tell them they get to walk out with
4 whatever they earn, they're going to get in there and
5 scramble for every penny. They'll find flaws you didn't
6 know were there. They'll find strategies you couldn't have
7 predicted, and that's the true benefit of the methodology.

8 MR. KATHAN: From the meeting, if there were any
9 discussions or any proposals, we'd like to see that.

10 MS. KIESLING: I didn't put that in my written
11 remarks, but I will do.

12 MR. SILLIN: Question for Brian. Brian, you
13 indicated that there are businesses, firms, that you do say
14 attract returns earlier in your comments. Could you just
15 summarize what kind of technologies those firms are
16 strongest in terms of the type of generation or capacity.
17 They appear to be providing the strongest returns --

18 MR. CHIN: When I referred to there are investors
19 willing to look at generation, they are willing to look at
20 generation assets that are transacting at value well below
21 replacement costs. It's not as though they've identified
22 new technologies that appear to be promising; rather,
23 they're looking at older generation assets that have been
24 significantly devalued by the marketplace.

25 For example, it's fairly common to see

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18895
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81

1 transaction values at 40 to 30 percent below replacement
2 costs. We have noticed large transactions -- for example,
3 Duke Energy recently sold a significant portion of their
4 southeast generating facilities for about a dollar because
5 they were tax-loss benefits out of a sale. When we look at
6 distressed asset investors, they'll come and they calculate
7 their return on capital because they'll be investing money
8 in an asset that they anticipate will come back into the
9 money at some point. Through a supply and demand
10 equilibrium, it comes back into balance.

11 That's what I meant by my comment. We do see
12 other technologies that come through the pipeline like IGCCs
13 and other types of generation like pebble-bed nuclear type
14 reactions that are getting bandied about in the space. But
15 in terms of significant transactions, no. It's primarily
16 generation assets that already exists that are trading at
17 low values.

18 MR. SILLIN: A capacity construct, along the
19 lines that are being discussed, how would that fit in, in
20 terms of providing incentives for those kinds of
21 technologies? Would it be a significant part of the
22 incentive for investors to look t that technology, or are
23 there other factors that are more significant?

24 MR. CHIN: I think the factors that primarily
25 determine investment in this space are looking at supply and
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18895
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82

1 demand relationships, and where the projected power price
2 spikes are most likely to occur are capacity market
3 structure; basically set incentive a little bit richer, but
4 in terms of directing a capacity market structure to favor
5 certain types of technologies over another, I think that
6 would depend on the details of the capacity market
7 structure. Certainly, if you have some sort of quit-start
8 mechanism, incentive mechanism, some sort of generation fuel
9 provision that favors that technology, obviously, the
10 investment response would be commensurate. But right now,
11 by and large, the vast majority of the investment incentive
12 appears to be the anticipation of some tightness off of what
13 is right now a very distressed asset valuation scenario.

14 MS. COCHRANE: I think we have one last question
15 from Harry.

16 MR. SINGH: We heard a lot about why RMR
17 contracts might be good for existing generation, but they
18 don't send any price signals for new investment because they
19 don't give you a long-term contract.

20 Brian, you emphasized long-term contracting as
21 well. Do you have any thoughts on how the proposal that is
22 before us would do in terms of long-term contracting, and,
23 specifically, the issue of if you do it four years out,
24 maybe it gives a bigger piece, with PJM being the POLR;
25 versus if you do it one year, maybe LSEs buy more. I don't
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18895
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83

1 know if this is the type of thing that experiments can
2 answer. My guess is it would be physical because it's a
3 long-term system. If you have any thoughts on that?

4 MR. CHIN: Sure. With regard to RMR contracts, I
5 have made earlier comments in previous conferences that in
6 some instances, RMR contracts can actually serve an
7 immediate, short-term need. If you're looking at a company
8 that has signed an RMR contract for a few years, and the
9 contract provisions are public, and you can sense or model
10 out what the profitability of the contract is, that's
11 helpful. But that's only on a short-term basis. There's a
12 longer term structural risk in that. You don't know when
13 regulators will step in to mandate the signing of an RMR
14 contract. You can't tell when that will happen and over
15 what frequency period. As a result, it's actually an
16 investment disincentive in the long run.

17 I think I'm referring back to that
18 regulatory risk that Mr. Shanker was referring to earlier
19 with regard to the proposal before us when we're looking at
20 the four-year auction process. From our standpoint, a
21 four-year auction process helps identify what are the
22 modeling numbers that we can use to put into a model, even
23 if a company doesn't give us a series of financial guidance
24 metrics.

25 A similar scenario would be if you look at the
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18895
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84

1 New Jersey BGS auction. That has a rolling-forward,
2 three-year auction result. We typically use those auction
3 results as numbers. If we don't have anything else, we'll
4 use those numbers as part of our financial forecast to give
5 us some semblance of where the trajectory is going.
6 Similarly, when we look at the forward-energy markets, like
7 Professor Kiesling said, as imperfect as they are and as
8 illiquid as they are, in the absence of any other pricing
9 information, we'll take those forward prices as they are and
10 pump those into our models.

11 So the capacity market proposal that has a four-
12 year forward auction gives some level of certainty over
13 that, and in my opinion, the further out you have that
14 trajectory, the better off you are in terms of having some
15 sort of certainty that you can finance, and eventually
16 invest in. So longer is preferable, but along the spectrum,
17 a one-year auction is better than a one-month auction
18 forward, for example.

19 MS. KIESLING: A quick comment, Harry. You will
20 be pleased to know that this bodes well for our future. I
21 have an undergraduate who is doing his senior honors thesis
22 next year, running experiments on RMR questions
23 specifically. He can come up with the funding to pay the
24 subjects.

25 (Laughter)

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18895
DAV

85

1 MS. KIESLING: I hadn't suggested to him that he
2 touch on the regulatory risk issue. He's touching on a lot
3 of the other topics we discussed today, though, so maybe I
4 will.

5 MR. BOWRING: Harry, can I just respond real
6 quickly as well to your question? The way I see the RMR
7 construct is, is using a stable market design in place of
8 long-term contracts, and attempting to create a set of
9 expectations among investors, clearly, it's not a long-term
10 contract; it is a forward contract for one year. But the
11 idea is, again, to create a stable market design, which will
12 create a corresponding set of expectations about future
13 prices, and, again, it also emphasizes the importance of, as
14 I think you were indicating, underlying bilateral contracts,
15 which respond to those forward prices.

16 MR. SINGH: I didn't mean to focus so much on
17 RMRs. I was concerned more about how the proposal is going
18 to do with long-term contracts. I think Brian's comments on
19 the BGS auction were useful because we had this debate
20 looking into procurement processes, the kind that we see in
21 California, for example, long-term RFPs or something more
22 transparent, even if it's not long term. And you're saying
23 that it is useful.

24 MR. SHANKER: One of the things, Harry, is that
25 it's the background against which people will be contracting
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18895
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86

1 for a long time. There's still the case that proven
2 participants in the market, particularly those that have
3 long-term load obligations, will enter into long-term hedges
4 if they're reasonable about it. The question is, is it more
5 likely to encourage somebody to hedge their risk in a market
6 where there is some volatility, but the volatility is
7 possibly predictable and there's a reasonable forward curve
8 to work against, or is it more likely will hedge where
9 there's huge volatility and it's unknown?

10 You hear arguments on both sides. This is
11 actually a good area for experimental economics because you
12 can support -- it has to do with the risk aversion functions
13 for the individuals that are involved. Some people say they
14 are scared to death with high volatility and they'll hedge
15 more. Other people say, I'm terrified by the cost of the
16 errors, and the existence of long-term, forward prices makes
17 it a more stable environment. For me to be able to say yes,
18 so I'm off a little one way or the other, and I'll enter
19 into a 10-year contract. It's not clear, but for the
20 investment side of it, is it clear I think.

21 MS. COCHRANE: Thank you very much for a very
22 informative panel discussion. We'll take a 10-minute break,
23 and we'll start at the next panel, talking about the
24 specifics of the alternatives.

25 (Recess)

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18895
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87

1 MS. COCHRANE: If we can try to get started,
2 please. This next panel is about the alternative capacity
3 markets, models that are currently on the table.
4 Commissioner Brownell is not here, but she'll be back, and
5 she said to go ahead and start without her.

6 The first panelist is Andy Ott with PJM, to talk
7 about an alternative that we've already heard quite a bit
8 about this morning, but, hopefully, will present some more
9 specifics on PJM's reliability pricing model. Thank you,
10 Andy.

11 MR. OTT: Good morning. Thanks for the chance to
12 talk in front of you today. Essentially, the long-term
13 investment infrastructure issues in the industry need to be
14 resolved, obviously. One of the missing pieces, if you
15 will, to competitive market evolution has been, are we
16 seeing long-term sustained infrastructure investment? I
17 submit the answer is, we haven't seen it yet. The capacity
18 market design needs to focus on long-term infrastructure
19 investment issues. Notice I didn't say generation, I didn't
20 say transmission; I said infrastructure investment, meaning
21 all of it, okay?

22 The PJM board recognizes that the
23 transmission planning process we have today needs to be
24 revised to focus more on long term and to focus more on the
25 needs of the competitive market as opposed to only on
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18895
DAV

88

1 reliability. We have recognized that, and have a
2 stakeholder process to get that moving as quickly as
3 possible; however, transmission expansion alone isn't going
4 to solve the problem. You need an integrated solution that
5 integrates integration demand response and transmission.
6 Essentially, that's what we have with RPM.

7 One of the questions that came up earlier was the
8 fact that RPM does allow transmission to compete directly in
9 the auction four years out with the generation and demand
10 response. Is that meaningful? I submit that it is
11 meaningful, in a couple of different ways.

12 As you look at transmission expansion, one of the
13 problems we've had today, with what I'll call
14 non-reliability-based transmission expansion, is that there
15 is no competitive investment model. There's no way to
16 essentially get in there and say, what are the dollars I'm
17 going to get on a forward basis. If you actually look at
18 transmission building when you're putting in
19 transformers -- 150 KV, 230 KV -- all that can be done five
20 years or sooner. It's the stuff that's the 500 KVs. The
21 long-haul 500 KVs is the stuff that takes 10 years or
22 whatever to build.

23 The point is there's substantial transmission
24 infrastructure that can be built on that kind of time frame.
25 The fact that the RPM has incremental auctions where you can
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18895
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89

1 bid a position on a forward basis, and you can adjust that
2 position each year as you get closer allows, again, that
3 same kind of dynamic, if you will, for somebody to take and
4 say I will build. But if they run into problems, they can
5 get an alternative solution to jump in. That kind of
6 dynamic, actually, is a meaningful, competitive transmission
7 investment model, which is what we don't have today.

8 If we flip over to, essentially, the capacity
9 market design efforts we had PJM, essentially we've talked
10 about, as you've heard, capacity for a while in PJM. The
11 redesign efforts have included both a regional -- PJM had
12 done the Northeast RTO capacity stuff, and that didn't seem
13 to get us to where we needed to go, so we have other
14 stakeholder processes that have occurred.

15 The initial reliability pricing model design was
16 put out in 2004 in June. We discussed it and modified it
17 through the stakeholder process for about a nine-month
18 period. One of the most striking issues was that there are
19 a lot of dollar impacts. It's well-documented that this is
20 a big dollar ticket item.

21 So it's not unrealistic. You have debate, what
22 I'd call fundamental disagreements. We had over 100
23 meetings to talk about this. We made modifications as we
24 went forward. I attached those to my documentation. One of
25 those documentations was actually substantive. We actually
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18895
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90

1 added the transmission investment participation. Again,
2 there are different stakeholder views, and consensus
3 couldn't be achieved. It's obvious to you, probably today
4 from the first model, that there are substantive
5 disagreements. That's why we're here today.

6 I switch over to the fundamental design elements
7 of RPM. Again, the overall goal is to align pricing paid
8 for capacity with overall system reliability requirements.
9 Today we don't have that. As you know, we don't have that.
10 As you know, we don't have the locational components, which
11 are a fundamental reliability requirement. There is one
12 I'll call a devaluation of capacity on a forward basis
13 because of the short-term nature of the current market. So,
14 again, the design features of RPM were developed to address
15 those fundamental issues.

16 As I'll go through what I'll call the three key
17 elements of RPM. We have the locational capacity pricing.
18 Again, that was necessary to ensure capacity pricing is
19 consistent with local reliability, the granularity of the
20 locational elements. Essentially, we were talking on the
21 locational pricing debate, I was sitting here probably at
22 least before some of you. I was talking about should we
23 have a single clearing pricing; should we have locational
24 pricing? What we learned in that debate and what we learned
25 in the reality of the market is that implementation is that
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18895
DAV

91

1 pricing has to be consistent with the physical reality in
2 order to make sure that the pricing doesn't have what I'll
3 call fundamental flaws.

4 One of the proposals we'll hear about to date
5 does not put locational requirement, based on the actual
6 engineering analysis, in the RTEP. It seeks to have much
7 larger zones in order to get a better bilateral market.
8 Again, I submit to you we lived through that debate before,
9 and it didn't work. Essentially, we had to get back to the
10 reality of the system pushing the pricing to be as granular
11 as it needs to be, based on the engineering.

12 Again, the concept of having a locational signal
13 puts the transparent price signal out there that directly
14 competes with an RMR contract. So, essentially, if you have
15 no locational signal, you have a hidden RMR contract, and
16 new entry won't see that and compete with it to get rid of
17 what I'll call the old-dog unit that you really are paying
18 to keep around. So it's fundamental that you have that
19 feature as granular as it needs to be to meet system
20 reliability requirements.

21 There was a transition mechanism to try to help
22 lessen the burden of moving into a locational requirement
23 right away, to try to acknowledge that existing contracts
24 are there, to try to make sure we didn't unwind existing
25 contracts as we move into location.

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18895
DAV

92

1 We move to variable resource requirements.
2 Essentially, the variable resource requirements I'll try to
3 spend less time on because we hear a lot more about that
4 today from others, but it does resolve the capacity price
5 volatility issues that you heard about earlier and does deal
6 with market structure issues. It puts the implicit price
7 cap on the market, which essentially is geared toward new
8 entry, so it does allow the market to be better structured.
9 Again, the direct valuation of the reliability benefits of
10 additional reserves are contained within that variable
11 resource requirement.

12 Next, I turn to the four-year forward
13 commitment, which is probably differentiated between what
14 this model is and what the other Northeast models have done.
15 Again, the concept here is it is a very critical element,
16 essentially, to have the longer-term forward commitment.

17 You heard today, earlier, about the competition
18 by new entry; again, the meaningful participation in new
19 transmission upgrades. You can't have that one month out.
20 If you have an auction one month out, you really can't see
21 that direct competition, and by direct, it's what I'll call
22 competitive investment model. If you're looking at the
23 design of the RPM, where it really is trying to make sure
24 that the money you spend on reliability is money well spent,
25 that's really the key.

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18895
DAV

93

1 The long-term forward commitment, again, provides
2 a strong incentive for generation to respond to capacity
3 shortages because you actually see the price out there, and
4 you see what's coming up. The price is more stable. One of
5 the phenomena we see in the industry is there's a lot of
6 issues related to environmental impacts on generation. A
7 four-year forward commitment allows you to see that coming,
8 and compared directly what the alternatives would be, rather
9 than wait until the last minute when the reg kicks in, and
10 you're scrambling trying to figure out what to do.

11 If you look at the transparent forward-pricing
12 tool -- again, transmission demand response and generation
13 solutions -- to directly compete, again, we go back to the
14 business model. I've heard folks say that the RPM will
15 create problems for demand response. I submit again to you
16 that the types of demand response we have today are driven
17 by the market structure. If we add a market structure that
18 looks into a longer term, capacity product for demand
19 response, you'll get new types of technology and new types
20 of demand response offering in. There's no way to date to
21 put that kind of investment out because there's no
22 investment model for it. But putting out a forward price
23 and allowing direct competition of that demand response with
24 generation will provide a new opportunity. It won't
25 necessarily change the existing opportunities, but it will
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18895
DAV

94

1 add a new one.

2 The new entry, again, has been talked about a
3 lot, so I'll skip over that. But I do want to talk about
4 the bilateral market. Folks have postulated, again, that if
5 we do a four-year forward, it will destroy the bilateral
6 markets. I sat again through the LMP debate. I heard, as
7 we go from a single clearing-price market to a full nodal
8 market, it will destroy, essentially, bilateral competition
9 as we know it. We all, sitting here five years later, saw
10 that did not occur. What happened was the bilateral
11 contracts under that energy market had to switch from the
12 seller's choice to bilateral markets, incented more around
13 the hubs or some other construct.

14 I submit to you, a longer term market in the RPM
15 will not destroy bilaterals, but it will change their
16 fundamental nature. It will make them become longer term.
17 Something that is not existing today is the discipline on
18 the load-serving entities to make sure they have enough
19 resources into the future to preserve reliability.
20 Providing the longer-term forward commitment will require,
21 essentially, for hedging as we talked about. As you had
22 heard in the first panel, the hedging requirement will
23 suddenly look out further, and we'll get what we're looking
24 for, which is longer term bilaterals for reliability into
25 the future.

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18895
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1 Again, we need to accept the responsibility for
2 the long-term reliability of the system. The way to do that
3 is to create a longer-term forward commitment, and, again,
4 to embrace the adaptations of the bilateral contracts that
5 must happen with it.

6 Again, PJM recognizes that the capacity market
7 alone cannot resolve infrastructure issues. Implementing a
8 longer-term planning process, adapting the planning process
9 to look at what the needs of the competitive market are, in
10 addition to adjust reliability, is critical. Implementing a
11 permanent demand-response solution is critical. PJM is well
12 along in the stakeholder process. In fact, it's to come
13 before the Commission before the end of this year. An
14 integrated demand-response solution, essentially, will make
15 our existing demand response permanent. It will add a
16 forward-energy reserve product, which, again, is the first
17 opportunity, if you will, that demand response has for a
18 longer-term energy market, which is going to be critical to
19 its development. It adds in demand-response capability to
20 participate in ancillary services, which, again, gathers the
21 revenue stream that they can participate more broadly, if
22 you will, on an equal footing with generation. All that has
23 to be done. But, again, demand response and transmission
24 alone is not going to solve the problem. We still need to
25 fix the fundamental issues we have with capacity.

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18895
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1 Again, the last component of the demand response
2 is to allow its full participation in capacity. Today it
3 doesn't really actually have that. It actually, under the
4 RPM, has full participation in the capacity construct. The
5 PJM analysis has indicated that the RPM method produces a
6 consumer benefit. You'll hear about that later today. The
7 consumer benefits, as they talked about in the first panel,
8 are related to the fact that you would substantially reduce
9 forward investment risks, so the cost of capital goes down.

10 The stakeholder process that we have gone through
11 in PJM has resulted in significant progress on debate of the
12 issues. If we're sitting here from last year to this year,
13 we're actually honing down towards the real issues in
14 capacity market design. These have, at times, highlighted
15 design flaws, and the debates have centered around ways to
16 fix that.

17 The need for change is acknowledged. Everyone I
18 talk to acknowledges the existing capacity market must
19 change. We need to get on with the change, though, because
20 the existing markets that we have today are sort of
21 paralyzed with the rules not being defined into the future,
22 what would probably be worse than just staying with the
23 current construct at this point. So we really need to move
24 forward and resolve the issue. Thank you.

25 MS. COCHRANE: Thanks, Andy.

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18895
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97

1 Our next presenter is Ed Tatum, with Old Dominion
2 Electric Cooperative, presenting a proposal of a coalition
3 of companies; an association, it's my understanding, the
4 Enhanced Transmission and Capacity Construct, or EITCC.

5 MR. TATUM: Thank you so much. We're talking
6 about incremental change here today. Actually, I've come
7 here today to talk about RMR contracts, and I'll try to
8 address that issue once and for all.

9 (Laughter)

10 MR. TATUM: I'm Ed Tatum with Old Dominion. As
11 Anna said, I am representing a proposal from a number of
12 different folks on a handout that's going around the room.
13 There's a list of about 50 different organizations from the
14 PJM Public Power Coalition; the PJM Industrial Customer
15 Coalition; as well as some of our public advocates who are
16 supporting this proposal over other constructs that are
17 currently on the table. I want to say that because we are
18 the consumers, and I've heard a few comments from the first
19 panel that we're looking to benefit these consumers, and we
20 are the consumers. We're very concerned. We want to make
21 sure these benefits truly do apply.

22 I liked the opening comments we had today. WE
23 are not in a perfect world; we do not have a perfect market.
24 But where we are right now is a world that's evolving. We
25 are trying to get into a market world, and moving from
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18895
DAV

98

1 vertically integrated monopolists into a competitive mode.
2 We have economically rational behavior that we're seeing
3 from folks; contracts, as Joe Bowring said, versus
4 locational capacity needs, so these need to be addressed.

5 The alternative proposal I'm going to present
6 here does not ignore capacity. I want to be very clear
7 about that. It does have a capacity construct. It does not
8 use RMR contracts in any way, inconsistent with the
9 discussion that was had here in this first panel. It's a
10 last resort transition.

11 We expect that under this proposal, RMRs would be
12 less likely. We do need to address planning. We do need to
13 address transmission construction. Simply because it's hard
14 to do doesn't mean that we shouldn't try to do it, roll up
15 our sleeves, and make it happen.

16 The other comment I'd like to make as far as a
17 public power entity, we are attempting to bring solutions
18 here that we feel will indeed work. We have engineers,
19 lawyers, economists, who are fairly patient with me as they
20 try to help me understand exactly what they're talking about
21 as we go through these various designs.

22 The EITCC proposal, if you will, is
23 philosophically a bit different approach. We are focusing
24 on resource and infrastructure adequacy rather than revenue
25 adequacy for a particular set of assets, and we want to

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18895
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99

1 provide the infrastructure to get the right resources built
2 in the right place, at the right time. There's a capacity
3 component for resource adequacy and trying to maintain
4 market processes where resources and loads can rationally
5 transact.

6 Transmission. Again, we've talked about the need
7 for longer lead times, the need to facilitate appropriate
8 cost recovery, the need to enhance local planning as well as
9 regional planning.

10 There are some common aspects that our proposal
11 has with the reliability pricing model. It has a system, as
12 well as a local adequacy focus. We do agree that local
13 capacity needs to be addressed. It's reliability based. It
14 provides improved certainty -- in other words, reduced risk
15 over the current construct, which does need to be modified.
16 Those features I just listed will incent new generation; the
17 locational aspect and the market aspect will provide
18 additional revenue to what we might think of as at-risk
19 generation; and we're sure it integrates very nicely with
20 transmission and demand response.

21 Differences from RPM include that this is a
22 market-oriented approach. We're trying attempt to match
23 willing buyers and sellers. We want to enable the market,
24 not create administrative price. We want to promote
25 long-term, bilateral contracts.

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18895
DAV

100

1 We have a situation where the load-serving entity
2 is responsible for procuring their capacity requirements. I
3 think that's very important. We are the load-serving entity
4 that's going to be in control of our destiny. We want to
5 meet our obligations.

6 We feel it has a straightforward integration with
7 demand-side response given the features of the various
8 auctions and the various times. It generates forward prices
9 that can be used to inform the market. These are going to e
10 long-term prices, four years out or possibly even more if
11 you'd like. We'd be happy to talk about it. That would
12 inform folks and enable them to trade around that. It does
13 not attempt to administrate or provide revenue adequacy for
14 a particular asset group. It does, however, provide
15 comprehensive, market-oriented, long-term framework for the
16 right mix of resources. That includes in our mind demand
17 response transmission and generation. It recognizes the
18 appropriate lead time for each type of resource and it does
19 provide long-term capacity requirement that will allow load
20 to creatively meet its obligations and honor its
21 responsibilities.

22 EITCC. We viewed it as an incremental change to
23 the current construct. We have system and local
24 requirements. The system, installed reserve margin, and
25 local obligations are both identified three years ahead of
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18895
DAV

101

1 time, based upon engineering studies and planning analyses.
2 The load-serving entity's obligation is increased from one
3 that is daily to a full year. There's deficiency penalty
4 removing from a penalty that would apply only an interval to
5 an annual basis. The penalty maintains the current capacity
6 deficiency rate, which we believe is a premium above the net
7 cost of new entry. Visa items help provide information.
8 The deficiency penalty helps provide inspiration for folks
9 to perform and meet their obligations.

10 Under the options, there are many. There's a
11 multiyear, voluntary auction that would be run on a
12 quarterly basis four years out. It would give a long-term
13 price signal that folks can trade around. There will be a
14 final clearing auction that would be held two months before
15 the actual planning year in case people hadn't met their
16 obligations, and people would trade around that. Then right
17 before the planning year there would be other what we think
18 have interval options to allow people to trade part-year
19 positions and mix and match various resources to come up
20 with a full total year planning year obligation.

21 Transmission attributes include expansion of a
22 planning horizon of what we're supposed to be doing five
23 years to either 7 to 10 years, and we're happy to talk to
24 PJM and the transmission owners about how to do that. I'd
25 like to retain five years for the short time frame

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18895
DAV

102

1 requirements and proactively accrue upgrades based on unit
2 retirement assessments. The transmission panel will talk a
3 little bit about that this afternoon, as to how, indeed,
4 that can be done. Just because it's hard doesn't mean we
5 shouldn't try to do it. It incorporates the local capacity
6 premiums in a cost benefit analysis via the current economic
7 planning process. It addresses the local deliverability
8 areas.

9 Some folks, as we are as well, are concerned
10 about the granularity of this approach. There are local
11 deliverability areas that PJM regularly plans around. This
12 would continue, and we would hope that that process would be
13 enhanced by adding an actual local reliability assessment
14 into the local deliverability one, which trades around the
15 CETL intel analysis, and creating a capacity transfer credit
16 for merchants and enhanced local interaction along
17 transmission entities and the local LSEs to take care of
18 some of the problems, mostly to try to put together a
19 protocol and a approach, that plans the entire system; not
20 just the bulk grid, but the entire system in the way it's
21 operated.

22 With that, I'll turn the mike back to you. Thank
23 you.

24 MS. COCHRANE: Our final panelist is Tom Hyzinski
25 with PPL.

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18895
DAV

103

1 MR. HYZINSKI: Thank you. PPL appreciates the
2 opportunity to comment today. PPL believes that an
3 efficient, transparent, stable capacity market structure
4 that allows investors to readily project potential future
5 revenues will promote future investment and assure long-term
6 reliability.

7 An active liquid bilateral market is an important
8 hedging tool, given that no market structure, including RPM,
9 is free of volatility and completely predictable. PPL
10 believes that RPM has several features, such as locational
11 obligations and a demand curve that, if properly
12 implemented, can work. Locational obligations will
13 encourage generation to locate in the proper locations.
14 Implementing a demand curve should reduce volatility,
15 mitigate market power, and provide a more stable revenue
16 stream. Proper implementation of a demand curve may even
17 improve the claims for a better investment climate and lower
18 long-term costs. However, PPL also believes that RPM has a
19 fatal flaw, namely the forward auction that provides a
20 one-year commitment four years out. This RPM forward
21 auction should be eliminated for the following reasons.

22 First, RPM is a non-market administrative
23 solution that would prevent the formation of active and
24 liquid bilateral market, where both load and generation can
25 hedge. PPL's major concerns are that RPM preempts

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18895
DAV

104

1 short-term markets, which increases the risk of doing long-
2 term deals. RPM increases the uncertainty associated with
3 trading five years and beyond, which will also impede the
4 long-term deals. And RPM poses significant credit issues,
5 such as the need to post collateral for five years, which
6 would limit the counterparties in the market, thus, increase
7 costs. RPM has limited pricing points, one base-residual
8 auction and up to three incremental auctions. All auction
9 results will be ex-post pricing. A liquid bilateral market
10 would have continuous price discovery and provide ex ante
11 pricing.

12 Under RPM, PJM would function as a market
13 participant to some degree, rather than just a clearing
14 market administrator. PJM becomes a sleeve for the huge
15 capacity transaction that takes places in the base residual
16 auction. This potentially will expose the member-to-credit
17 risks that they would not have assumed themselves in
18 bilateral contracts with counterparties.

19 RPM would not be conducive to new investment as
20 claimed by supporters. Generation must have a signed
21 interconnection service agreement in order to participate,
22 possibly missing the deadline for the base residual auction.
23 The one-year commitment four years out would not be
24 meaningful to a new generator who needs to recover its cost
25 over many years. In fact, because a generator needs to lock
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18895
DAV

105

1 in year four's price today, RPM introduces certainty that
2 should factor into a generator's offer, which ultimately may
3 increase price. Further, a one-year binding financial
4 commitment four years out is no more binding and provides no
5 more assurance than a firm, liquidated damages provision in
6 a bilateral contract.

7 Finally, RPM would create new machines issues
8 because none of the contiguous RTOs or ISOs have adopted
9 this concept. This will discourage interregional capacity
10 transactions, which will further reduce liquidity.

11 For these reasons, PPL proposes the following
12 specific changes to RPM. First, improve transparency
13 through a visible web site. Generation supply and
14 load-demand data, and information from the RTEP five-year
15 plan, including information about potential local
16 reliability constraints should be assembled, just as it
17 would be for RPM. The key difference is that this
18 information will be made readily available to the market on
19 an ongoing basis. PJM should display this information on a
20 visible, transparent web site that is accessible by all
21 market participants. PPL proposes it be made available at
22 least four years prior to the delivery year.

23 Secondly, set the obligations forward. PJM
24 should set capacity obligations and establish LDAs, based on
25 the assembled information, four years prior to the delivery
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18895
DAV

106

1 year.

2 Third. Move the mandatory auction to allow for
3 robust bilateral markets. Generation and load would hedge
4 themselves by contracting bilaterally up to and until PJM
5 runs a mandatory auction just prior to the delivery year to
6 satisfy any capacity obligations that have not been
7 satisfied bilaterally. Firm liquidated damages contracts
8 negotiated between load and generation would be as
9 financially binding as the results of RPM.

10 Under PPL's proposal, generation and load would
11 both play an active role in determining how capacity
12 obligations are met, based on their respective market to
13 use. PJM would remain the operator on the clearing market
14 and would not become a market participant.

15 Under PPL's proposal, price would be discovered
16 continuously through bilateral contracting. Under PJM, most
17 capacity would be ex-post price at the time of the base
18 residual option, and there would not be any short-term
19 liquidity, aside from a few RPM incremental auctions. Under
20 PPL's proposal, the ability to forward contract would allow
21 multiple use to be hedged t negotiated prices that reflected
22 the dynamic nature of the RTEP and changing generation
23 supply. RPM would only allow load and generation to hedge
24 one year and then administratively set price. RPM, as
25 proposed, will make it impossible for liquid bilateral
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18895
DAV

107

1 markets to develop. It only gives the illusion of providing
2 the forward commitment for generation that PJM so
3 desperately seeks so it can plan transmission adequately and
4 avoid RMR contracts.

5 The real solution to obtaining a forward
6 commitment from generation is a robust market structure that
7 will encourage investment in new generation and the
8 retention of existing generation needed for reliability.
9 For this reason, PPL proposes the elimination of RPM's four-
10 year forward auction in order to allow the markets to work.
11 Thank you.

12 MS. COCHRANE: Thank you, Tom.

13 I guess, first, I'd ask Andy if you'd like to
14 respond to the other alternatives. Specifically, one thing
15 that has come up, it looks like in both of these
16 alternatives, is the idea that perhaps PJM should, indeed,
17 be the entity doing the procurement but have voluntary
18 auctions. If you could address some of those points.

19 MR. OTT: Again, I think the debate is not -- I
20 think if you look at a one-month auction, a one-year
21 auction, a four-year auction, essentially the difference is
22 when you run the auction and when the commitment must be
23 satisfied, as opposed to who is taking ownership or
24 dominating the market. In other words, in either case, PJM
25 is simply running an auction that matches the buyers and
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18895
DAV

108

1 sellers for the residual capacity that hasn't already been
2 contracted for.

3 The difference between the three -- between the
4 one month, one year, and the four year -- is when the
5 commitment must be made. Today, what we have is,
6 essentially, generation has no forward commitment, so we're
7 running the transmission planning process not knowing what
8 generation commitments are out there.

9 To have a voluntary bilateral market structure
10 that says go out and do bilateral contracts -- and what
11 we're going to do is wish real hard that the generation will
12 all be in that contract. But there's really no metric that
13 measures that 100 percent of the generation contract that is
14 needed at some point to allow me to have this certainty in
15 the planning process. That's really the fundamental
16 difference, is when is the forward commitment done.

17 The key here is that the structure in the RPM is
18 looking at setting that forward commitment so that we have
19 certainties, so we know at some point -- and I agree with
20 Tom that when you have the financial commitment in an LD
21 contract -- okay? -- that that essentially says, I have a
22 price, and I have to honor it.

23 That's as binding, if you will, as clearing in
24 the RPM auction. The fundamental difference is if you set
25 that forward commitment four years ahead, then 100 percent

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18895
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109

1 of the generation I need for reliability is set. Now I
2 know, essentially, what the reliability needs of the system
3 are or how they're going to be satisfied. That assists the
4 forward-transmission planning process so that we know what's
5 going on.

6 MR. SINGH: On Ed's proposal, he said you want to
7 make the auction four years and voluntary. I thought of
8 that a few months ago because that would solve the problem
9 of PJ and then being the procurer of last resort. I think
10 the big change here is going from a system-wide auction to a
11 locational auction. When you put in transmission
12 constraints, the only way you can run the model is if you
13 factor in all the supply and all the demand simultaneously.
14 So I can't say to you now that LSCA and LSEB be modeled, and
15 leave out everything else. Then I don't really see my
16 transmission constraints. That's why we need to bring in
17 PJM as the POLR and capture everything else that's not been
18 procured.

19 I don't see how that would work if we are locked
20 into that model of doing everything and PJM doing POLR.
21 I'd like to ask Andy what you think of Tom's concerns about
22 the credit issues and people not wanting to post collateral,
23 making you, essentially, an entity that's doing -- while we
24 don't call them RMR contracts, but it's going to be
25 something like that.

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18895
DAV

110

1 MR. OTT: I agree. I think the key here is if
2 you look at the collateral requirements. Again, if you say
3 that the collateral requirements for any entity is the full
4 amount of the capacity requirement four years out,
5 obviously, that would be an onerous capacity requirement.

6 As we look through the design of the collateral
7 requirements, if you look at the RPM structure, where if
8 someone takes a position, then if they need to get out of
9 that position and they sell in incremental auctions,
10 essentially, now, the collateral requirement becomes the
11 expected difference, if you will, between what the capacity
12 price is on a forward basis and what clears in those
13 incrementals, to actually get a netting, if you will, of
14 some of the credit requirements, which, again, helps with
15 this phenomenon. I do agree that credit, as we look
16 forward, is an issue.

17 On the generation side, since they're the
18 supplier, we have some of the fundamental credit issues.
19 Again, the credit exposure comes down to that differential
20 between the auctions, which is a much lower credit exposure,
21 than the full clearing price in the auction. That does help
22 to mitigate, to some extent, the forward-credit issues.

23 The fundamental concept of saying that you can
24 have a voluntary auction as opposed to -- as you said,
25 essentially, you don't have all the information there to do
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18895
DAV

111

1 the voluntary auction. That's the critical piece. You need
2 all these commitments to come together at some point,
3 certainly in order to make this function.

4 MR. SINGH: The reason for that is location, then
5 I would ask you what I asked Betsy. Which of the two is
6 more important to you, location or the four-year price?

7 MR. OTT: Betsy said you have to have both, and
8 I'll say it a little bit differently. Essentially, if
9 you're saying, okay, I now have location, but I have, on
10 90-day generation retirement notice, to say I'd put location
11 in and I still have that. The fact that I had location
12 isn't helping me a lot when it comes down to the fact that I
13 get to the near term and find I don't have what I need.
14 Again, this forward-commitment to concept is absolutely
15 critical.

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18895
DAV

112

1 MS. SINGH: Of all the ISOs on the market today,
2 PJM is the only one that runs a daily auction. Now you're
3 going the other extreme.

4 MR. OTT: Exactly. Part of this is rolled into
5 new entry, too. We can't lose the new entry piece of this.
6 The point is today we have no meaningful investment model
7 for demand response generation and transmission. The
8 forward commitment, you're sending a signal out with time to
9 act. That's part of it, too.

10 MR. O'NEILL: Andy, why can't you make it
11 optional to the people that Ed represents and the people
12 that Tom represents on the condition that they actually bid
13 into the day-ahead or real-time market so they can be
14 curtailed if their bilateral contracts don't actually come
15 to fruition?

16 MR. OTT: Today I can't curtail them essentially.
17 In other words, I physically can't curtail half the
18 distribution feeder and not the other half.

19 MR. O'NEILL: So you would need the equipment, so
20 maybe a condition upon which you could make this thing
21 voluntary is that they have the equipment to bid and be
22 curtailed?

23 MR. OTT: So I should shut them off, you're
24 saying?

25 MR. O'NEILL: If their promise to make the
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18895
DAV

113

1 bilateral commitment work didn't materialize -- one year is
2 probably too late to make sure that the commitment doesn't -
3 -

4 MR. OTT: Again, that feature exists in the RPM
5 today, essentially what I'll call load curtailment, which
6 today I believe is called ALM. In PJM we have another
7 acronym, ILR, under the RPM. But essentially the avoidance
8 of the capacity payment by curtailment essentially is part
9 of the model. You can do that within three months of the
10 delivery year, you can come forward and say I want to opt
11 out and essentially you'll forecast that ahead of time,
12 where they can wait until the last minute and say I'm going
13 to avoid the payment by essentially curtailing. That is
14 part of the model.

15 MR. O'NEILL: The biggest part of making it
16 voluntary is that when you go to curtailments you can't
17 focus the curtailments on the people who aren't resource
18 adequate. If you could do that, you could make it
19 voluntary.

20 MR. OTT: I think that exists today for the ones
21 that can step up and do that.

22 MS. COCHRANE: I was going to ask Ed and Tom if
23 you'd like to respond. I guess I thought -- Ed, could you
24 respond to what Andy said about how you wouldn't have
25 basically enough of the information coming out of a

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18895
DAV

114

1 voluntary auction that they need to be the ones doing that
2 because they have all of the information as far as
3 transmission planning.

4 MR. TATUM: Thank you.

5 There is an implicit assumption here that we're
6 going to do our best not to buy any capacity whatsoever. We
7 don't operate like that. We just don't do that. We have
8 reliability obligations, we are load-serving entities, and
9 we can't behave in that way.

10 Number two, we're talking about quarterly
11 auctions, four auctions a year for any time period out. We
12 feel that's going to be providing some good information as
13 to what's out there. So there's going to be a certain
14 component of the resource obligation that will have to come
15 from within that area. That's going to be set and
16 determined and we will have to buy that amount and be there
17 for it. The rest we can get from the general broader
18 market.

19 If we don't perform at the very end of the
20 process right before the planning, there's a final clearing
21 auction where everybody comes into the church, we shut the
22 doors, and it's not done until it's done. That's how we
23 would be working under this proposal.

24 MR. HYZINSKI: I think the difference in opinion
25 as to whether this four year forward commitment is necessary

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18895
DAV

115

1 or not comes in a different view of where the problem comes
2 from. I just don't think that you could ignore the fact
3 that you have an unhealthy market structure and say that
4 you're not getting the stream of investment generation that
5 you'd like to see on a forward basis. It's hard to argue
6 that if you had healthy market structure that you wouldn't
7 see the investment that you want. As a matter of fact,
8 we've contended that this one year commitment four years out
9 is not really a surety that generation will be there, it's a
10 binding financial commitment, just as a bilateral contract
11 is.

12 So one could say that you'll know that generation
13 is coming when you see it coming. When you have a healthy
14 market structure that provides for investment, you will have
15 investment and you will see it on a forward basis. Then
16 you'll be able to do your transmission planning because you
17 will know what resources you have to work with.

18 So in tackling the problem, we can't ignore the
19 fact that we're trying to fix a market structure which we
20 claim is broken, yet we want to say that the market will not
21 bring us the investment we'd like to see.

22 MR. O'NEILL: Could you define what you mean by
23 "a healthy market structure?" I'm not sure I'd know a
24 healthy market structure when I see it.

25 (Laughter.)

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18895
DAV

116

1 MR. HYZINSKI: For starters, we have a market in
2 place in PJM now where we have a vertical demand curve which
3 has a lot of volatility to it, we have no locational aspect,
4 which will obviously cause generation to be built in the
5 wrong place as the PJM board has acknowledged in some of
6 their letters to the membership.

7 We also have a target, an IRM, of 15 percent that
8 was dropped from, I believe, 17 percent during the same time
9 period that the level of reserves was rising from, I think,
10 roughly 17 percent up to about 25 percent, where it is
11 today. So when you lower the target in response to a rising
12 level of reserves that was responding to an earlier price
13 signal and you have no locational requirement, you have a
14 vertical demand curve which, oh, by the way, is further
15 aggravated by a daily auction, you have a market structure
16 that you have today, which incited some supply early on but
17 now is failing to produce adequate revenues. So that's an
18 unhealthy market.

19 Now if you would do something to fix the IRM
20 problem and the vertical demand problem -- like the four-
21 year demand curve, you would put in a locational requirement
22 as we believe you would create the environment for active,
23 short, medium and long-term bilaterals, then I think you
24 have a market structure that would be conducive to
25 investment. You have a predictable revenue stream, somebody
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18895
DAV

117

1 can look at that and say over the long haul I believe I'll
2 get my money back and they'll invest in that market.

3 MR. O'NEILL: So you just object to the term of
4 the auction, but you agree with most of the other aspects?

5 MR. HYZINSKI: Yes.

6 MR. O'NEILL: Ed, is that your position?

7 MR. TATUM: No, sir.

8 (Laughter.)

9 MR. TATUM: You got Tom right, though.

10 MR. BANDERA: So we just heard that Tom's main
11 difference is that four year forward isn't where he wants it
12 to go. Yours fundamentally is?

13 MR. TATUM: Our fundamental is that we want to do
14 an incremental change to the existing construct. We agree
15 the construct needs to change, but we don't think we need to
16 take it as far as we're talking about now. Clearly, there
17 does need to be change. That's one major difference.

18 The other part of it, too, is we are trying to be
19 more market-oriented with that. We have faith in the
20 competitive marketplace and we think that by going with
21 these voluntary auctions this will be an improvement by
22 setting a locational constraint that will meet the needs
23 without bankrupting load-serving entities.

24 The other difference that we've got going on,
25 this coalition has, is that we do not at this point

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18895
DAV

118

1 subscribe to the demand curve. The major reason we do not
2 subscribe to the demand curve is because, as far as the
3 trade-off between the supposed reduced volatility, we see a
4 very high price to pay for that reduced volatility. We
5 think there is a certain finite pot of dollars that we as a
6 nation have to invest in certain things and the consumers
7 and the folks that pay us to supply them electricity have a
8 certain limited supply of funds. If we have to invest in
9 something, we want to invest in infrastructure and
10 transmission, as well as needed generation locally.

11 MR. BANDERA: So you all are in agreement that
12 there needs to be a more locational-specific element to the
13 PJM capacity structure?

14 MR. TATUM: Absolutely.

15 MR. O'NEILL: And who will determine how the
16 locations are derived, PJM?

17 MR. TATUM: Certainly, under certain protocols
18 that we set up and talk about and the characteristics of
19 those areas. That's another area where we have a
20 difference, because we want to redress the resource
21 adequacy, the capacity issue, on a wider basis than what is
22 being proposed by PJM.

23 MR. O'NEILL: Have you changed your position from
24 before? My understanding before was that you were going to
25 have zones that really were not physically compatible with
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18895
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119

1 the actual reliability of the system and then you were going
2 to clear the market and use RMR contracts to clean up the
3 mistaken belief that you have too large zones. Have you
4 changed since then?

5 MR. TATUM: No. I'd rather recharacterize your
6 question.

7 (Laughter.)

8 MR. TATUM: Again what we're talking about is
9 local market areas that are based, from a resource adequacy
10 standpoint, through the transmission portion. We are
11 retaining the local deliverability area concept. These are
12 the areas that we can talk about this afternoon with Steve
13 Herling and the transmission planners that I guess we would
14 call electrically cohesive. That they are small and we
15 recognize that in those areas we will continue with the
16 current PJM planning process and analysis, if you will, of
17 the capacity, the CETL, which is the emergency transfer
18 objective and the limit, and take a look at that, try to
19 enhance it on a two-year basis going forward. So if we do
20 see a problem -- which we would hope would not occur, but we
21 would then try to address that through a competitive RFP or
22 an auction.

23 MR. BANDERA: You don't think it's necessary for
24 PJM to know four years ahead exactly what generation units
25 are going to be there and you don't see the need to link

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18895
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120

1 those -- that transmission planning and the generation
2 identification four years forward?

3 MR. TATUM: Derek, transmission planning needs to
4 anticipate what the future generation pool's going to be.
5 We believe there are ways to do that, by going out longer
6 term, but also mixing an approach of probabilistic analysis
7 in the longer term with the current more deterministic
8 approach that we are currently using in the shorter term.

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121

1 MS. COCHRANE: Any questions from the states? Go
2 ahead, David.

3 MR. MEAD: A question for Tom: One of the points
4 I think I heard you make, was that the four-year procurement
5 that only offers a one-year contract, will not really create
6 a viable climate for new entry.

7 And I'm trying to figure out the implications of
8 that. Is the implication that you think that if there is a
9 four-year forward procurement, there isn't going to be
10 enough supply that offers in to meet the requirements that
11 are forecast, or, is it that supply will be so short, that
12 just the price will be more expensive than under your
13 proposal, or is it something else?

14 MR. HYZINSKI: I think it's just not as good of a
15 signal as a liquid, bilateral market would be. It's a one-
16 year signal, four year out. It's an ex-post price.

17 You don't know what the price is, until after the
18 auction has cleared. It's not like you have a liquid
19 bilateral market that you can go to for the short term,
20 where you could hedge yourself.

21 If you would elect to do a long-term deal, I
22 think there's a lot more risk in selling a ten-year strip,
23 knowing that at any point in time, if I would have a
24 problem, I can't go to a liquid bilateral market and hedge
25 that.

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18895
DAV

122

1 I just think it doesn't provide the liquidity and
2 the price discovery you'd like to have in order to mitigate
3 risk. That's our main issue with it, and I think that the
4 liquid market is much more conducive to investment.

5 MS. COCHRANE: Just one more question.

6 MR. BANDERA: Does Andy have a response to that?

7 MR. OTT: I think if you look at this, we're
8 talking about market-oriented, versus not. That's really
9 not, again, the issue.

10 The issue is, what are you telling the market you
11 want? All three of these proposals are market-oriented,
12 meaning they send the signal, they have an auction, they
13 invite participation.

14 I think if you say, okay, say, three years from
15 now, I have an area where I have 10,000 megawatts of load,
16 and I can only serve 5,000 of it from outside, if I have a
17 voluntary auction, only the 5,000 that I can serve inside,
18 from outside bids in that area, then I have no forward
19 signal that I've got a problem, until we get to the point
20 where, okay, now it's mandatory that everybody show up.

21 Suddenly, they all show up, and I say, oh, my
22 goodness, I've got a problem. I saw no forward signal for
23 transmission investment; I saw no forward signal for demand
24 response at that point. I just got to the point where I had
25 a problem, then I've got to do something.

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18895
DAV

123

1 The concept of having the price set, meaning that
2 you have to have 100-percent participation -- and, again,
3 it's not mandatory participation in the auction, because you
4 can bring in your own bilaterals -- the point is, I've
5 actually revealed to the market, ahead of time, with an
6 actionable signal to allow investment to occur, and whether
7 that investment is a transmission build or upgrade, a demand
8 response, or a generation asset, the point is, if we're all
9 going to do forward bilateral contracting anyway, why not
10 tell us all about it, so that we can put it in there and we
11 know what's going to occur, so we can actually get a
12 competitive investment model that's driven by the market?

13 The point is, if you wait too long, the only
14 thing you can do is an RMR contract or shed load. Let's get
15 realistic about it.

16 If you want to get investment done, you've got to
17 send a signal out long enough in advance to get it done.
18 And you can't do it by saying half the load can show up.

19 I can tell you what that price will be: It will
20 be low.

21 MR. HYZINSKI: I just want to make sure I
22 understand that example, because you had said that only in
23 your voluntary auction, only load outside the area would bid
24 into that, and if you didn't have the load inside bid into
25 that, you wouldn't have surety that you could use to do the

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18895
DAV

124

1 transmission plan.

2 I think we can't mix up a financial commitment
3 with the assets that are physically there. That generation
4 is still there in that load pocket, whether it bids into
5 that auction or not, and just like the generation that's
6 coming in the queues that's coming up in response to the
7 signals for new investment, it's really there.

8 Whether you want a forward auction or not, it's
9 really there. What you have to do is create the environment
10 for that investment to want to happen. That's the key.

11 MR. SINGH: I want to say one quick thing to Andy
12 about sending the price signal, four years ahead. It's a
13 little point, yet to weigh it against the arguments Tom
14 made, I would say that if the demand curve is fixed for
15 three or four years, it's going to be an administrative
16 thing, anyway, so people know that there is some certainty
17 coming from how you fix that demand curve.

18 Given their own forecast of the fundamentals,
19 would they not be able to get some of those signals anyway,
20 even if you had a one-year-ahead auction?

21 MR. OTT: Yes, I think that's the key. You have
22 to have somebody step up and say it's my responsibility, and
23 I think that that's probably the critical piece, is to say,
24 can I get the folks to step up and say I'm going to go ahead
25 and do the bilaterals?

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18895
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125

1 And if I get 20 percent of them showing up,
2 versus 80 percent, versus 100 percent, obviously that
3 matters a lot.

4 I think what we're saying here is that, today, I
5 think we've seen that. We haven't really had -- we're
6 putting out the, quote, voluntary, and I realize today that
7 the market is daily, but even with a monthly or annual
8 market, saying, you know, step up and do it voluntarily, I
9 don't think really has been working.

10 There's always this concept that, hey, I can just
11 dump it back on somebody else, or try to do something on a
12 shorter-term basis. I don't think the reality is that
13 you're going to see the voluntary. And it may cover part of
14 the load, but it's not going to cover all of it.

15 Again, my responsibility is to make sure it gets
16 all covered. I'm not procuring the capacity, as much as
17 making sure the generators are committed. That's really the
18 key.

19 MR. KATHAN: I had a question for Ed, related to
20 what Roy was talking about this morning, and probably we'll
21 also probably hear this afternoon when Professor Hobbs
22 talks. You made a comment about the demand curve and its
23 time dimensions, that it is going to be more costly to have
24 the demand curve.

25 Is that a short-term issue; is that a long-term
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18895
DAV

126

1 issue? What is the time dimension of your concern?

2 MR. TATUM: Yes.

3 (Laughter.)

4 MR. TATUM: All the way. The demand curve, the
5 concerns of the demand curve, is, again, what is the shape
6 of the demand curve? How high is it? How wide is it?

7 Those types of issues are of concern. The other
8 aspect of it, as I alluded to earlier, though, is the finite
9 pot of dollars that people have to invest in certain things.

10 What are they going to be investing in? Are they
11 going to be investing in infrastructure to engender robust
12 and competitive markets, or are we going to be investing in
13 localized generation? That's just a big question as to how
14 people want to do that.

15 The other part if, too, though, is that we are
16 concerned about the overall cost over the years. We've had
17 a number of simulations that have been run and people have
18 taken off their own numbers from those simulations, based
19 upon different assumptions, and in a year, we see 2.6 to 2.7
20 billion, depending on whether it's optimized or not
21 optimized.

22 We have all these other numbers. Those are big
23 numbers, so we see that as a very large difference in the
24 amount of capacity and the payment that would be forwarded.

25 MR. O'NEILL: Could I just get a clarification?

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18895
DAV

127

1 Did you say you weren't opposed to the demand curve; you
2 were simply opposed to the shape of the demand curve?

3 MR. TATUM: No, sir. I said that my coalition is
4 opposed to the demand curve, for the reasons that I set
5 forth.

6 MR. O'NEILL: But then you said something about
7 the shape. You didn't like the shape, or you needed to
8 change --

9 MR. TATUM: Some people are concerned about the
10 shape, some people are concerned about the slope, so I've
11 got a coalition here that I'm representing.

12 MR. O'NEILL: But there is demand curve, anyhow;
13 it's just very steep?

14 MR. TATUM: You know what? We have learned so
15 much since June of this year, and we really, as a pool and
16 as an RTO, have come a long way to have everybody sitting
17 here with these common issues, yes, we need location; yes,
18 we need to fix it.

19 That's a huge step from where we were a year ago,
20 whether some people think it's big or not, but, yes.

21 MS. COCHRANE: Thank you. I think we'll be
22 addressing a lot of these issues in more detail this
23 afternoon. Why don't we break now for lunch. We'll try to
24 start promptly at 1:15, to give you guys an hour.

25 (Whereupon, at 12:15 p.m., the Technical
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18895
DAV

128

1 Conference was recessed for luncheon, to be reconvened this
2 same day at 1:15 p.m.)

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18895
DAV

129

1 AFTERNOON SESSION

2 (1:20 p.m.)

3 MS. COCHRANE: If people could please come on in
4 and take a seat, we can get started.

5 (Pause.)

6 All right, it's time to get started with our next
7 panel. This afternoon, the way that we've structured the
8 panels, is pretty much to break down the different elements
9 in the capacity market, and the proposed alternatives, into
10 kind of two buckets.

11 This is the transmission planning, integration,
12 and related issues panel, so why don't we go ahead and get
13 started? I know a lot of the issues have been raised in the
14 previous panels.

15 If you were here this morning and you heard
16 things that were raised in the previous panels that you
17 would like to respond to, please go ahead and do that.

18 But our first panelist is Steve Herling,
19 Executive Director of System Planning for PJM. Thank you,
20 Steve.

21 MR. HERLING: Thank you. Obviously, as we've
22 seen this morning, the issues underlying RPM, are extremely
23 complex. One of the themes you'll hear consistently from
24 PJM, is that for any solution to succeed, it has to be fully
25 integrated across planning markets and operations.

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18895
DAV

130

1 All three have to work together or whatever we
2 put in place, will not give us the desired result. In
3 parallel with the RPM effort, we have initiated a number of
4 significant changes or an evaluation of a number of
5 significant changes to the planning process, including:
6 Extending the planning horizon and expanding the focus,
7 based on which we plan, with respect to what it takes to
8 support a robust, competitive market.

9 Our recent experience illustrates the need for
10 integration of integration and transmission solutions and
11 demand-response solutions and the need for longer-term
12 certainty, as it impacts the planning process.

13 The deliverability problems that we're currently
14 dealing with in New Jersey, highlight the need for
15 appropriate market signals to generators, to all resources,
16 so that generation, transmission, and demand response, can
17 more effectively be integrated within the context of the
18 planning process.

19 The RPM proposal builds on the relationship
20 between generation and transmission, using our existing
21 deliverability criteria and tests to develop and put
22 forward, the signals to the market, to incent the behaviors
23 that we're looking for.

24 RPM specifically provides for an opportunity for
25 transmission to compete with generation and demand to
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18895
DAV

131

1 resolve the capacity shortages, locationally, as we move
2 forward, and, as we've seen, our experience over the last
3 seven or eight years with deliverability, indicates a need
4 for granularity in terms of how we evaluate the problems and
5 how solutions are going to be provided to resolve the
6 individual problems and constraints we face.

7 If you look at the last couple of years, we have
8 had a significant number of generation retirements announced
9 in 2003 and 2004. I dug this up, based on some of the
10 comments this morning.

11 If you look back in the four years, 99 through
12 2002, in the Mid-Atlantic region, we had a total of 269
13 megawatts of generation retirements; in 2003 and 2004, we
14 had 1400 megawatts, a significant portion of that in New
15 Jersey, and we have another 1200 megawatts pending, that
16 requested retirement, which we have determined are needed
17 for reliability.

18 We need to keep those units around for a little
19 while. The problem we have is that while generation is
20 critically needed in the East, in particular, in New Jersey,
21 there is no locational evaluation for generating capacity,
22 and because we don't have any kind of long-term forward
23 commitment process, generators are essentially able to
24 announce their retirement, effective immediately.

25 Obviously, we have a 90-day period during which
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18895
DAV

132

1 we can evaluate, but that really doesn't give us much
2 opportunity to do anything other than the RMR solution that
3 we've been talking about.

4 As a result of these retirements, we've
5 identified deliverability criteria violations for every year
6 of our planning period. We're looking out into the 2010
7 timeframe now, but in the retirements we saw recently, we've
8 identified violations for 2005, every year from 2005, out.

9 We've been able to resolve the violations for
10 2005 through a combination of very quick transmission fixes
11 that were able to be implemented, and the RMR contracts for
12 a number of generating resources, but, moving forward, we're
13 going to need to implement additional transmission fixes in
14 the short-term years of 2006, 2007, 2008, and 2009, based on
15 those retirements, and we're going to have to keep those RMR
16 generators around for some period of years, based on the
17 pace of that transmission construction.

18 The RMR generation is clearly a short-term
19 solution. It's a transition to a reliable state further
20 down the road, while we build longer-term solutions.

21 In this instance, the transmission solutions are
22 just going to take a number of years to put in place, but if
23 the generation capacity was given a locational valuation, if
24 it's critical to have generation capacity in a particular
25 area, and if capacity was valued accordingly, then the

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18895
DAV

133

1 existing generation, if it is viable for the long-term, they
2 would have the incentives to keep those units in a state
3 that they can participate in the markets for the long haul.

4 It would also send signals to the developers to
5 put resources where we need them.

6 I mentioned before, that, in parallel with all
7 these activities around RPM, we're also looking at our
8 planning process. Our Board -- and I believe this is
9 attached to my comments -- our Board put out an open letter
10 to our membership, basically committing us to a series of
11 activities, and, in particular, with respect to the planning
12 process that would look at what it would take to extend the
13 planning horizon, based on what we currently do today, and
14 to take a much broader look at the economic elements, what
15 it takes in planning, to build with respect to a robust,
16 competitive market.

17 Those efforts, we've already initiated. They're
18 going to be rolling out through our stakeholders over the
19 remainder of this year.

20 But one of the things that we need to be aware of
21 -- and I think this was said numerous times this morning --
22 is, the two have to work together.

23 The changes we made to the planning process, have
24 to work with RMP. If we change the planning horizon, the
25 certainty issue, the longer-term commitment, becomes even
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18895
DAV

134

1 more critical.

2 The further out we plan, the more uncertainty
3 there is, so the more critical that certainty becomes. Our
4 linkage to the RPM cycle is certainly doable.

5 We just have to balance the planning horizon, the
6 auction cycle, the margins that we apply around our
7 deliverability tests. We can do that for any combination of
8 planning process or planning horizons that we might choose
9 to implement.

10 The premise of RPM as the generation,
11 transmission, and demand response, are going to compete to
12 resolve these deliverability constraints. We've identified
13 deliverability constraints, all across the PJM system, for a
14 wide variety of areas, from portions of transmission owners'
15 service territories, all the way up to huge aggregations of
16 multiple states.

17 The solution has to fit the problem. If it's a
18 transmission solution, it has to be designed to resolve the
19 problem, whether it's a small portion of one system or
20 multiple-state parts of the PJM market.

21 If you are going to have transmission and
22 generation competing to solve problems, they have to have
23 the same level of granularity. If we use granularity for
24 transmission solutions, you have to have the same
25 granularity for generation, to solve the problem.

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18895
DAV

135

1 Otherwise, generation would be built,
2 potentially, in this very large region, but not actually
3 getting to the constraint that was driving -- if you didn't
4 have the granularity, that was driving the higher capacity
5 price.

6 So, it's absolutely critical that we synchronize
7 the granularity of the transmission solutions with the
8 granularity of the generation solutions.

9 I do have -- I dug up over lunch, a number of
10 elements, based on some of the things that Roy and others
11 teed up for me this morning. If you'd like, I could just
12 pick those up as we go through the discussion afterwards,
13 but that's the end of my prepared comments.

14 MS. COCHRANE: Our next panelist is Craig Baker,
15 Sr. Vice President for Regulatory Services, with AEP. Thank
16 you, Craig.

17 MR. BAKER: Thank you. AEP appreciates the
18 efforts put forth by the Commission in arranging this forum.
19 I want to thank the Commissioners and the Staff for the
20 opportunity to present our thoughts regarding the capacity
21 markets within PJM.

22 To summarize our position, regulated utilities
23 should be able to meet the capacity requirements by self-
24 supply at the approved IRM.

25 The existing capacity construct should be
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18895
DAV

136

1 modified to integrated transmission planning into the
2 capacity planning process, which I think Steve was
3 mentioning.

4 And new rules need to be developed on regional
5 transmission pricing to make sure that transmission and
6 long-term generation planning, fit together well.

7 Being a vertically-integrated utility, operating
8 in seven state jurisdictions, I think AEP is in a slightly
9 different regulatory framework than the classic members of
10 PJM, and the proposal, as it's been outlined, does not
11 adequately, in our minds, recognize these facts.

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18895
DAV

137

1 At present, one of the things we've noted is that
2 all the PJM markets are considered voluntary. However, the
3 PJM-proposed RPM solution, the effects of it are mandatory.
4 Let me give you an example.

5 When we think of the IRM and what we thought
6 about when we joined PJM, it was that we would have reserve
7 requirements in the 15 percent range. We expected we would
8 be able, as a vertically-integrated business, to be able to
9 build that generation, have it available, and meet the
10 reserve requirements. As we understand the RPM proposal,
11 the first thing you see is an increase of 1 percent in that
12 value and then the potential in which you have a clearing
13 that might be in the 18 to 20 percent range -- which, even
14 though we had built 15 percent, brought it to the market,
15 that was adequate under PJM criteria to meet the loads in
16 that area -- we would be required to in effect purchase from
17 your capacity market even though we would have had enough to
18 meet the reliability criteria.

19 AEP strongly believes that the capacity market
20 design must consider the fact that there are vertically-
21 integrated utilities where generation is directly tied to
22 serving the load. Our customers do not pay market prices
23 for their commodity supply. What they pay is an embedded
24 cost based on the installed cost and the operating cost of
25 our units. The vertically-integrated units in a regulated
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18895
DAV

138

1 environment continue to plan resources in an integrated way,
2 developing least cost solutions that assure customers our
3 needs are met in an economic and reliable manner on a long-
4 term basis.

5 In our short stint in PJM -- we're relatively the
6 new kid on the block, or one of the new kids on the block --

7 I've seen a lot of progress in PJM attempting to really
8 integrate the markets, the transmission, through the RTEP
9 and through the demand response program, but they do have a
10 way to go.

11 When we think about it and the concerns that I
12 think have been addressed by people is who's going to bring
13 the generation to market. What I know is that the states
14 that we do business in are very interested in AEP building
15 generation. So it is not a concern that will somebody come
16 and build it, we're going to build it. We have the proposal
17 in front of the Ohio commission to build a 600 megawatt IGCC
18 facility, they are very supportive of that, and there are
19 other commissions looking at the same thing. I think as
20 long as a utility can demonstrate its ability to meet the
21 reliability requirements established in the reliability
22 planning process, we should be okay.

23 Another way to say this is a vertical demand
24 curve that's set at the IRM. We believe the potential
25 capacity problems in certain PJM areas could be alleviated

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18895
DAV

139

1 by reliably integrating resources within the entire PJM
2 footprint through adequate transmission.

3 I think that PJM has gone a long way, I
4 understand they had on the table about \$130 million in
5 transmission enhancements in the New Jersey-Pennsylvania
6 area. I think that's going to go a long way.

7 There's talk of the RMRs. We have some
8 experience with that. We believe RMR is not an efficient
9 long-term solution, but it does provide short-term relief
10 for local reliabilities, while long-run solutions such as
11 transmission can be developed.

12 In Texas we experienced that. In Texas we had
13 markets -- when they went to markets they realized the
14 lowest-cost generators couldn't necessarily keep the
15 transmission grid built or stable, so what happened was
16 there were RMR units, there was a very effective regional
17 pricing proposal that had immediate recovery and people
18 immediately started building transmission in order to get
19 rid of the RMR contracts. A significant number of them on
20 our system are gone, and I would liken it because of the
21 regional pricing proposal.

22 We would urge PJM to consider modifying the
23 existing capacity construct to address regional needs
24 through the stakeholder process using RMR as a short run
25 solution. Ed Tatum earlier today indicated that PJM has
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18895
DAV

140

1 come a long way in this process. I believe they have as
2 well, but I think we need some more time to talk about
3 possible solutions. ODEC has a proposal that goes a
4 significant way in meeting our needs.

5 We need to strengthen the existing transmission
6 infrastructure and, in order to trigger transmission
7 investment in PJM on a regional basis, AEP urges the
8 Commission to consider the following solutions: expand the
9 RTEP process to ensure further participation of transmission
10 in the capacity construct. I think we're making some
11 progress there.

12 Develop a sustainable regional transmission
13 pricing structure to reduce the uncertainty of transmission
14 investment. I believe this will help the Commission to
15 achieve its goal of providing low-cost energy for customers.
16 We are experiencing a situation in front of us where the
17 regional pricing of sorts that was in place has gone away.
18 We are going to be absorbing -- our customers are going to
19 be absorbing the full cost of the AEP transmission system in
20 April of next year. Our customers, our commissions, are
21 already talking to us about how they believe that others who
22 take advantage of the AEP system should pay part of that
23 transmission fee, adding new transmission on top of that.
24 Without a good regional pricing proposal, I don't think that
25 will be looked on kindly by our state commissioners or our
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18895
DAV

141

1 customers.

2 That's the end of my prepared comments.

3 MS. COCHRANE: Thank you, Craig.

4 Our next panelist is Laurie Oppel with Navigant
5 Consulting.

6 MS. OPPEL: Again, I want to thank the Commission
7 and also the Staff for the opportunity to be here today. I
8 want to take a comment that Roy made and say these are my
9 personal opinions and do not reflect the opinions of
10 Navigant Consulting or any of our specific clients.

11 Resource adequacy or capacity markets is clearly
12 a reliability consideration with clear economic
13 considerations depending upon the ability to predict the
14 problem and plan for that solution. PJM is not alone in
15 trying to determine how to address transmission planning in
16 the current and proposed capacity markets. For example, the
17 demand curve construct in New York has not promoted new
18 generation development, but it may have aided in deferring
19 or delaying generation retirements.

20 One could potentially draw the conclusion that
21 locational requirements, locational capacity requirements
22 that exist in New York was a driver in LSE investment in new
23 major transmission. This investment was a response to a
24 proactive solicitation by that LSE with no assistance from
25 the ISO and was not identified in any of the planning
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18895
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142

1 processes.

2 The New York State Reliability Council currently
3 is studying how to make calculation of the installed reserve
4 margin and the locational requirements consistent, basically
5 by prorating capacity reductions until a one-day-in-10-years
6 LOLE is achieved universally.

7 The New York ISO, as I'm sure Commissioners are
8 aware, is presently evaluating potential inconsistencies
9 between their installed reserve margin study assumptions and
10 the regional planning assumptions for reliability. For
11 instance, the time frames of the installed reserve margin
12 studies to set the state-wide and locational capacity
13 requirements are done approximately six months prior to the
14 capability period, clearly not enough time to build new
15 generation if you find as an LSE that you would fall short.

16 Planning studies for reliability consider a five-
17 year and 10-year horizon but fail to consider resource
18 adequacy as a reliability consideration presently. The
19 study methodology, for instance, there's differences also
20 between the installed reserve margin studies: they use GE's
21 MARS analysis, a probabilistic method. The planning studies
22 will primarily use a program called PSSE, a traditional
23 deterministic approach to transmission planning.

24 Furthermore, the assumptions are inconsistent
25 between setting the capacity requirements and planning the

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18895
DAV

143

1 transmission grid. The IRM studies do not consider
2 retirements or addition of generation more than one year
3 out. The planning studies consider only a limited number of
4 scenarios. When you're looking at a five-year and 10-year
5 horizon, clearly one needs a crystal ball.

6 The development of the transmission grid has
7 largely been undertaken with deterministic planning
8 criteria. Commonly-held standards which many transmission
9 planners in here refer to as n-1 and n-2 criteria whereby
10 the grid should be designed to maintain supply to customers
11 in the event of loss of a single or multiple contingency.

12 Typically these studies are conducted under peak
13 or light load conditions and evaluate a worst-case
14 generation dispatch, which may or may not be reflective of
15 reality or operational considerations if done for each
16 contingency, regardless of the relative probability of those
17 contingencies. In practice, this criterion is pretty easy
18 to understand, single contingency, multiple contingency
19 deterministic approach. It's also very easy to apply,
20 relatively easy. The downside is that it results in the
21 development of a network that can quite frequently be
22 underutilized except for very short periods during high
23 demand and may not provide for a robust transmission grid.

24 Unfortunately, this deterministic methodology of
25 transmission planning has not served to promote transmission
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18895
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144

1 development to preserve or enhance the competitive energy
2 markets.

3 The problem you will frequently see addressed
4 though is if we have certain levels of uncertainty. Very
5 clearly in the competitive markets we do, because we're not
6 completely sure of demand side response, generation,
7 addition, retirements, transmission capability, whether or
8 not lines will be reconductored or new lines will be added,
9 load factors concerning weather and also equipment failures.
10 With all the levels of uncertainty and all the combinations
11 and permutations that need to be undertaken, it's very
12 difficult to use a traditional planning approach to try to
13 build a robust grid which will withstand all the
14 combinations due to that uncertainty.

15 The application of the probabilistic planning
16 methods allow for a wide variety of scenarios to be
17 evaluated to accommodate these levels of uncertainty and
18 will assist in avoiding these limited return projects.
19 There are commercial tools available and they're gaining
20 more and more acceptance throughout the industry, both
21 within the United States and abroad. Those tools that are
22 available though have a varying level of generation and
23 transmission detail. It's imperative to find the right
24 combination between the transmission and generation detail
25 to plan for the future grid.

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18895
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145

1 Some recommendations for planning considerations
2 in the various capacity market constructs. The planning
3 horizon timeframe, I'm suggesting that there are two
4 periods: the first four to five years, and the second four
5 to five years. Consider the continued use of a
6 deterministic methodology for the first period of time but
7 migrate to a probabilistic methodology for the second period
8 of time to evaluate a variety of scenarios, because that's
9 basically where the levels of uncertainty clearly come into
10 play. And look at variations in load growth, generation,
11 addition, retirements and possible transmission development.

12 By using this probabilistic approach, a wide
13 variety of scenarios can be evaluated quickly and determine
14 if there is a common thread to some of the problems that are
15 arising. You can also define an index associated with the
16 potential impact of those scenarios. This hybrid approach
17 would be basically a combination of the deterministic and
18 probabilistic methodologies. Consider coordinated functions
19 between the reserve margin studies and the planning studies.
20 Align the planning criteria and the operational
21 considerations of the grid, both bulk and local. Balance
22 the transmission and resource planning approaches. Plan for
23 the bulk system regionally, but evaluate the zones and
24 locations on a more granular basis to avoid further
25 balkanization of those capacity localities.

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18895
DAV

146

1 For instance, one thing evaluated presently in
2 New York is whether or not there should be a requirement in
3 the interconnection standard to have deliverability within
4 the localities. Very clearly if the transmission constraint
5 occurs in the existing locality, then that capacity locality
6 would be potentially split into two or all the capacity in
7 that locality which is currently resource constrained would
8 have the location requirement increased.

9 Incorporate resource adequacy as a reliability
10 consideration in the RTEP process. Here again I'm going to
11 agree with Roy to accommodate some short-term needs due to
12 the forced outages or little advanced notice of generation
13 retirements, consider either deployment of mobile
14 generators, construction of peakers, or the short-term RMR
15 contracts. This is short-term solutions, but plan for the
16 longer-term more economic solutions of the grid.

17 Consider extending notification of generation
18 retirements from the current 90 days to 12 to 24 months.
19 Evaluate economics of the bulk transmission upgrades between
20 localities and zone to minimize the proliferation of these
21 load and capacity pockets, as well as the evaluation
22 criteria should examine the reduction in production costs
23 with the costs of the transmission investment since load
24 pays all actually at the end of the day.

25 Cost allocation for transmission investment;

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18895
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147

1 consider looking at socialization of the bulk transmission
2 upgrades similar to how New England accomplishes it and, if
3 it's a localized upgrade, apply it to the local loads within
4 the region.

5 Thank you again. That concludes my comments.

6 MS. COCHRANE: Thank you, Laurie.

7 Our next panelist is Gary Sorenson, Managing
8 Director of Energy Operations for PSEG Energy Resources and
9 Trade.

10 MR. SORENSON: Thank you very much for this
11 opportunity. This is very important to my company.
12 Although we're seen as a generation owner, we're also a
13 transmission owner and a large load-serving entity.

14 My own background, I've worked in generation,
15 system operations, transmission planning, production
16 costing, integrated resource planning before I came to the
17 trading floor. We believe an absolute holistic approach is
18 necessary. Generation, transmission and demand side has to
19 all be considered, but we also believe RMR's have no place
20 in the construct of RPM. They're needed now because we have
21 a market problem, but going forward there's no place for
22 RPM's.

23 Some of the things we must understand is what was
24 talked about earlier today, the concept of universal
25 deliverability. What does that mean? In PJM, we have major
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18895
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148

1 interface limits, west central and eastern limited around
2 the 7,000 megawatt area and 30,000 megawatts of peak load in
3 the east. It's very obvious that every load in eastern PJM
4 cannot buy Western Kentucky coal. So if universal
5 deliverability means I am a load in one node and I wish to
6 be able to get generation from anywhere that is cheapest.
7 That's now how the transmission system was built. If you
8 wish to reinforce the transmission system in that way,
9 you're talking three or four times what it is now.

10 So universal deliverability isn't every load fits
11 the generator. What you have is a combination. Obviously
12 in eastern PJM we have nuclear units, we don't want to
13 replace them with western coal. So it's balance, it's not
14 everything from outside the zone and nothing inside the
15 zone.

16 What really happened -- and PSEG had to apply for
17 RMR contracts, and why wouldn't this be needed under RPM is
18 a big issue. For PSEG, the units we applied for RMR
19 contracts have lost money for the last three years. It is a
20 big step for us to give up on PJM making a market because
21 they were almost there and the market was almost designed,
22 so we kept holding on. But there becomes a point where the
23 company can't continue to run these units absent at least
24 breaking even.

25 It's exactly as Roy spoke about. If you look at
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18895
DAV

149

1 the market, you're undercollected. As a generation owner,
2 you can't live undercollected a long time as a long-time PJM
3 member. And the fact that PS is responsible for the load
4 and PS is responsible for the generation, we probably kept
5 those units online longer than anyone else would and we
6 believe that we would put into our RMR contracts -- it makes
7 this a more pertinent issue that needs to be solved.

8 People say why can't LMP take care of this? We
9 were told LMP would take care of all locational problems and
10 generators would make money. The generators we're talking
11 about are in a constrained area, they run only when there's
12 transmission constraints. When you run a generator in a
13 transmission constrained area, it's cost capped. By
14 definition, the few hours these generators ran, they were
15 cost capped. You can't cover your costs at cost caps, it's
16 only covering the absolute marginal costs.

17 If the market truly had any deficiencies, if we
18 had demand response that would actually pay what it's worth,
19 that's wiped out because we have bid caps, the market can't
20 go over a thousand dollars. So units that run very little
21 at a time run for transmission constraints, runs against the
22 market at bid caps, they're not going to cover the amount.

23 In fact, two of the units we requested RMR status
24 -- and we'll talk about what that really means, requested
25 RMR status -- hadn't run in the last two years. So how
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18895
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150

1 people said why don't you collect your money on LMP, they
2 were never ordered on by PJM -- because you've got to
3 remember there's a 20 percent reserve margin in that area.
4 If you have cooler weather in the summer, you don't really
5 have the demands you had, you have good reliability in your
6 other units. Those units that have to be there for capacity
7 requirements can truly not run; hard to collect your money
8 in LMP if you can't run.

9 So for whatever reason, these units don't cover
10 their cost. We do a calculation that says these units are
11 losing X amount of money. Why would RPM help this? Because
12 that number, the amount that are not covering their costs
13 by, if we had RPM would be a bid into the capacity market.
14 We've now established, just as we did in our RMR filings,
15 that we need X amount of money to make these units viable,
16 and that would be our bid. That doesn't work like that now.
17 It's even worse than that. Under the existing rules of RMR
18 contracts, if you kept them, you need to change out.

19 The only option when we're losing money on these
20 plants is to write a letter to PJM saying I wish to retire
21 these plants. We made clear in the letter -- although it
22 doesn't matter much, we don't really wish to retire, we wish
23 to break even. We will do our share for reliability to keep
24 the units on, but we need to break even. But the rules in
25 PJM said you have to announce retirement.

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18895
DAV

151

1 The second set of rules that makes it worse is
2 when PJM gets that letter, they have to build transmission.
3 For the amount of money I needed to keep those plants open,
4 it may or may not be less than the transmission fix. And
5 they both may be more expensive than the demand side
6 response and we're not allowed to look at that. I must say
7 retire and they must build. RPM takes care of that.

8 The point in RPM is that we do not need to say I
9 need more transmission, I need more generation, I need more
10 demand side response. I let the market tell me what is the
11 least cost way of doing it.

12 The other thing I'd like the Commission to
13 remember is the problems in New Jersey, the local
14 reliability problems. Because people are not recovering
15 their costs are going to be the problems everywhere. They
16 hit New Jersey first at 5 cents a megawatt-day daily
17 capacity. They will hit everywhere else. Contrary to what
18 they say, you need to come up with a solution that solves
19 New Jersey so that you don't have these problems somewhere
20 else.

21 Thank you very much.

22 MS. COCHRANE: Thank you, Gary.

23 Since you went into an area of discussion about
24 your own RMR contracts, it's a pending proceeding --

25 MR. SORENSON: Don't say any prices, no numbers.

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18895
DAV

152

1 MS. COCHRANE: Aside from that, we'll put the
2 transcript into the docket in that proceeding, I would hope
3 for further discussion that we stay a little more general on
4 the RMR stuff.

5 Our next panelist is George Owens with Downes
6 Associates.

7 MR. OWENS: Thank you. It's a joy to be with you
8 today.

9 I'm going to try to share a little different
10 perspective, on purpose, than that which has been shared
11 before. As we heard this morning, there are a lot of
12 different proposals for what can be done to enhance the
13 capacity markets. Surely out of that will come a compromise
14 position that will be recommended by your group and I'm sure
15 will be adopted by PJM.

16 I want to speak today on a different area here --
17 and Steve spoke about it a little bit, but I want to
18 enhance on it as I begin, and that is transmission planning.
19 I'd like to recommend some reading to everybody here, all
20 the Commissioners as well. It's an excellent book and I
21 think it would clear one's brain for looking at these issues
22 and I hope you sense some of the humor in what I'm sharing.
23 But it's a very serious book. It's actually written by the
24 humorist Bill Bryson. It's called A Brief History of Nearly
25 Everything. I highly recommend you all read it in your
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18895
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153

1 spare time.

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18895
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154

1 What he attempts to undertake, is an evolution of
2 scientific thought in the last three or four hundred years.
3 It's amazing, as he documents that the debate that has gone
4 on in the development of everything from biology to geology
5 to astrophysics.

6 You see some amazing parallels to this process
7 going on today. I want to draw one, in particular.

8 He relates a situation in which, by the middle
9 part of this past century, researchers in geology knew that
10 something major had happened in the area of Yellowstone
11 Park, namely, that a major volcanic eruption had occurred in
12 prehistoric history, and it was of gargantuan size.

13 He also knew, this particular researcher at
14 Yellowstone, knew that it was not a regular dome volcanic
15 eruption like St. Helen's. It actually was an explosion of
16 the type that would have created a crater or bowl.

17 So he went about for quite a number of years,
18 something like ten to 15 to 20, working to identify the
19 epicenter and the crater. He spent a lot of time.

20 It wasn't until the development by NASA of our
21 space program, including satellites in orbit that enhanced
22 our military capabilities of collecting data, that he came
23 back with some pictures of the continental United States,
24 and they, fortunately, shared them.

25 When he looked at them, he immediately knew that
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18895
DAV

155

1 he had the answer. If everyone has read the book, you'll
2 know what the answer is.

3 The answer was that the crater he was looking
4 for, was the entirety of Yellowstone Park. It wasn't until
5 a photograph from space could be taken, that one could see
6 that a very bowl-shaped ring pattern enveloped the entirety
7 of the Park, so the problem he was looking for, was of such
8 size that he couldn't see the forest for the trees.

9 That's what I want to bring here this afternoon.
10 I don't mean that comment to be that everyone's blind. I,
11 instead, mean that I believe the problem is that large.

12 The problem that we are dealing with, that was
13 brought to light by what Gary just talked about in load
14 deliverability in New Jersey, actually as a problem that's
15 germane to all of the planning that has existed in PJM for
16 the last several decades.

17 It's a problem that Steve has said, very aptly,
18 that PJM is looking to try to deal with and enhance that
19 process and solve that problem. What am I speaking of?

20 What we saw in New Jersey was the tip of an
21 iceberg. I agree with Gary completely. It does cover quite
22 a large area. In fact, this week, if one has had the
23 opportunity to take a look at the LMP graphs, an I dropped
24 some off by your desk earlier before we began, of the PJM
25 marketplace.

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18895
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156

1 You will note that we have a new color on the LMP
2 screen. I really appreciate that PJM has selected it,
3 because now I can really say that things have turned black.
4 I'm glad I was able to make that comment before they changed
5 the color to eliminate that comment in the future.

6 But things have turned black; that is, the LMP
7 system is now showing us that the deliverability problem, as
8 of this past Tuesday, encapsulated all of the core area of
9 central PJM and PJM-South. Everything surrounding the
10 Chesapeake Bay, the Delaware Bay, all the way to the New
11 York border, was black.

12 It demonstrates the fact that we have a bigger
13 load deliverability problem than we're really talking about.
14 It's not going to be contained in what form or RPM model
15 that we adopt.

16 We must push on to go aggressively at the goals
17 Steve is speaking about. I want to come back and compliment
18 PJM in just a minute, again.

19 Another issue that I want to bring to light, is
20 that I differ with the other speakers to say that power
21 plants are being built in the wrong places. Power plants
22 are not being built in the wrong places; they're being built
23 in the correct places, where you have the confluence of
24 fuel, the transmission system to carry the power plant
25 output, and water resources for cooling, and predominantly
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18895
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157

1 fuel being the central ingredient.

2 You couple that with the fact that what almost
3 demographic people are saying now, is that by 2015 to 2020,
4 we will have some 30 million people in the central core
5 region of PJM Classic. That's a huge population that's
6 reached such critical mass that it's now drawing more
7 critical mass to it.

8 I hope it's not becoming the black hole that John
9 Sillin and I were discussing before we broke for lunch, but
10 it is reaching critical mass and is drawing more critical
11 mass to it. We're having a major migration of people back
12 to the East Coast, and we're having a large population
13 growth.

14 The result is that our demands for the electrical
15 system are reaching monumental proportions, just as Gary
16 said, so I appreciate him mentioning the actual numbers.

17 But the power plants that we need, are not just
18 going to be peaking plants or mid-merit plants. We're not
19 going to be able to carry those kinds of loads into 2020 and
20 beyond. We're going to have to carry them in the
21 traditional sense where we have power plants with the
22 momentum to carry the load and move the load, and those are
23 going to base-leg plants.

24 Because of the debate that's going on across the
25 street on the Energy Bill right now, we all know that energy

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18895
DAV

158

1 is in the top priority, and with the cost of energy and
2 fuels, there's going to be a drive, obviously, back to
3 native-born fuel services, and that's going to drive us back
4 to coal.

5 Obviously, your Staff saw that, and held a very
6 important conference, not just a few weeks ago, having to do
7 with that issue, and I really commend you for that. Those
8 are the kinds of discussions we're going to have to have.

9 Another subject matter that I'd like to broach is
10 that transmission is not expensive to build. It has to do
11 with the definition of "expensive."

12 If we're dealing with a small municipality and
13 we're looking at public works projects, "expensive" may be
14 framed in a term of \$1 to \$2 million.

15 If we're dealing with a state, it may be in the
16 hundreds of millions of dollars. If we're dealing with the
17 Federal Government and the size problems they face,
18 obviously, it's in the billions.

19 The problem that we face is in the building size,
20 but that doesn't mean, by nature, it's expensive. It has to
21 do with what the load impact is on the ultimate consumer.

22 That impact on the consumer, as you know by a
23 paper that I submitted for the last conference on this
24 subject matter -- and I resubmitted it with some updates --
25 pointed out that if you take a \$4 billion expenditure and
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18895
DAV

159

1 give a great rate of return to the transmission companies
2 and you give it the normal time for payback, you can pay for
3 it in tenths of a percent per kilowatt hour to every
4 ratepayer in PJM.

5 So, I agree with one of the earlier speakers -- I
6 believe it was Laurie. That said, we should socialize the
7 cost of major transmission. Why?

8 This is a very important issue. The "why" is
9 that we would all like to see the equivalent in the electric
10 marketplace, of the success story that we all well know, of
11 Sam's Club, the Walmart scenario and the like.

12 We would like to have a robust, open marketplace
13 where we can gain economic opportunity and have a diversity
14 of products. I want to point out to everybody, however,
15 that that marketplace would be totally impossible to run,
16 were it not for the socialized investment of every man,
17 woman and child in the continental United States to build
18 the Interstate Highway System, because that marketplace
19 could not possibly exist on the railroad system of the
20 1950s, or on the U.S. Highway and state highway systems of
21 the 1950s.

22 Before it could come to pass, it took the
23 development of an interstate highway system, and we are
24 going to have to build that. It's going to take the ten- to
25 15- to 20-year horizons to build the kind of networks we're
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18895
DAV

160

1 going to have to have, because, as Gary pointed out, and
2 Steve pointed out, our system was never built for that
3 purpose.

4 It was built for distribution and transmission of
5 power to load centers within vertically-integrated
6 utilities. Now that we want to use it as a superhighway, we
7 have to build such. It's time that big people step up to
8 big problems and we joining forces as the states, as the
9 FERC, as the individual transmission owners, and definitely
10 that's PJM and the Midwest ISO, and we tackle this problem
11 and not shy away from it.

12 And if we tackle it in a robust way, we'll find
13 out that it is not an insurmountable problem. It isn't
14 expensive; it just takes a lot of planning and a lot of
15 time.

16 Indicative of that, I want to commend AEP and the
17 fact that it was able to restart its project that it began
18 in the early '90s to build a 765 KV line from Southwest West
19 Virginia into Virginia.

20 Someone said, about the paper that I submitted
21 earlier, that my costs were too high. I appreciate that
22 compliment.

23 If you're going to try to deal with an issue
24 that's going to last ten to 15 years in debate, you want
25 your estimates to be high. That's what I tried to do.

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18895
DAV

161

1 The fact that AEP's cost is about \$270 million,
2 comes out to about \$3 million a mile. It's not surprising,
3 because they are not building it around Baltimore, D.C., and
4 Philadelphia where land prices are going to be a little bit
5 higher.

6 But I would say that my costs of around \$5
7 million a mile, counting substations and land procurement
8 and so forth, you're going to bracket it, and all I was
9 attempting to show in that study, was that we can honestly,
10 bravely look at the future, not shy away from it, and
11 embrace projects of the \$3 and \$ billion figure, not limit
12 ourselves to the \$1 billion that PJM is very proud of.

13 They've gotten started in six years. I'd like to
14 commend them, but I'd like to see us quadruple that effort,
15 and we really go after some projects of some size.

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18895
DAV

162

1 The western states have obviously embraced that
2 concept way before all of us got around to talk about it. I
3 appreciate the FERC, especially in showcasing the Frontier
4 projects, when you asked that at a transmission conference.
5 I thought that was a wonderful thing you did. I think it
6 helped PJM forward. In developing the mountaineer project
7 concept, I was pleased to see that a couple of the paths
8 that I suggested basically are mirrored in what Carl
9 suggested and had some excellent ones in addition.

10 It's that kind of creative thinking that's going
11 to draw all the parties together and I hope will end the
12 Civil War between the states, and I really mean that
13 sincerely, where one state says well I'm not getting the
14 lion's share of the advantage, therefore I don't want to be
15 included in the cost and they all say well if we plan
16 multiple projects everybody benefits and everybody can share
17 in the costs and it becomes exactly what we have in the
18 interstate highway system.

19 I wanted to commend PJM in my comments, because I
20 don't want anyone to think I'm being in any way critical.
21 What Audrey said in that earlier conference I thought was
22 extraordinarily true. She said are we looking for a strong
23 transmission system that by its design links distant
24 generation to load in order to address both economics and
25 reliability and accommodate an array of generation

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18895
DAV

163

1 alternatives from which load can choose. She then went on
2 to say in many ways the Energy Policy Act of 1992 answered
3 this question in favor of the strong superhighway to support
4 a competitive generation industry. I don't think that could
5 have ever been said more succinctly, and I really commend
6 her for that.

7 In addition, what Carl said later in the next
8 conference that you held, he pointed out that there have
9 already been notable examples of this kind of regional
10 planning, of the type Steve is now talking about and Carl
11 mentioned, namely that the 500 kV transmission system in PJM
12 was constructed through a collaborative planning effort and
13 a collaborative partnership.

14 He went on to explain that other projects had
15 been done in a similar way in the history of our nation. In
16 fact, I'd like to go on the record in saying that what I'm
17 talking about is nothing new and I can't claim any pride in
18 ownership, because it's how our power industry in a major,
19 major way was constructed in the 1950's, 60's and 70's and
20 we really need to go back to those days of solid
21 investments.

22 And some would say well, George, that flies in
23 the face of a competitive market. Quite the contrary. It's
24 the basis of a competitive market. The better the highway
25 system we have, the better the competition will be and we'll
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18895
DAV

164

1 finally achieve what we all enjoy today under the banners of
2 Wal-Mart, Target and some of the others.

3 MS. COCHRANE: George, can I ask you to
4 summarize?

5 MR. OWENS: Please.

6 Where I was going was exactly that. That was my
7 closing statement. What I said earlier in my comments, I
8 want to reiterate. I would like to see the Federal Energy
9 Regulatory Commission lead an investigation of all these
10 factors -- you're certainly beginning to do that. I'd like
11 to see you all encourage a convocation of all the state
12 commissions to work together. I'd like to see you direct
13 the PJM to form a separate long-term bulk transmission
14 system planning process not limited to RTEP and economics,
15 but actually a separate process that's named the bulk
16 transmission interstate planning process and then, in the
17 long run, I would like to see that the expansion of the
18 interstate bulk transmission system become the bedrock of
19 our industry and everybody accepts that. Because in the 15
20 or so years it will take to build such lines, our industry
21 will, in an evolutionary way, develop and we will have
22 markets come to that, not markets shy away from that.

23 Thank you.

24 MS. COCHRANE: Thank you all for your comments.
25 Just as a procedural matter, I'm going to ask

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18895
DAV

165

1 that the transcript be put into ER05-644, which is the
2 proceeding you alluded to, just to be on the safe side.

3 My first question is to you, Gary. You
4 specifically said that you're referring to RPM fixes a
5 variety of things. One of the purposes -- or the main
6 purpose of this conference is to talk about capacity markets
7 in general and different constructs. And the previous
8 panel, we had three different alternatives proposed to us or
9 presented to us, two in addition to RPM.

10 And I just wanted to ask you, after listening to
11 the descriptions of these other alternatives, are you saying
12 that the RPM is the only way to go or could you more
13 specifically talk about which elements of the capacity
14 market you feel are necessary?

15 MR. SORENSON: It's a question that keeps coming
16 up: do you want location or do you want forwards? If you
17 get the one, don't waste your time, you need both. PJM's
18 proposal fixes everything. The difference between PJM's
19 proposal and PPL is not that large. I would say you have to
20 listen back when Brian was on the panel. Investment people
21 are hung up, they won't invest without a contract or they
22 won't invest without a surety of where we're going.

23 I think once they know that there is going to be
24 a demand curve and people who do the economics, yes, they're
25 going to have one price, you know, four years out, so they

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18895
DAV

166

1 have one through four years of price, but they're going to
2 have a way to model what is going to be in year five, year
3 six and year seven. They can do that with surety.

4 I honestly don't believe -- although PPL does --
5 that you need a bilateral contract to set the price. Once
6 you have a good capacity construct as in the PJM model, I
7 think you're okay. The difference isn't that big. The ODEC
8 coalition proposal where you can continue to use RMRs and
9 where it's stated in his notes don't worry about the New
10 Jersey problem, I think is the absolute wrong way to go.

11 MS. COCHRANE: David?

12 MR. MEAD: I'd like to follow-up on the
13 discussion that happened earlier with Mr. Herling and Mr.
14 Baker. If I'm understanding one of the AEP concerns, it is
15 an aspect of the demand curve or the variable resource
16 requirements that for a long time that AEP has operated
17 under a presumption that it's going to need to procure 15
18 percent reserve margin and, under RPM, you may have to
19 procure more from year to year depending on what the nature
20 of the demand curve is in the intersection of the supply
21 with the demand curve. I didn't hear a concern about the
22 four-year forward procurement.

23 What I'm wondering is would AEP find it
24 acceptable to show PJM four years in advance that it's met
25 whatever the fixed requirement is and, if it did, it would
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18895
DAV

167

1 not need to participate any further in the demand curve
2 process. If you agree with that, does PJM see any
3 disadvantages to basically letting anybody opt out who can
4 show four years in advance that they've met whatever the
5 fixed requirement is.

6 MR. BAKER: I'll start, and Steve can respond.

7 When we look out, we look further than four
8 years. The devil is always in the details. Let's just use
9 an example. Let's assume I'm going forward with the IGCC
10 plan in Ohio. It gets approved by the Commission and we're
11 going forward. What is the criteria you look at for whether
12 you've met that four-year cycle? Do we have contracts? Do
13 we have a contractor in place? Have we broken ground? All
14 of those things.

15 If we're in a normal -- I'm going to show you my
16 building plan and it falls within that picture that's fine,
17 yes. We're willing to show that far out that we're going to
18 need it ourselves with our own resources. It varies. That
19 timing issue and the amount of details varies on the type of
20 capacity you're building, obviously. Peakers have a shorter
21 lead time. You may not have as much contractually set up,
22 but a commitment to meet that. The answer is yes, but we'll
23 have to see how the stakeholder process in PJM structured
24 the proof of those requirements.

25 MR. HERLING: Seeing as how about half a dozen

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18895
DAV

168

1 transmission-related questions were punted to me this
2 morning, I think I'm going to leave this one for Tom Welch
3 and the next panel.

4 (Laughter.)

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18895
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169

1 MR. SINGH: I just want to make sure I
2 understand, Gary. If I do the auction four years ahead,
3 people will see that price and be able to figure out prices
4 for Years 5, 6, and 7.

5 On the other hand, if I do it one year ahead,
6 they won't be able to see that price and figure it out for
7 Years 2, 3, and 4.

8 MR. SORENSON: The further out it is, the more
9 stable it is. I don't believe that going back to one year
10 changes it. It doesn't change the economics of building,
11 but when you come back to one year, where PP&L was, you're
12 taking away a lot tools from PJM.

13 Four years out, if we had this process four years
14 ago, when I put my units in there, plenty of time to do
15 something, one year out, no time for the reliability.

16 MR. SINGH: Like you said yourself, if you have
17 PJM put in a demand curve, market participants state that
18 and figure out things for the subsequent years.

19 MR. SORENSON: That's the economic piece. PP&L
20 is very concerned about the economic piece, but there is a
21 physical reliability piece. If the markets guess wrong one
22 year out, and we do guess wrong, every plant we built wasn't
23 useful, and we make mistakes.

24 In one year when I find out, I'm not going to
25 build that plant or I run out of money, and PJM can't keep
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18895
DAV

170

1 the lights on. Yes, the market worked and they had nice
2 bilaterals and the trading people liked that, but one year
3 is not enough time for PJM.

4 MR. SINGH: That's like saying that control is
5 better than trust.

6 MR. SORENSON: No, it's a physical limitation.
7 PJM may trust me completely, but if something goes wrong
8 with only year, he has very few options.

9 MR. SINGH: The question, really, that I have for
10 Steve -- you've said, on granularity, we need to be
11 consistent on generation and transmission. And people made
12 the point earlier, I think, on one of the panels, that the
13 deliverability construct in PJM wasn't being applied
14 properly or wasn't handling this issue; is that correct?
15 Was there a granularity problem?

16 If so, is New York's attempt to apply that within
17 the zones, going to be different or the same?

18 MR. HERLING: There has not been a granularity
19 problem. We look at the PJM system, in varying degrees of
20 granularity, and can't identify problems from segments of
21 the system as small as a couple of thousand megawatts, all
22 the way up to 20,000 or 30,000 megawatts in the Eastern MAC.

23 The issues raised this morning, that, five years
24 ago, we did not identify these problems, because we had no
25 possible way to anticipate a few thousand megawatts of

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18895
DAV

171

1 generation retirements.

2 If I had asked Gary five years ago, what do you
3 think of the chance of these generators retiring, first of
4 all, he probably wouldn't have answered me, and, if he did,
5 he would have said, no, they'll still be there.

6 So, there's nothing wrong with the deliverability
7 construct, other than the fact that it cannot use a crystal
8 ball to anticipate where those retirements are going to take
9 place.

10 As to the granularity, we have the ability to
11 look at all of Public Service or half of Public Service or
12 all of New Jersey.

13 The key to the granularity is, if it's a New
14 Jersey problem, the transmission solution or the generation
15 solution, both have to compete. They both have to be able
16 to resolve the problem.

17 If we looked at Eastern MAC, every time there was
18 a deliverability problem anywhere in Eastern MAC, we said,
19 it is an Eastern MAC problem. We could site generation all
20 over Eastern MAC and not resolve the problem, because we
21 didn't put it in one corner or Northern New Jersey where the
22 actual problem happened to be.

23 So, granularity gets to what is the magnitude of
24 the problem? Is it really a local issue or is it a New
25 Jersey issue or is it an Eastern MAC issue?

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18895
DAV

172

1 So, the transmission solutions and the generation
2 solutions can actually compete and potentially demand
3 solutions, can compete to resolve the problem. They all
4 have to be able to resolve that problem similarly, for them
5 to be able to compete.

6 MR. BANDERA: Steve, to follow up on that, Ed
7 Tatum in the last panel, was talking about, instead of using
8 the four-year forward, using a probabalistic approach to
9 model what's coming and coming out.

10 What you're saying is that this probabalistic
11 model may not be that useful, or not possible to develop as
12 an alternative to the four-year forward.

13 MR. HERLING: We use a range of probabalistic
14 tools now in the planning process. What really needs to be
15 done -- and this is the task ahead of us at the moment -- is
16 to identify what are the criteria, above and beyond the
17 bright line reliability criteria? What are the criteria you
18 want to use, so that the transmission system supports a
19 robust, competitive market?

20 If we choose, for example, to have criteria
21 around at-risk generation, which people are suggesting,
22 there are many, many scenarios.

23 You can choose related groups of generators that
24 may be at risk or have different parameters that suggest
25 they're at risk. At the end of that analysis, you have to
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18895
DAV

173

1 decide what to do with the results.

2 That's more scenario-planning; that's not
3 probabalistic. We know that there are lots of scenarios,
4 but we have no reason to assume that one is any more
5 realistic than any other.

6 So you have to decide what are the criteria;
7 against what will we choose to build transmission? We have
8 probabalistic tools today that we use for load
9 deliverability and generation deliverability.

10 Now, we have to decide what criteria we want to
11 use, and that is the task we have, moving forward.

12 MR. SINGH: Let me follow up on that. Even in a
13 deterministic sense, there's been a very interesting
14 development in New York on looking at what justifies a
15 transmission project, so there is a measure of redispatch
16 cost in the system and there is a measure of congestion
17 rents. In 2003, in New York, redispatch rates were \$85
18 million. Congestion rents, on the other hand, were, I
19 think, \$560 million.

20 To give you an extreme example, if you had 1,000
21 megawatt line, and you had ten megawatts of congestion on
22 that and you had a \$10 credit cost, the redispatch cost
23 would be a hundred; congestion rents would be \$10,000, very
24 different figures.

25 What does PJM look at? If you look at redispatch

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18895
DAV

174

1 costs, what are they?

2 MR. HERLING: Today we have a very limited
3 element of our planning process that looks at what we refer
4 to as the un-hedgeable congestion component.

5 Moving forward, you know, we're looking to expand
6 our focus and to determine, as you go beyond that. Maybe we
7 need to adjust that component. We need to look at the much
8 broader question of what does it take?

9 George's proposal and the one we've been looking
10 at with Mountaineer, what does it take to support a robust,
11 competitive market? Mountaineer is a process to answer a
12 question and to determine what transmission would be
13 required, and, is that a good thing to do? Does it make
14 sense economically?

15 What tests do we have to develop to make that
16 decision? So there's a lot of work to be done to answer the
17 very question you're raising. What are the criteria? What
18 are the tests that help you make the decision as to what
19 needs to be built, and what does not make sense to build
20 with respect to a robust, competitive market?

21 MR. SORENSON: Can I add to that?

22 MR. SINGH: In the case of New York, the un-
23 hedgeable component is \$200 million, off the top of your
24 head?

25 MR. SORENSON: We have to do that to make sure

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18895
DAV

175

1 you end up with the least-cost solution. It's very easy to
2 see that amount of congestion.

3 Realize that when you relieve that congestion,
4 you have to redispatch West of New York. Now you're raising
5 prices for some people and lowering for others.

6 That's where you've got to talk about how much do
7 you want to socialize, because it's -- you can't just make
8 the congestion go away. You have to not redispatch to
9 replace what's shut down in the East? These are complicated
10 issues.

11 MR. SINGH: In that particular example, the
12 payments made by consumers as a whole, actually go up,
13 because there's more load outside of New York City, so that
14 sort of goes to George's point on some socialization.

15 MR. LEVIN: John Levin, Pennsylvania Commission.
16 George Owens brought up a number of interesting issues that
17 arose out of the West Virginia Technical Conference. I was
18 actually in Washington on that day and I wasn't able to
19 attend.

20 I got a report of the proceedings about a week
21 afterwards. We were somewhat surprised to see the
22 announcement of Project Mountaineer, which we understand to
23 be more of a concept than a defined process.

24 Also, the concept that the Energy Policy Act of
25 1992 had decided on the long lines versus a distributed kind

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18895
DAV

176

1 of network model.

2 But these are issues that are, to some extent,
3 dealt with the RPM process. The RPM design assumes that
4 transmission can be brought in as one of the market elements
5 in balancing transmission load response and to get an
6 optimal kind of investment mix.

7 The Project Mountaineer process seems to imply
8 that we need to decide in advance that we should bring
9 distant generation by wire to distant load. Steve, how are
10 these two kinds of concepts going to be integrated by PJM or
11 by someone else, if that's what's going to happen?

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18895
DAV

177

1 MR. HERLING: Remember that there are a number of
2 very large coal projects currently in our interconnection
3 queue in Kentucky, West Virginia, Southeastern Ohio. We
4 have to, through our generation interconnection process,
5 determine what it will take to integrate them under our
6 current reliability construct. The obvious question is does
7 it make sense to go beyond what would otherwise be required
8 based on our current reliability rules, are there
9 opportunities to enhance the performance of the market, and,
10 do those opportunities make sense? All those questions have
11 to be answered. We're not presupposing what the end result
12 will be, but it seems fairly obvious that there is an
13 opportunity here to look beyond our current vision of
14 planning and, in particular, beyond our current vision of
15 economic planning.

16 We know that there is a certain amount of
17 congestion across our transmission system that these kinds
18 of lines would resolve. That alone may not justify the
19 lines. We know that there is a deliverability component
20 with the generators. We know there's a deliverability
21 component with the load in eastern PJM. All of these pieces
22 and perhaps more need to be taken and looked at together so
23 that we develop a holistic solution to potentially a number
24 of issues, rather than look at each one in a silo: look at
25 the load deliverability issues in New Jersey and find a

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18895
DAV

178

1 solution to that problem, look at the integration issues for
2 these generators and solve that problem, look at the
3 congestion and solve that problem when we have the
4 opportunity potentially to put an aggregate solution, a
5 holistic solution on the table. But, before we do that, we
6 have to challenge our historic vision of economic planning
7 in particular and to determine whether or not it makes sense
8 to go beyond what we have done traditionally in support of
9 the market.

10 MR. LEVIN: If I recall correctly, part of the
11 concept was that the existing RTEP process really only looks
12 maybe five to six years out, and we needed a process, a more
13 holistic process, that really looks 10 years out. If you're
14 looking 10 years out, aren't you doing that in the absence
15 of any kind of meaningful economic signals, even with RPM in
16 place?

17 MR. HERLING: The current planning process does
18 two things: we look five years out using our reliability
19 criterion as a bright-line test, you pass or you fail, if
20 you fail we have to build transmission. Those are the kinds
21 of upgrades we integrate into the RTEP and our board
22 approves today. Clearly five years, as I think Andy
23 mentioned earlier, five years, we can build a lot of things
24 but we can't build 500 kV or 765 kV transmission in five
25 years. Ten years is questionable. It may take 15 years.

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18895
DAV

179

1 We have historic examples that took longer than that.

2 The potential change in the planning horizon was
3 not specifically related to Mountaineer. That was a
4 response to a wider range of concerns raised by our
5 stakeholders that go back probably six or nine months ago,
6 somewhat arising out of the generation retirement issue.
7 The question was, since we were unprepared for these
8 generation retirements to a certain degree, what changes
9 should we make to the planning process? Should we be look
10 at at-risk generation? Should we be looking at a longer
11 planning horizon?

12 Clearly a longer planning horizon brings with it
13 uncertainties that are difficult to deal with in the five
14 year horizon and are going to be more difficult in the 10
15 year horizon. That's the challenge of this process, is to
16 identify what are all the moving parts and how do they fit
17 together and how do you develop a planning process that
18 works with a 10 year horizon, that works with a different
19 vision of economic factors and still provides for
20 reliability and gets projects built in a timely fashion.

21 MR. LEVIN: I guess finally, when you do look
22 that far ahead and you use all these issues with that kind
23 of variable data, aren't you in some sense picking winners
24 or losers in the generation, transmission, and load response
25 markets by the way that you finally decide to configure the

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18895
DAV

180

1 network?

2 MR. HERLING: Those are factors that I think need
3 to be considered as we look to potentially expand our vision
4 of economics, to understand how the decisions we make have
5 the possibility to affect individual stakeholders and to
6 create winners and losers. That's just something we're
7 going to have to take into consideration in the design of
8 that process.

9 MR. BAKER: I'd like to comment for a minute.
10 There was a lot of discussion just then on the holistic
11 approach. That was within our planning process at PJM. But
12 I think when we think of transmission, we have to think of a
13 holistic approach that also takes into account siting and
14 takes into account a pricing proposal that's regional in
15 nature.

16 I was interested to hear George's comments on the
17 way to price certain transmission on a socialized basis. I
18 don't think I necessarily agree with his analogy on the
19 highway system, that it is purely a socialized basis. I
20 would assume that truckers think they pay more for the
21 highway system than does the elderly grandmother who takes
22 her car out only on Sundays to go to church. So it's a
23 combination of socialization as well as usage.

24 But I think we have to look at all three things.
25 We have to look at the planning process, we have to look at

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18895
DAV

181

1 the siting, and we have to look at pricing as a mechanism to
2 get needed transmission to be built.

3 MR. LEVIN: Craig, I'm a little surprised to hear
4 you say that, since AEP is trying to socialize some of its
5 backbone on us right now.

6 (Laughter.)

7 MR. BAKER: Well again, I don't think we can talk
8 about specifics.

9 (Laughter.)

10 MR. BAKER: We can take this off-line.

11 (Laughter.)

12 MR. OWENS: John, I'd like to respond to what you
13 asked because I think it's an essential ingredient. As you
14 look long-term, I think what Steve is also saying is that
15 you also have to look at what kind of generation mix is
16 going to be necessary. And no one is precluding in a
17 project that might take 15 years to get online that you
18 would attempt to put peakers or mid-merit units out of
19 business.

20 What I was trying to say is we have a backbone
21 power requirement that's only going to be met by baseload
22 plants. Baseload plants cannot possibly reach the market
23 without the help of large-scale transmission. It's a matter
24 of a holistic approach, integration resource planning, that
25 works so far out that it allows the market to oscillate and
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18895
DAV

182

1 do its job and converge around those ultimate solutions. I
2 don't think in the long run the addition of the kind of
3 transmission that Mountaineer would envision or that I would
4 even propose would negate construction of generation. I
5 think it would incent it.

6 I estimate there might need to be as many as 20
7 substations at various interconnect points along those
8 routes. Every time you have a high-voltage bulk power
9 substation, you've given birth to a new nodal point where
10 people can connect and transact business in all kinds of
11 ways. So I think it would incent generation, not diminish
12 it.

13 MR. LEVIN: Thank you for those comments. Please
14 don't interpret my question as representing the formal
15 position of my commission. Thank you.

16 (Laughter.)

17 MS. COCHRANE: I have a clarification question
18 for Steve. When you talk about Project Mountaineer as being
19 a process, I was wondering if you'd comment on how the role
20 of RFPs would be considered. I'm assuming you would do this
21 holistic study and then put out an RFP for construction of
22 different elements. How would merchant transmissions versus
23 transmission owners compete to construct those identified
24 areas, I guess?

25 MR. HERLING: One thing you've got to remember,

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18895
DAV

183

1 Mountaineer, as I said, is a process. There are a number of
2 tracks we have to follow to make this come together. The
3 business issues identifying transmission elements that are
4 viable is going to be a challenge. Figuring out how they
5 fit together and how much capability you derive is a
6 challenge. These are engineering tasks that we understand
7 fairly well and we can set people to and move forward.
8 There are a number of business issues that have to be
9 thought through and a lot of decisions that are going to
10 have to be made.

11 The ones you raise are certainly all on that
12 list. We do not yet have answers to those questions.
13 Clearly, we -- and Carl's comments about Mountaineer
14 suggested that some form of consortium would be necessary,
15 just by the sheer magnitude of the project. When we use the
16 word "consortium," we harken back to the development of our
17 500 kV system in PJM built by groups of transmission owners
18 who came together with a common purpose at a given point in
19 time. Some form of business structure is going to have to
20 be put together but we do not yet have at this time a firm
21 idea as to what that might be.

22 COMMISSIONER BROWNELL: Can I make a comment?

23 I'd like to see as part of the fix that we I
24 think agreed to, or certainly I agreed to this morning, on
25 the transmission planning process, I'd like to see us begin
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18895
DAV

184

1 to answer those questions. You have a number of merchant
2 propositions that have been languishing. PJM does not
3 appear to welcome outsiders into the process. When you say
4 "a consortium," which we certainly encourage -- we believe
5 public power, co-ops, and private investors, as well as IOUs
6 could be involved. But I think the business structure
7 itself ought to be determined by the value proposition that
8 the investment community sees in it.

9 To predispose to a consortium is a big project.
10 They're people with a lot of money -- we've seen some out in
11 the market recently. I'd like to see PJM kind of work on
12 what is that process going to be, what are you going to
13 consider, how open is it going to be, will there be an RFP
14 process -- by "RFP," I don't necessarily mean the lowest
15 bidder. Are you looking for solutions that include new
16 technologies?

17 We just saw a wonderful project with Excel and 3M
18 where they doubled their capacity without having to increase
19 the number of towers at about the same price the old
20 technology would have taken. I think we need to start
21 hearing that. It's hard to get excited about Mountaineer
22 when we just kind of don't have any concept other than a
23 kind of piece of paper in their hand.

24 So I think for all of us, including potential
25 consortium members, to get comfortable, we need to

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18895
DAV

185

1 understand that the rules are going to be more equitable.
2 We heard this morning that the rules for transmission are
3 vague, unclear, the process is not anywhere near as clear as
4 for generation. So I think, as everyone has identified at
5 one point or another, that capacity market issues are also
6 related to transmission issues. We'd better start
7 expediting these kinds of decisions.

8 MS. COCHRANE: We'll take one more question and
9 then break for the next panel.

10 MR. KATHAN: I wanted to follow-up on, I guess,
11 the task that you added, Steve, to yours and the list of
12 five things, initiatives. Kind of following up on what Nora
13 was asking about, the openness of the process, we talked
14 about the near-term New Jersey issue. What is PJM doing to
15 deal with these retirement issues and, I guess, the black
16 that's on these graphs. What are you planning on doing?
17 What are the processes?

18 MR. HERLING: Mike Kormos, who is our vice-
19 president of operations, is working with a team internally
20 in PJM to essentially get out to all of the various
21 stakeholders to try to look at where the opportunities are
22 to resolve these problems in the short-term. Obviously we
23 have quite a list of things already in process. We have a
24 number of shorter-term transmission fixes which are already
25 well underway; some have already been implemented for this
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18895
DAV

186

1 summer. But we are basically out talking to stakeholders,
2 the BPU, trying to identify what the potential opportunities
3 are to resolve these problems, understanding that the RPM
4 has been delayed and we do need to take some actions in the
5 meantime. But we've dedicated a lot of resources at PJM to
6 getting out and trying to work through these issues with the
7 local stakeholders and identify some opportunities.

8 MR. KATHAN: Will you be doing RFP's and things
9 like that and bring in possible new technologies Nora was
10 referring to?

11 MR. HERLING: The new technologies, clearly we
12 are looking at those in a number of areas within the
13 planning process and looking for how we will be better able
14 to integrate new technologies in general into the planning
15 process in the future. That is a task we have been
16 challenged to move forward at PJM. We're looking at all
17 possibilities within New Jersey and we're trying to advance
18 the solution set as quickly as we possibly can.

19 MS. COCHRANE: Thank you very much to this panel.
20 We appreciate your comments and discussion.

21 If we can try to real quickly switch over to the
22 next panel. I know there will be a lot of discussion with
23 the next panel, too. Let's just take five minutes, please.

24 (Recess.)

25 MS. COCHRANE: If we can all start to take our
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18895
DAV

187

1 seats, please. If we can go ahead and start with our next
2 panel, please. Our next panel is on the procurement side
3 issues of the capacity market. This should be a very
4 interesting discussion, based on what we've had so far.
5 We're going to be covering in more detail demand curve and
6 demand response in particular, forward obligations versus
7 procurement, a lot of issues that have already come up so
8 far today.

9 Since this is a pretty large panel, we'd like to
10 have time for Q&A and finish up today so that we can do some
11 wrap-up. I'll just remind people, if you all can keep your
12 comments, your prepared statement anyway, to like around
13 five minutes, that would be great.

14 Our first panelist is Tom Welch, Market Strategy
15 with PJM. Thank you.

16 MR. WELCH: Thank you very much. It's a pleasure
17 to be here.

18 I want to first take a shot at actually answering
19 John Levin's question to Steve about the relationship
20 between transmission planning and the capacity market
21 envisioned by RPM. Both are essential.

22 One way of looking at the relationship is that
23 each process informs the other. Looking long-term helps you
24 assess what the economic challenges and opportunities will
25 be as the system matures. Just as the data points made
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18895
DAV

188

1 available through RPM will provide the requisite certainty
2 for project investment, those same data points will also be
3 critical inputs to the transmission planning econometrics --
4 econometric modeling.

5 Similarly, where that long-term transmission
6 planning process identifies transmission projects with long
7 lead times that are likely to bring substantial benefits and
8 are, therefore, likely to be built, those data points
9 themselves will inform RPM. I don't see this as an
10 either/or situation at all. I think they're important
11 complements to one another.

12 As you've certainly heard today, there's no
13 shortage of ideas about how to fix the current capacity
14 market, and virtually every element of every proposal
15 requires balancing a variety of interests. What RPM does,
16 while it probably doesn't satisfy any particular interest as
17 that particular interest would most like to have it
18 satisfied, it does do a good job of balancing and, in
19 particular, accommodates a number of specific items which I
20 think are important to the market and some of the
21 participants.

22 The first is bilateral contracting. Andy's
23 already covered a great deal of this, so I'll be quite
24 brief. Obviously, bilateral contracting is an important
25 tool in the market, but it's not actually the only tool.

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18895
DAV

189

1 It's not an end in itself. It's a way of allowing
2 participants to hedge themselves from their positions. So
3 in a sense, what we envision with RPM is that some aspects
4 that might otherwise be done in bilateral markets would now
5 be accomplished through RPM, but there are a whole set of
6 additional kinds of bilateral contracting that would be made
7 available.

8 Frankly, the greater forward price predictability
9 that RPM is likely to stimulate or is likely to create -- we
10 think likely will stimulate bilateral contracting. You've
11 already heard today that the current market has the risk
12 parameter so broadly set that there's actually very little
13 bilateral contracting for any point of time. We think both
14 buyers and sellers in the bilateral market will have an
15 interest in hedging the uncertainties that remain under RPM,
16 buyers may be uncertain about load and prices beyond the
17 auction horizon, sellers might want to achieve greater
18 revenue predictability and stability.

19 The point here again is not that the RPM will
20 produce the greatest volume of bilateral contracts, but
21 there's certainly no reason to believe that RPM is going to
22 constrain bilateral contracting to levels that are
23 unacceptable for the market and, indeed, will create a whole
24 new set of opportunities for bilateral contracts because of
25 the increased certainty it provides.

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18895
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190

1 A second element is the relationship between this
2 and various formulations of LSE activities. Here I don't
3 think RPM is going to interfere with any of the load-serving
4 entity structures or, indeed, any of the forms of regulation
5 because it doesn't really change structurally what those
6 entities are doing. I think it's an input to what they
7 would be selling, but it doesn't deprive them to any great
8 extent of the products they're selling.

9 Indeed, by providing greater information about
10 future prices and supply LSEs in the competitive market may
11 be able to offer longer-term products and stimulate
12 competitive activities. We see this as a plus. LSEs, under
13 traditional regulation, will be able to evaluate their
14 procurement more effectively because the future costs of
15 supply will be more transparent. So we see this as a
16 positive element for LSEs.

17 Provider of last resort has a few dimensions.
18 One I want to touch on briefly. There was a description a
19 couple of times this morning that somehow PJM becomes a
20 provider of last resort. I don't think that's true in any
21 sense. PJM runs an auction today; it would run an auction
22 under RPM. What PJM would do with appropriate consultation
23 is set the slope and placement of the demand curve, the bid
24 set, the price; the load pays the price, either in their
25 bilaterals or to the extent they're deficient in the auction

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18895
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191

1 price. So PJM doesn't become a POLR.

2 Another dimension is, provider of last resort
3 service cannot do what RPM is intending to do, they're not
4 close substitutes. For one thing, provider of last resort
5 typically only has a portion of the market, so it's not as
6 broad as RPM needs to be. On the other hand, RPM isn't a
7 substitute for POLR because it doesn't provide the full
8 range of products, it's not a retail product.

9 So while I think they can and do work well
10 together, they are really just different kinds of products.
11 They attempt to achieve different things. There may be some
12 fuller impact on supply. But it's not the kind of long-term
13 persistent market-wide pricing we think is essential for the
14 market as a whole.

15 Next, with respect to self-supply, again, RPM
16 permits load-serving entities to self-supply their capacity
17 obligations. In a sense, it functions very much like a
18 bilateral. If you cover your obligation through self-supply
19 or through bilateral contract, you're only exposed for the
20 difference between what you expected to have as load and
21 what you actually had as load, and you're paying the auction
22 price for the difference. I think it's very compatible with
23 the self-supply approach. RPM would provide important price
24 information to LSEs who are considering self-supply and,
25 indeed, for state commissions to evaluate whether some
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18895
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192

1 option which an integrated utility presents to them makes
2 sense to them in terms of price.

3 We, PJM, are evaluating various ways to integrate
4 the activities of LSEs who are under integrated resource
5 plans into RPM, but I'll say at this point it's certainly
6 not obvious that a complete carve-out for a vertically-
7 integrated utility is going to be the most efficient or
8 effective way to address the system as a whole or even for
9 that utility's territory. I think we need to be able to
10 understand and figure out how to integrate it successfully.
11 I don't think a complete carve-out really makes sense.

12 Finally, the last item on demand response, as
13 with bilaterals, RPM would change the opportunities for
14 demand response. That's not the same thing as saying they'd
15 be reduced or of inferior quality. I think one thing we've
16 heard from quite a number of demand response entrepreneurs
17 is that the forward signal is the one thing missing right
18 now from their ability to put together a successful business
19 plan. RPM specifically incorporates the ability of demand
20 to participate in the market and actually capture an
21 additional piece of the market that they bring. From that
22 standpoint, I think it's a plus.

23 It is true that RPM in any successful capacity
24 model will have the effect to some extent of reducing price
25 volatility that might dampen the market for some form of

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18895
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193

1 demand products. It's going to create a new set of business
2 opportunities by again providing revenue opportunities that
3 require longer gestation and development.

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194

1 In conclusion, I think perfect harmony in RPM
2 among the various interests and participants, is very
3 unlikely, simply because there's a wide variety of economic
4 interests at stake.

5 Greater efficiency and predictable reliability is
6 not going to affect all equally, and really requires a
7 commitment to the long-term health of the system and a long-
8 term view of customer costs.

9 While PJM is committed to continuing to work with
10 state commissions and this Commission and market
11 participants on all of these issues, it does seem to us that
12 the RPM construct is sufficiently developed and understood
13 by the parties at this point, in part through this
14 Conference, to warrant formal consideration by FERC on a
15 fairly near-term basis.

16 I think further delay is unlikely to raise
17 additional issues that produce new insight, but would risk
18 repeated episodes of the shortages we've seen, that could
19 only be addressed through less efficient or more expensive
20 solutions. Thank you.

21 MS. COCHRANE: Thank you for your comments, Tom.
22 Our next panelist is Ben Hobbs from Johns Hopkins
23 University.

24 MR. HOBBS: Thank you very much for inviting me
25 to talk this afternoon. I'm going to be telling you a

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18895
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195

1 little bit about an analysis that we at Johns Hopkins
2 performed for PJM, a simulation analysis of the performance
3 of the RPM construct and alternative demand curves.

4 I have to preface things and say that everything
5 I say here, all the opinions, are mine, and so are all the
6 mistakes. They don't necessarily represent the opinion of
7 PJM.

8 I think you have a set of overheads in front of
9 you. I'm just going to skip lightly and highlight some
10 major points, and, I hope, keep within my five to seven
11 minutes.

12 On the second page, I show just a couple of
13 examples of different demand curves. The one on the right
14 represents the situation now where the deficiency payment
15 represents the maximum that a load-serving entity would be
16 willing to pay.

17 MS. COCHRANE: Hold on just a second.

18 MR. HOBBS: I apologize to those in the audience
19 that I got off the red-eye this morning and didn't make
20 enough copies. There are some copies sitting on the table
21 in the back.

22 But it looks something like this.

23 MS. COCHRANE: Got it. Thank you.

24 MR. HOBBS: Slide 2 shows a couple of different
25 demand curves in the abstract. Basically, the situation

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18895
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196

1 that PJM is now in, is on the right, with a vertical demand
2 curve.

3 What's being proposed is putting some slope into
4 it, just like in New England and New York, as you see on the
5 left.

6 My hypothesis, which we tried to test for this
7 model, is that adding slope to the curve would lower the
8 variation in revenues that generators receive, and if you
9 believe that generators are more likely to invest when
10 there's less risk or they prefer less risk, that, in turn,
11 will that or will that not result in more investment and
12 what will happen to consumer costs?

13 The hypothesis is that the cost of capital is
14 lower, then, ultimately, the cost to consumers will be
15 lower, and that's what we tried to simulate here.

16 Going to the third overhead, it just shows the
17 questions we tried to address, how the different curves
18 affect the stability of the market, the ability to meet
19 reserve requirements, and what are the costs to consumers?

20 This is really important: how robust those
21 conclusions are to different assumptions. I cannot get into
22 the head of generators to know what their degree of risk
23 aversion is, or how they forecast energy prices or ICAP
24 prices or anything else.

25 My whole philosophy was to have as simple a model

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18895
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197

1 as possible, that captures the main features we're trying to
2 get -- risk aversion, forecasting, prices, different streams
3 of revenue from energy and ancillary services -- then look
4 at different curves over a whole range of possibilities, and
5 say, are there certain curves that consistently do better
6 than others?

7 There's no single set of assumptions that are
8 right. This is not a predictive model; rather, this is a
9 model to show what the implications of different assumptions
10 about generator behavior are.

11 It does turn out that there are some robust
12 conclusions. In a nutshell, the conclusion is, if you go
13 from a vertical demand curve to something with a slope, you
14 do lower risk to generators, you do increase entry, and you
15 do wind up lowering costs to consumers.

16 The degree to which that happens, depends on the
17 particular assumptions, but, under no set of assumptions
18 that I tested, did the vertical demand curve do better, and,
19 in very many of the cases, it did a lot worse, as we'll see
20 in just a minute, since that's about all I have left.

21 (Laughter.)

22 MR. HOBBS: Slide No. 4 lists a variety of
23 assumptions, and I was told there was an assumption that's
24 not on this list that I should follow up on this afternoon.

25 The first assumption is that generators forecast
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18895
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198

1 profits, based on experience, and that they don't like
2 risks. The more risk there is, the lower the forecast
3 profits are, and the less entry you'll get.

4 I also considered random shocks to the system,
5 whether changes in economic growth and load growth, how that
6 affects energy and ancillary service revenues.

7 Another assumption is, I'm simulating a market
8 clearing price-type system, rather than a pay-as-bid system.
9 I sit on the California Market Surveillance Committee, and
10 we've made quite clear, our preference for a market clearing
11 type mechanism for efficiency reasons and because, if you
12 have a pay-as-bid system, people, once they can guess where
13 the market clearing price is, that's where they'll bid. So
14 you're not going to get much difference, anyway.

15 I didn't think there was any purpose to looking
16 at a pay-as-bid system. I looked only at a system where
17 everybody gets the market clearing price for capacity, and,
18 in part, that's because I feel it's very important that all
19 generators get capacity payments, because all generators
20 have options for increasing their availability when you need
21 it, increasing the amount of capacity.

22 You don't want to be in a situation where, let's
23 say, you have a \$30 per kilowatt price for capacity for just
24 new generation. So you're paying a lot for new turbines,
25 and at the same time, there's some other generator that's

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18895
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199

1 retiring, that wouldn't retire if they got \$10. You want
2 everybody facing the same cost, so that everybody basically
3 equates the marginal cost of providing capacity.

4 Skipping very quickly then to the next slides, 5
5 gives an overview of the model. If you're interested,
6 there's an IEEE paper that's just been published, that
7 describes the guts of the model. I can answer questions
8 about that.

9 It's what's called a representative agent's
10 dynamic simulation model. It proceeds year-by-year.
11 Generators in a particular year look at prices and say, hey,
12 should I build something or not?

13 Slide 6 shows five curves I considered. One is
14 the vertical one, and four are various flavors of horizontal
15 curves shifted to the right, with different slopes.

16 The story that I'm going to tell today in Slide
17 No. 7, just basically contrasts the vertical curve, with
18 Curve No. 4. The important thing to bring away from here,
19 is that this is the sort of story you see.

20 The chart on the upper right shows what happens
21 to capacity revenues. With a vertical demand curve, you get
22 sort of a bipolar type behavior where prices are high or low
23 -- bang, bang -- whereas a sloped curve gives you more
24 stable revenues.

25 That translates into a willingness to invest at a
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18895
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200

1 lower return on equity, and the bottom curve on page 7 shows
2 -- this is a sample time series. The bold line shows the
3 reserve margins we got with the simulation of this slope
4 curve, versus the thin line, which shows that, with the
5 vertical curve, you're getting more investment, you're
6 getting a more reliable system.

7 In terms of consumer costs, Bullet No. 3, this is
8 just an example of numbers. The particular numbers depend
9 on the assumptions, but in almost every case, the vertical
10 demand curve gives you higher consumer costs.

11 What's the metric here? This is the sum of
12 capacity costs and scarcity revenues when you're short of
13 capacity, and so prices in the energy and ancillary services
14 markets, are going above marginal costs.

15 Because the vertical demand construct gives you
16 less capacity, on average, you're getting more shortages,
17 and you're getting a higher average ICAP price.

18 As a result, in these particular simulations, the
19 cost for consumers was roughly 30 percent higher -- excuse
20 me, 40 percent higher, at \$99 higher for the vertical curve,
21 than it was for the sloped curve in this particular
22 instance.

23 And that 50-percent or 40-percent difference,
24 depends on the assumptions that you make, and I wouldn't
25 ascribe any particular significance to 40 percent. It's
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18895
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201

1 just that you almost always see a positive difference.

2 That's the important result.

3 The next slide shows some detailed results, which
4 I would be glad to tell you about, returns on equity, costs
5 to consumers, and that sort of thing, but I'll just skip the
6 last substantive slide, which is No. 9.

7 The reason I like the sloped demand curve, is
8 that it logically reflects the reality of capacity value.
9 The value of capacity never goes to zero. It does decrease,
10 but it never goes to zero.

11 It's worth having more than the target value for
12 both mitigation and market power reasons, and because you
13 then have greater insurance against extreme contingencies of
14 weather or generator outage.

15 The result of the simulation was that, compared
16 to vertical demand, the slope of the curves lowered risk to
17 generators and the result was ultimately lower costs to
18 consumers, because of lower cost of capital. Thank you.

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18895
DAV

202

1 MS. COCHRANE: Thank you very much.

2 The next panelist is Reem Fahey with Edison
3 Mission Energy.

4 MR. FAHEY: Thank you. My name is Reem Fahey,
5 I'm the Regional Vice-President of Market Policy for Edison
6 Mission Energy. It's a pleasure to be here. Thank you for
7 inviting me.

8 Edison Mission Energy owns or controls
9 approximately 47,500 megawatts of coal-fired baseload units
10 in PJM. Such units provide energy capacity, ancillary
11 services, and support the overall reliability of the PJM
12 system. I would like to focus my remarks today on two
13 principle market design features that should be a component
14 of any contemplated PJM capacity market construct.

15 The first critical design feature should be the
16 inclusion of the demand curve. The principal benefit of
17 the demand curve is that it allows for a variable reserve
18 requirement that will provide a more robust incentive for
19 generation investment. The demand curve recognizes the
20 value of additional resources above the minimum reserve
21 requirements and provide benefits to both suppliers and to
22 load. The suppliers benefit from a more stable, predictable
23 revenue stream coming from the value of excess reserves. On
24 the other hand, load benefits from increased reliability and
25 reduced exposure to price spikes in both the capacity and

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18895
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203

1 energy markets. The design of the curve can also reduce
2 suppliers' potential to exercise market power. It reduces
3 the excess revenues that may result when the shortages are
4 created by withholding capacity. This is the same issue
5 that Joe Bowring talked about this morning.

6 If reserves fall below the thresholds of the
7 industry standard, which is loss of load probability of one
8 day in 10 years, the pricing factor will increase to
9 encourage generation investment to resolve the shortage.
10 When the threshold is reached, the pricing factor will drop
11 off slowly to recognize the value of higher generation
12 reserve levels. This leads to stable ICAP revenue, which
13 will reduce the risk and cost of financing investments of
14 new generation capacity and, thus, reduce the cost of
15 electricity to consumers in the long term.

16 A major market design flaw in the current PJM
17 capacity market is the use of the vertical demand curve.
18 The vertical demand curve sets the capacity obligation based
19 on a single value. The consequence is that prices can be
20 very low when a small supply excess exists and can suddenly
21 jump very high with a modest downward change in the supply
22 availability. The high volatile prices produced by the
23 current PJM capacity markets discourage the development of
24 new generation and, more importantly for EME, undermine the
25 reliability benefits of existing generation. This type of
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18895
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204

1 pricing behavior tends to convey contradictory investment
2 signals and leads to boom/bust cycles of generation
3 developments.

4 From a policy perspective, EME believes the
5 inclusion of the demand curve in the capacity market has
6 already been vetted and carefully considered by FERC for
7 both the New York ISO and the New England markets. FERC's
8 order regarding the New York ISO demand curve has been
9 affirmed on appeal, so FERC's authority to adopt such an
10 element of the capacity market has already been upheld.

11 A second principal design feature of a properly-
12 structured capacity market is the establishment of a forward
13 capacity obligation for all load-serving entities. A
14 forward capacity obligation sends a long-term price signal
15 that should provide the market with a greater opportunity to
16 determine the most cost-effective solution, whether it's
17 generation, transmission, or demand side, in order to
18 maintain the reliability of the system.

19 EME believes that a minimum of a four-year
20 forward commitment is necessary to allow new generation to
21 enter the market well in advance of when the capacity is
22 actually needed for system reliability. It also allows
23 existing generators to make informed decisions about
24 incremental upgrades to the units and also in regard to unit
25 retirements. Advanced capacity sales by generators may
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18895
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205

1 improve creditworthiness of merchant generation owners,
2 making it less costly and easier to finance planned
3 expansion and construction of new plants.

4 In addition, a four-year forward commitment
5 benefits load-serving entities as well, because it
6 facilitates a more robust and cost-effective transmission
7 planning process and, more importantly, it mitigates the
8 need to obtain reliability must-run contracts.

9 I would like to conclude by commending the
10 thoughtful and complete job the PJM staff has done in
11 developing and improving with unprecedented stakeholder
12 input to the current RPM proposal. Prior history makes it
13 abundantly clear, however, that the stakeholder process has
14 run its course. Further debate at that level will not
15 resolve any of the issues that remain. These issues require
16 the Commission's process to address the economic
17 considerations in light of the long-term reliability
18 concerns. Now is the time to file the RPM capacity market
19 proposal with FERC so it can be implemented by the summer of
20 2006.

21 Thank you again for the opportunity to speak, and
22 I look to further debate the issues during the Q&A session.
23 Thanks.

24 MS. COCHRANE: Thank you.

25 Our next panelist is Jonathan Wallach on behalf
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18895
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206

1 of the Maryland Peoples' Council.

2 MR. WALLACH: Thank you. My name is Jonathan
3 Wallach, Vice-President of Resource Insight and Economic
4 Consulting Firm based in Arlington, Massachusetts. I appear
5 today on behalf of the Maryland Office of Peoples' Counsel,
6 one of several supporters of the EITCC construct.

7 I want to first discuss the issue of the slope
8 demand curve and explain why it is that the EITCC construct
9 does not rely on an administratively determined curve to
10 clear its capacity auctions. Demand curve proponents
11 believe we have a problem with price volatility in our
12 current capacity market. They claim that prices -- as we've
13 just heard from Reem; don't take it personally.

14 (Laughter.)

15 MR. WALLACH: They claim that prices jump between
16 high and low extremes, clearing at the capacity deficiency
17 rate when the system's short and at near zero levels when
18 the system's long and that this extreme price volatility
19 exacerbates investor risk and stifles rational investment in
20 new capacity. Demand curves are seen as the solution,
21 stabilizing clearing prices and reducing the financial risk
22 to new entry.

23 The problem with this argument is that it doesn't
24 jibe with the experience in PJM. Prices in the multi-
25 monthly auctions in the last three years have averaged

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18895
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207

1 between \$20 and \$40 a megawatt-day, not zero even though the
2 system has been long during this period.

3 Moreover, neither capacity price volatility nor
4 excess conditions appear to have been a barrier to
5 investment. Over 15,000 megawatts of new capacity have been
6 added to the system in the last five years; an additional
7 15,000 megawatts for new projects are queued up for
8 interconnection over the next five years.

9 One reason for investors continued confidence is
10 the fact that there's a vibrant bilateral market in PJM that
11 allows parties to efficiently allocate price and other
12 risks. In fact, over the last few years, more than 95
13 percent of PJM's capacity obligation has been met with
14 bilateral transactions.

15 There is no question that reducing investor risk
16 is a laudable goal, since less risk means lower financing
17 costs and perhaps lower capacity costs to consumers. The
18 RPM demand curves, however, are not the way to get there
19 since they lead to short- and long-term inefficiencies. In
20 the short-term, while the system is long, demand curve will
21 procure excess supply at prices that exceed the marginal
22 value of that excess capacity. In other words, this excess
23 capacity will be paid more than its worth to stay on the
24 system when it should either be sold into higher-value
25 markets outside PJM or shut down. The increased costs to
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18895
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208

1 consumers from these short-term inefficiencies could easily
2 exceed a billion dollars per year.

3 Over the long term, the RPM demand curves
4 apparently expose investors to excessive price risk. The
5 modeling done by Ben at Johns Hopkins we've just heard about
6 indicates that investors under RPM will require a 20 percent
7 return on equity or 800 basis points more than the ROE that
8 PJM believes is adequate today to induce investment in new
9 peaking capacity.

10 The bottom line is that demand curves are the
11 wrong solution to a non-existent problem. Implementation of
12 demand curve under RPM will likely lead to inefficient
13 outcomes and substantial economic harm to consumers. In
14 contrast, the EITCC construct efficiently minimizes and
15 allocates risk and promotes general resource adequacy by
16 facilitating voluntary long-term bilateral transactions.

17 As this Commission has heard from the investment
18 community, including this morning from Brian Chin, such
19 contracts mitigate the risk and reduce the cost of
20 investment in new generation. Frankly, if new intervention
21 is deemed necessary to maintain resource adequacy, the
22 solution is not reliance on inefficient demand curve but a
23 construct whereby PJM directly procures new capacity on
24 behalf of load. This is similar to the EITCC mechanism for
25 addressing deliverability issues in small local areas.

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18895
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209

1 Switching gears, let me just touch briefly on the
2 RPM proposal to use a centralized forward procurement
3 process and the impact of that proposal on default service
4 customers in Maryland. Under the RPM construct, PJM will
5 procure capacity on behalf of all load in PJM to meet system
6 capacity requirements four years in the future. This
7 centralized procurement not only establishes a four-year
8 forward price for capacity, but also effectively creates a
9 four-year forward obligation on load-serving entities to
10 purchase capacity at the four-year forward price.

11 This four-year forward obligation is incompatible
12 with the provision of retail standard offer service in the
13 State of Maryland. Maryland utilities that provide standard
14 offer service would not be able to hedge price risks
15 associated with this forward obligation, since they are
16 effectively precluded by statute and regulation from
17 procuring capacity more than three years in advance of the
18 delivery year. So instead, SOS customers will be fully and
19 inappropriately exposed to capacity price risks as a flow-
20 through to SOS prices.

21 That completes my comments. I should mention
22 that I have submitted a prepared statement. There should be
23 some copies in the back and I will provide an electronic
24 version after this conference.

25 MS. COCHRANE: Thank you very much.

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18895
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210

1 Our next panelist is John Orr with Reliant
2 Energy.

3 MR. ORR: Good afternoon. Thanks for letting me
4 come speak with you today about capacity markets, I guess,
5 in general focused on the RPM and competing proposals that
6 we've seen out of, I guess I'll call them, the ODEC and
7 friends as well as the PPL proposal here.

8 I'd like to start off a little bit about Reliant.
9 Similar to what I think you heard Mr. Sorenson say on the
10 last panel about his company, Reliant is somewhat unique and
11 I want to be sure you have this proper perspective as I
12 speak to you.

13 And that is, while I think we're viewed as a
14 large generator in PJM -- which we are -- we are also a
15 significant retail player in PJM and the New Jersey markets,
16 as well as in Maryland. Nation-wide, I also serve more than
17 a million customers in the State of Texas without any
18 generation capacity to my name down there.

19 As a result, I'm concerned not with generators
20 getting paid for investment -- not that that's not important
21 -- or having a site in this market. What I'm looking
22 forward to is the balanced solution that achieves the goal
23 that resource adequacy is out to fulfill.

24 That transitions me into what I want to really
25 make sure we're all clear about here. What we're talking

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18895
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211

1 about when we talk about resource adequacy is a long-term
2 planning reserve. That means having iron on the ground in
3 the future in the form of generation. Not the delivery
4 capability that transmission wires gives you, but in the
5 form of generation that will keep people's lights on in the
6 future. And in the future is important, I think here.

7 In light of those concepts, I'm going to leave
8 you really with five principles that I think any of these
9 plans that are thrown in front of you you should apply as a
10 test for these. I think you'll see how they fit together.

11 First, you've heard this from some other speakers
12 this morning and this afternoon: is the design sufficiently
13 forward-looking to get the iron on the ground in the future,
14 yes or no. The reason this is important is because there's
15 long lead times for generation construction and if you do
16 not allow new entrants to compete, you will have market
17 power issues in certain locales.

18 Second, the second test I would apply does the
19 proposal eliminate barriers to entry? Does it let
20 generation be considered, transmission be considered, demand
21 response be considered? The reason this is important is
22 because it's the same thing. It's related to that last
23 concept of mitigating market power. You want enough people
24 in enough different alternatives to be there and be
25 available to you so that you don't have to impose mitigation
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18895
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212

1 and price caps and you can move more towards market-based
2 solutions rather than administrative ones.

3 The third element that I would say you should
4 apply as a test is is the design enforceable in such a way
5 that there are no free riders? What that means is that no
6 LSE or person serving load in this region or wherever the
7 construct applies is able to essentially count on their
8 neighbor to go procure something so that their lights stay
9 on in the future.

10 What I would tell you here is that until you have
11 targeted load shedding capability in this realm that we live
12 with RTOs in control of running the markets. There's
13 probably no better person than the RTO itself to be in this
14 role of we'll call it facilitator of procurement, something
15 Tom kind of touched on here and I think earlier commenters
16 for PJM touched on. They have to perform this role to make
17 sure there are no free riders. Once we get the targeted
18 load shedding ability, then we can let LSEs gamble on
19 whether they have enough in the future or not, because we'll
20 turn them off if they haven't met their requirements.

21 The fourth test I would apply is does the model
22 accommodate retail competition? Now I think we've just
23 heard Mr. Wallach make some comments around SOS. But what
24 I'm talking about here is does it allow for retail switching
25 in the states, because many of the states in PJM have this.

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18895
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213

1 Does it allow people to switch?

2 One of the key features of RPM, for example, that
3 highlights this is that load pays in the prompt year or the
4 delivery year based according to how much load they serve.
5 They're not being billed today for stuff they're gonna serve
6 four years from now. This gives them a price signal so they
7 can go do deals into the future and what they can do is
8 essentially hedge themselves around that using this market.

9 And here's another important point related to
10 this: no matter how we do this and who draws an IRM or the
11 like, we're gonna have forecast errors. So when anybody
12 comes to you and says well I can't hedge this because I
13 don't really know what I'm gonna have, we've got that
14 problem today on a grand scale. Every utility faces this
15 every day. PJM faces it every day when they decide how much
16 to commit in their unit commitment process day-ahead. So
17 don't be -- what I would implore you is don't be deterred by
18 that argument. What you need to have is make sure the
19 program in front of you accommodates retail access.

20 The last thing -- and this is really important,
21 too, and it kind of goes back to that first theme I said,
22 which is this is about having iron on the ground for the
23 future -- is that whatever is offered into this needs to be
24 real, it needs to be asset backed and deliverable.

25 There's a lot of talk about LD contracts and do

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18895
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214

1 they count and the like. What I would say to you is
2 somewhere behind the LD contract there'd better be a
3 generator, because all the financial penalties in the world
4 will not keep the lights on for somebody when you have a
5 problem or when you're run short.

6 When I apply these tests -- and I'm gonna wrap up
7 here -- when I apply these tests to the proposals in front
8 of us it's very clear to me, especially in light of the fact
9 that the forward-looking element is the linchpin of what a
10 good proposal has, I look at this and say RPM at least
11 attempts to address all of these issues. It makes a pretty
12 good attempt at it at that. I would hope that PJM does file
13 this with FERC and we move forward with refining that design
14 here in this forum.

15 The other two proposals, I believe, do not pass
16 some of these basic tests. They're fraught with
17 administrative remedies, potential for the exercise of
18 market power, they don't send necessarily a forward-looking
19 price signal. I think these are dangerous things contained
20 within these other proposals. What I'm saying is this is
21 the test we need to apply.

22 I appreciate your letting me talk to you today.
23 Thank you.

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1 MS. COCHRANE: Thank you, John. The next
2 panelist is Steve Wemple with ConEdison Energy.

3 MR. WEMPLE: Good afternoon, Commissioners and
4 Staff. My name is Steve Wemple and I'm the Director of
5 Retail and Regulatory Affairs for ConEdison Energy, which is
6 a subsidiary of ConEdison, Inc.

7 ConEd Energy and its affiliate, Solutions in
8 Development, are active in the three ISO markets in the
9 North East: New York, New England, and PJM.

10 Like Reliant, we're a diversified company. We
11 own about 1500 megawatts of merchant generation. We also
12 serve about 2,000 megawatts of retail load. We also provide
13 load-following services and other hedging products, as
14 financial derivatives, and we provide demand response and
15 traditional energy services.

16 Last year I think I sat in the same seat. I
17 testified before this Commission in the proceeding on
18 compensating local generators.

19 While some of the issue have been raised that are
20 the same, I think it's worth noting at least one theme that
21 came up last year. There's a real need to come up with
22 market solutions to compensate the resources that are needed
23 for reliability.

24 That's a theme we had a year ago in February. I
25 think it's still the same theme we're struggling with today.

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Simply put, market solutions allow all resources, including generators, people willing to invest in transmission and demand response, to see a price signal for the reliability service they are providing, whereas non-market solutions result in discriminatory compensation and create un-hedgeable costs for consumers, and typically fail to attract a reasonable level of demand response that you would expect, if you're valuing the reliability service at the level of that out-of-market payment.

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My comments today focus on some of the shortcomings of the current PJM capacity market, and outline the importance of integrating demand responses as a full participant in the capacity markets.

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As you heard earlier today when Commission Brownell teed things off, we currently have split the compensation between energy and capacity. The reality is that that's where we are.

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Maybe in the future, we can get back into an energy-only market, but if we want to get demand response as a full participant in our markets, we have to make sure that it sees both components of these price signals in a full fashion, and is able to respond to both.

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Otherwise, you'll be depriving demand response of some of the revenue stream that you really need, and that it

18895
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217

1 should be seeing in that ideal end state of an energy-only
2 market.

3 As you're aware, PJM's current capacity market
4 values all network resources equally throughout the PJM
5 footprint, and relies on the transmission system to ensure
6 deliverability.

7 While this approach worked reasonably when PJM
8 was a little bit smaller, it's showing some problems in the
9 expanded footprint. Simply put, we can't support a system
10 where local loads rely on remote generation that's located
11 as far as 800 miles away.

12 The physics of the system does not support that.
13 You need local equipment to maintain reliability.

14 At the same time, the general surplus throughout
15 the PJM region has been pushing capacity prices to historic
16 lows, albeit, not zero in the forward markets, but 20 to 40
17 bucks a megawatt-day is pretty low, and has resulted,
18 according to the PJM State of the Market Report, in under-
19 compensating new entrants, leaving them with a third to a
20 half of what they need over a five- to six-year period, to
21 cover their cost of investment.

22 If recent investors like ConEdison Energy, have
23 been getting only half their money for the last five years,
24 one would expect they're not going to reinvest until they
25 see a situation that gives them more than their average

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18895
DAV

218

1 return, so they have a chance of breaking even over the long
2 term.

3 There is no expectation, given the current market
4 structure, that we're going to see that in the local areas
5 under the current capacity construct.

6 PJM has recognized that some units that have said
7 they are not covering their costs, such as the PSEG units we
8 heard about earlier, are needed for reliability and have
9 been offered the opportunity to seek RMR compensation.

10 While it's important to maintain reliability,
11 that compensation means that demand response in the same
12 area and other generators similarly situated, are not
13 getting the right price signal.

14 In order to achieve an efficient market outcome,
15 the PJM capacity construct must be restructured to allow
16 demand-response and traditional generators to see that right
17 price signal.

18 If units needed to maintain reliability, are
19 given a payment of \$50 a kilowatt-year to stay in service
20 for reliability, demand response that's capable of
21 curtailing at levels at or below that same price, should
22 also be able to be compensated.

23 Putting everybody on a level playing field,
24 assumes customers can hedge their costs, either by entering
25 into bilateral contracts with local suppliers, or by
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18895
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219

1 investing in their own demand response measures.

2 Moving to the issue of demand response, under the
3 RPM proposal, demand-response participants can either sell
4 their capability to curtail load as capacity into the PJM
5 markets, or elect to participate right before the delivery
6 year by enrolling -- and I'm going to read the acronym
7 because every time we come up with a new acronym, it's
8 confusing -- interruptible load for reliability program --
9 there months before the program year.

10 Because the capacity value that the ILR program
11 will convey, is effectively determined by the auction that
12 happened four years forward under the RPM proposal, demand-
13 response participants can use the results of that four-year
14 forward auction to plan their demand-response strategies and
15 determine what measures are economic to invest in.

16 For example, under the RPM program, when a
17 customer elects to participate in a given year's ILR
18 program, they will effectively know the value, not just for
19 the upcoming planning year, but for the following three
20 years. All of those auctions were predetermined.

21 This forward valuation can help customers and
22 demand-response providers determine the installations and/or
23 equipment upgrades that are cost-effective and that should
24 be pursued.

25 For example, existing projects requiring less
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18895
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220

1 than ten months of lead time, will basically be able to bank
2 on a known revenue stream for the first four years of their
3 operation.

4 RPM timeline also allows customers with existing
5 and planned demand response, multiple ways to optimize their
6 capacity value, in addition to selling into the four-year
7 forward auction.

8 If they are not cleared of that auction, the ILR
9 gives them a floor price, knowing that they won't do any
10 worse than the price in that forward auction, so they can
11 look to improve upon that by offering their capability into
12 subsequent incremental auctions.

13 Although ILR participants do not directly
14 interact with the base residual auction, the RPM design
15 ensures that demand response will impact the clearing price
16 in the base residual auction and reduce capacity prices for
17 all consumers.

18 This is because PJM's plan assumes a quantity of
19 ILR will participate in the future planning year and clears
20 the initial base residual auction as if that amount of ILR
21 had actually offered to sell and was cleared in the auction.

22 For example, if 5,000 megawatts of demand
23 response is assumed to participate in a future year's ILR,
24 PJM will clear the auction as if that capacity was there and
25 had been bid in, and did clear.

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18895
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221

1 So, we've moved down the demand curve and you
2 will have the societal benefits of that demand response
3 participation. In contrast, the EITCC proposal, in my
4 opinion, is not likely to attract as much demand response,
5 especially in zones and local load pockets, and, therefore,
6 is like to result in un-hedgeable costs, because it relies
7 on RMR payments and transmission solutions to solve
8 reliability problems that are more granular than the two
9 relatively broad locational capacity markets that are
10 envisioned for the Eastern MAC and Southwestern MAC regions.

11 This coarse approach to local capacity markets,
12 ensure that if the Eastern MAC region fails to generate a
13 price high enough to attract the resources needed to support
14 the reliability in, for example, the PSEG Zone, then an out-
15 of-market payment will be made to specific PSEG suppliers to
16 ensure reliability until a transmission solution is built.
17 That sounds like where we are today.

18 That, in turn, will impose un-hedgeable costs on
19 consumers, and fail to value the demand-response measures
20 that could be cost-effective, compared to that RMR payment
21 or even compared to the transmission solution that will be
22 built to solve the PSEG problem in that example.

23 In conclusion, I'd like to reiterate that RMR
24 payments are a non-market solution, by definition. They
25 prevent other resources, including demand-response measures,
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18895
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222

1 from realizing the full value of the reliability service
2 they can provide.

3 Both the existing PJM capacity market and the
4 proposed EITCC construct, rely on RMR payments to maintain
5 local reliability. They will depress the price that demand-
6 response measures would otherwise receive under a true
7 market clearing solution, and, in my opinion, lead to less
8 demand-response participation than you would see in an
9 optimal solution.

10 Furthermore, the customer impact under a market
11 solution, is significantly different than under an RMR
12 solution. Under a market solution, as a retailer, I can
13 hedge my costs; under a non-market solution, those un-
14 hedgeable and unpredictable costs are a major risk for
15 consumers trying to plan a budget.

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1 To touch on two issues that were brought up
2 earlier today, one that was a little understated is the
3 operational and reliability metrics included in the RPM
4 proposal. Currently, PJM does not have any way of
5 compensating units providing 10 minute non-spinning or 30
6 minute reserves, even though it relies on those ancillary
7 services to maintain reliability. RPM seeks to solve that
8 absence of a market for that reliability service by
9 procuring it effectively on a forward basis. This is an
10 important element to complement PJM's markets and ensure the
11 right components that provide reliability are being given a
12 price for the service that they're providing.

13 The other issue that was brought up today is the
14 concept of looking at congestion. If the eastern MAC clears
15 at a high price uniformly throughout all the zones into New
16 Jersey, the supposition is that the reliability problem was
17 in eastern MAC. Just because you have congestion in certain
18 zones doesn't mean the reliability problems align with
19 those, say, in congestion zones. You could very well have a
20 lot of surplus capacity in eastern MAC, but outside of New
21 Jersey that just happens to be high cost because of the high
22 cost of natural gas and distillate oil and have an abundance
23 of supply from a reliability perspective. In the tight
24 pockets of New Jersey, for example, you might generate the
25 same price and be a lot tighter on supply and have a

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18895
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224

1 reliability problem that you would not see just from looking
2 at the gross aggregate LMPs.

3 That concludes my comments. Thank you very much.

4 MS. COCHRANE: Thank you, Steve.

5 The next panelist is Stephen Fernands with
6 Customized Energy Solutions.

7 MR. FERNANDS: Thank you. I want to express my
8 appreciation for being invited here. I feel like this sort
9 of brings me full circle. I started my first meeting
10 representing a client -- back then it was New Energy
11 Ventures. It was a PA, Pennsylvania Commission hearing on
12 capacity markets. I was fresh out, starting -- putting my
13 shingle out and starting Customized Energy Solutions.
14 Commissioner Brownell was there and we said boy, we need a
15 capacity market. At that point in PJM, everything was
16 bilateral. We had people saying at that point why do you
17 need a market, you know, we just all do this bilaterally,
18 everyone agrees here, you don't need any type of transparent
19 market. And we set up the daily market and the forward
20 markets that we have today. Those markets have evolved
21 greatly since then, but the foundation was laid back then.

22 So I appreciate the opportunity now to come and
23 talk about that. I've been involved in pretty much every
24 capacity iteration since then at PJM from some of the early
25 ones with many of the same people here.

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18895
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1 The fundamental question is why do we need
2 capacity markets. There are two reasons. The primary
3 reason is we don't trust that the energy markets will give
4 us the level of reliability we need. Why don't we believe
5 that?

6 Number one, a lack of demand side response. We
7 don't have customers that can respond to prices and produce
8 their consumption when prices are high. The second reason
9 is we don't have adequate transmission systems to deliver
10 all the electricity to customers; therefore, we say we need
11 locational markets.

12 It's because of those two reasons that we now
13 have probably one of the most convoluted central procurement
14 non-market based mechanisms ever proposed in the history of
15 PJM, and we're talking about it like oh, yeah, this sounds
16 like something, you know, we can talk about. It's
17 antithetical to a competitive market where you have the ISO
18 going out on behalf of load and procuring the entire
19 capacity responsibility. It will kill bilateral markets, as
20 mentioned by TPL, and I thoroughly agree with them.

21 So how do we get to the problem? One of the
22 things we address is the root. So you say okay the root's
23 not enough demand side response and not enough transmission.
24 Then, RPM, does that solve that root problem?

25 For those of you who are trying to follow on
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18895
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226

1 paper, mine's the little one with the lightbulb in the
2 corner.

3 There are four major reasons why RPM is anathema
4 to demand side response. I have been active in PJM's demand
5 side response program since it started. Our company chair,
6 Rick Mancini, chairs the price responsive load working group
7 in New York. We've been very active on demand side response
8 issues in each of the markets we've participated in.

9 RPM in particular does not work for demand side
10 response resources, at least not the ones I represent and
11 the ones that are currently participating in PJM's markets
12 that I work with. The first area is forward procurement.
13 Right now you're asking demand side response to commit a
14 month or two actually prior to June 1st that they will
15 reduce their peak consumption during the summer period. Now
16 you're asking them to forecast what their peak's going to be
17 three years from now and how much they're going to be able
18 to reduce that peak in the fourth year. I believe very few
19 customers, even the most organized, have great business
20 plans and know where they're going, are able to accurately
21 forecast those types of uncertainties in the market.

22 According to a study done by Neenan and
23 Associates in response to an earlier iteration of RAM, they
24 -- to quote them -- an objective of the RAM Group was to not
25 discriminate among resource types. The results of the

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18895
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227

1 demand resource providers surveyed clearly indicate that
2 many current demand resource providers would not be able to
3 participate in a CRAM with a three-year planning horizon.
4 So we're now looking at four. That study looked at six
5 months to three years and found the lowest response rates
6 and lowest participation rates in the three year and the
7 highest participation rates in the shorter term.

8 Next is the locational component. There's a lot
9 that's been made of well we have these locational problems,
10 we need to address them. And I completely agree with that.
11 We do have problems right now locationally, they do need to
12 be resolved. However, we're looking to try to trick
13 generators into siting there and then building the
14 transmission which is going to stop the premiums in those
15 areas and get a bunch of transmission owners that have
16 invested in the wrong place because the premiums that they
17 were expecting vanish as soon as the transmission upgrades
18 go in.

19 If we see a transitory problem that's going to be
20 resolved by transmission, it's much more honest to say let's
21 go, let's offer those customers RMR contracts while we're
22 building the transmission instead of trying to say we need a
23 market solution here for a very short-term transitional
24 problem. Same with demand side response. If you're trying
25 to trick demand side response, it won't work out. I hope it

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18895
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228

1 won't work with generation owners either.

2 The third thing is there's a disconnect with the
3 current expiration dates. We heard earlier today that there
4 will be some kind of demand side response program. I heard
5 Andy say it's going to be a continuation of the demand side
6 response program and made permanent. I wish that was
7 actually true and we can stop all these debates that we're
8 having in the demand side response working group. Currently
9 it's set to expire in 2007. There are a group of people,
10 myself included, trying to get it to expand. Right now -- I
11 counted 13 of the 21 people mentioned demand side respond
12 today. Over 50 times it's been referenced today.

13 Last year the incentive components for demand
14 side response were about \$200,000, so that works out to less
15 than \$4,000 per mention today of demand side response. It's
16 something that gets a lot of talk. That's not per megawatt,
17 that's like \$4,000 for the entire PJM the entire year
18 payment. It gets a lot of lip but it actually doesn't get a
19 lot of dollars and doesn't get people saying oh wow, you
20 know, demand side response, that's costing us billions of
21 dollars in capacity, we really need to fix that. We really
22 need to spend the money to make sure that we have the
23 infrastructure in place. We really need to spend the money.
24 So we have adequate demand side response instead of just
25 saying hey, yeah, it's important and then going on and
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18895
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229

1 phasing out the various demand side response programs.
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18895
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230

1 The fourth one is improper active load management
2 penalty. The Commission will hopefully be seeing something
3 filed by PJM later on this year.

4 Right now, if one of my clients is interested in
5 demand-side response, and being in ALM this summer, they
6 said, that's our risk. If you don't perform, per megawatt,
7 it's a \$6400 per megawatt penalty.

8 What's our revenue? Right now, it's about \$10
9 per megawatt-day. It's about \$3200.

10 So you're telling me, if I mess up once, I have
11 to pay two times the amount that I get paid for the whole
12 year. Yes, that's about it.

13 And how many times do I have to perform during
14 the Summer? Up to ten. Could you imagine a generator
15 operating in those types environments? It's just ludicrous.

16 So we're trying to come up with penalties that
17 are market-based. The penalty currently pushes demand-side
18 response out of the capacity market.

19 So, what does PJM need for a long-term solution?
20 Number one, it needs a goal-driven demand-side response
21 market, so you don't get somewhere just by saying, that's
22 nice; I'd love to go to Aruba, but if I don't book a plane,
23 if I don't plan for it, I'm not going to go there.

24 If we think we need so much demand-side response
25 to actually fix the market, let's plan for it. Let's say,
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18895
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231

1 okay, this is the amount we need to alleviate market power;
2 this is the amount we need to move to a more market-based
3 system, and head there, find out what are the incentives and
4 what are the things we need to do to get there.

5 The second one is a permanent seat for demand-
6 side response in the market. Right now, we've been going
7 with programs for so many years, there have been proposals
8 put on the table to do away with any type of incentive
9 payments and decrease the amount of revenues that are given
10 to demand-side response by some of the other panelists that
11 have been on here today, instead of saying we need to be
12 increasing demand-side response, not decreasing.

13 It needs to be permanent; it needs to reflect the
14 benefits of demand-side responsiveness.

15 The third thing I have here is, if loads paying
16 hundreds of millions of dollars in capacity payments for not
17 having proper demand-side response, what's the value of
18 demand-side response, if it is able to fix that problem, and
19 how do we compensate demand-side response adequately for
20 creating a more functioning wholesale market?

21 So, where will DSR get you, that the capacity
22 market won't, especially the RPM market won't? First, DSR
23 will result in a more efficient use of generation resources.

24 P.S., I'd just mention that we have two
25 generators that never ran. It's horrible that we lost those

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18895
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232

1 generators, and that they retired them.

2 Eventually, resources retire, and resources that
3 are unutilized, retire. If they're not using them, the idea
4 of having those resources around to provide ten hours a year
5 of service, demand-side response can do that. We don't need
6 to be paying generators to stand around and do nothing.

7 The next thing the demand-side response will do
8 that this capacity market will not do, is that there will be
9 rational pricing during periods of scarcity, with the value
10 of load-curtailing setting the price, instead of generation
11 market power. It's probably one of the most important
12 things that demand-side response can provide.

13 It can provide what is the value of energy during
14 times of scarcity. Right now, we don't know. Right now, we
15 have lots of artificial price caps and other things that
16 interfere with that.

17 We need to create ways demand-side response can
18 actively participate in the market and can set price. And
19 they do that in the day-ahead market right now, and, I
20 believe, if we continue to encourage that, we can even get
21 more participation.

22 The third way is, there will be less need for
23 price caps and mitigation, as demand-side response will
24 mitigate the market power of generation owners.

25 Locational capacity markets go 180 degrees in the
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18895
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233

1 other direction. It's going to increase market power of
2 generation owners, as you shrink the markets.

3 We already have a capacity market that has been
4 characterized as having market power, endemically. If you
5 look at the State of the Market Report, that gets better
6 with demand-side response; it gets worse as you Balkanize
7 the transmission system.

8 The fourth thing is that the demand-side response
9 will provide a market signal for more efficient generation,
10 including baseload units. Instead of sending a price signal
11 for increased peaking units right now, one of the wrong
12 signals locational capacity can send, is that you end up
13 perpetuating a market that ends up being more and more
14 Balkanized, instead of doing transmission solutions or
15 demand-side response across the market.

16 I also wanted to mention -- and some of these
17 have already been stated, so I won't reiterate all of them,
18 but -- some fallacies about the existing capacity construct.

19 One is, prices are either at the deficiency rate,
20 or zero. It's not true. Academically, I think there are
21 reasons maybe why it should be, but it is not.

22 There's an opportunity cost generators have of
23 participating in the day-ahead market. The opportunities,
24 they give up by not being able to sell firm, go back into
25 other markets.

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18895
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234

1 Prices vary between \$20 and \$100 per megawatt-day
2 in the monthly and forward markets. As recently as last
3 Summer, we were very long, not as long as we are now, but we
4 were long on capacity.

5 The monthly markets during the Summer were
6 regularly clearing about \$60 per megawatt-day throughout the
7 Summer.

8 Fallacy Two: Demand-side response can't
9 participate in PJM's current capacity market; you've heard
10 that a couple of times today. They absolutely can; we do on
11 behalf of our clients, and they're able to participate
12 effectively in the markets.

13 The third one is that the daily market serves no
14 value. Right now, less than two percent of the capacity is
15 purchased in the day-ahead capacity market. It does serve
16 as a clearinghouse for load-switching and also relieving
17 short and long positions.

18 I believe it offers new generation that sites
19 opportunities to sell and lowers opportunities to purchase
20 relatively small quantities, as the market has been
21 relatively small.

22 It also provides a more visible pricing note to
23 the market on a more real-time basis, so that people can
24 respond better.

25 Fallacy Four: Generators need one year of
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18895
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235

1 capacity revenues, four years out, to secure financing.
2 Hopefully that's been debunked by what you've heard already.

3 Fallacy Five: To determine what transmission
4 upgrades are needed, you need a four-year commitment ahead,
5 and you can't do it probabalistically, and we have to close
6 our eyes and say all the generators are going to stay there
7 because I haven't gotten a letter saying they're going to
8 not go away.

9 We can make forecasts before generation will
10 retire. That can be done, especially in large sections of
11 the PJM system.

12 So, in conclusion, the root cause of the capacity
13 market is insufficient demand-side response and transmission
14 development. It can be dealt with in a more efficient way
15 than the RPM.

16 The EITCC proposal does go a long way towards
17 improving the RPM model, by restricting the timeframe to one
18 year. Demand-side response can participate more readily,
19 and there are also auction mechanisms they've proposed, for
20 those locational problems, which would also be a place for
21 demand-side response to participate.

22 As well, the EITCC proposal deals very directly
23 with the need for transmission enhancements. However,
24 EITCC's proposal, even though we've helped and many of our
25 clients support it, I believe it's better than RPM, but

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18895
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236

1 still worse than what we actually have today.

2 In looking to improve our transmission planning
3 and creating a road map for increasing demand-side response,
4 and improving the underlying reasons why we need the
5 capacity market in the first place, is the way to go.

6 I want to thank you for the opportunity, again.
7 That will conclude my remarks. Thank you.

8 MS. COCHRANE: Thank you, Steve. Having the
9 dubious responsibility of being the last panelist of the
10 day, is Mark Scott from Old Dominion Electric Cooperative.
11 We are running behind now. I would just ask what
12 Commissioner Brownell said at the beginning, if what's on
13 your discussion has already been discussed, if you can just
14 say it, as someone said before, you know, thank you very
15 much.

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18895
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1 MR. SCOTT: Thank you very much for the
2 invitation to make some remarks. I'm Mark Scott. I'm here
3 on behalf of Old Dominion.

4 I'm an active supporter of the EITCC proposal. I
5 would like to leave you with three main themes here today,
6 that I will hit, and then touch on a few of the parts of my
7 actual remarks, my outlined remarks, that haven't been
8 covered by other speakers, and then I will try to wrap it
9 up.

10 The first thing is that there are not shades of
11 gray in terms of comparing the alternatives. EITCC is a
12 more market-oriented approach in terms of how individual
13 participants manage their obligations and their risks.

14 RPM is an administrative solution that, in my
15 opinion, puts PJM generally in an inappropriate role in
16 terms of the procurement function. When I speak later about
17 the one topic that I will expend some more detail on, on the
18 bilateral contracts, I'll try to make that much more clear.

19 I've heard throughout today, people complaining
20 about shorter horizons like one year, one month, two years,
21 and four years has become the Holy Grail as if there's
22 harmony if that occurs, and there's benefits of reducing the
23 volatility if we go further out.

24 The question I wanted to pose is, even if we have
25 a shorter horizon, I wanted to ask everybody throughout the

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18895
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238

1 day that made those statements, what keeps you from selling
2 that product forward two or three years, today, to a willing
3 buyer?

4 Unfortunately, it's going to have to be at a
5 mutually-agreeable price. That's where we get to crux of
6 the issue here.

7 We can talk about the theory of what sends the
8 proper signal and how we properly define the right
9 obligation. As you see, most of the folks here now are
10 admitting that there's some local element that's necessary.

11 That would include that, in the market, that
12 there would be a signal. If it's a unit that has concerns
13 about their retirement profile, they could lock in the
14 revenue stream, if they sold their capacity, common or
15 local, as we saw it going to, and they can improve certainty
16 of revenue.

17 But it goes past that. We're not talking about
18 the actual sending of a price signal; we're talking about
19 the level of the price signal.

20 When I get into discussions with my younger
21 children, it's differentiating between need and want, and I
22 think that is a core issue, which we're really wrestling
23 with here today, and why the stakeholder process has had a
24 hard time coming to an agreement on that particular issue.

25 The second main theme I would like to leave you
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239

1 with is, when I listened to some of the others earlier, I
2 felt like we were being done a favor by the load community.
3 People were damping volatility, they were reducing risks for
4 investors, and everybody's a winner, right?

5 That's not happening for free; there's a price
6 attached to it. The estimates range -- whether it's \$1
7 billion or \$5 billion a year, during the visible horizon
8 where we can see higher costs.

9 There are savings that are promised, based on
10 equilibrium model. Once we have this equilibrium, I'm not
11 as confident at this point, in the changing and dynamic
12 industry, of how predictive that equilibrium model is or
13 isn't.

14 Maybe it's right on, but what I can see, I know,
15 costs more, and if there's individual participants who wish
16 to manage the risks or are concerned about the volatility,
17 the individual participants can weigh off that risk, or
18 leave it to people who are better capable to step in and
19 manage it.

20 We don't have to have somebody to step in and do
21 that on behalf of every market participant for 100 percent
22 of obligation for four years forward, including all load
23 growth. Those are fundamental differences in approach.

24 The third thing -- and it's the important one --
25 is that the bilaterals are going to have a similar role

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240

1 under either of the alternatives, and that market
2 participants have comparable incentives to enter into.

3 I'm going to touch on just a couple of points on
4 my outline here, and that, I will cover much quicker. As
5 you've gathered, we're focusing on both transmission and
6 capacity. That seems to now be a more common theme in terms
7 of how the market looks.

8 Our market will operate on fungible capacity
9 credits. The common area remains the same as the construct
10 today, other than lengthening the obligation.

11 The non-local part of the local area still stays
12 common, and then there's a subset of the local obligation
13 where there's actual local sub-obligation. We are
14 acknowledging that there needs to be a element of flavor of
15 the current capacity construct, and that transmission needs
16 to be expanded with it.

17 The next section in here, which I'm going to
18 touch on very little, is the common misconceptions that I
19 think exist, that have already been touched on by a few
20 other people, but the reason I just wanted to reference them
21 and why they're here, is that some of these incorrect
22 conclusions, drive misguided actions on which construct and
23 which alternative, and which problem we think we're solving.

24 You've heard that over-reliance on short capacity
25 markets, impedes investment. Only one percent of the daily
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18895
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241

1 volume clears in the daily markets. Joe Bowring's Market
2 Monitor has incredible detail of long, short, what cleared
3 in the multi-month auction, what cleared in the monthly
4 auctions.

5 If you look at that, the bulk of the market is
6 operating on a longer horizon and a bilateral market outside
7 of this over-reliance on an extreme low or extreme high.

8 Price is a function of risk and time horizon,
9 even in periods of excess. The market's not digital. I'd
10 be happy to go into that in more detail, if time would
11 allow.

12 The other thing is, under RPM -- and I'm only
13 going to make one other comment or two comments here, is
14 that it might be a mistake to act like markets are bigger
15 than what they are in terms of local area, in terms of
16 granularity, but I think it's also an equal mistake -- and
17 maybe you get a different error -- but to act like you can
18 have a much smaller area and act like that's then a market.

19 If I'm down to a point of needing a plant on a
20 specific bus in a specific sub-area of the DDC, drawing a
21 boundary around it and putting in an administrative curve
22 and I force people to buy and serve against it, acting like
23 that's a market proxy process, at that time, I think you
24 have to step back and ask yourself, what a competitive
25 auction or procurement for capacity is in that area, and
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18895
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242

1 then handle how the pricing of that resource interacts with
2 the balance of the market, and do it in such a way that you
3 don't interfere and subvert the market process.

4 You have to step back and ask yourself that
5 question.

6 The other thing I will mention on here, is that
7 we've heard the benefits of a common time step. I will
8 credit RPM. They are trying to achieve a common time step
9 between transmission and generation, but I view that as a
10 disadvantage.

11 It's like saying that I and one of the other
12 participants on the panel, in total, have an average bill.
13 It's true, in total, but, in practice, not really right on.

14 Some of the transmission solutions are longer
15 lead time -- five, seven, ten years. By forcing a solution
16 on the four-year horizon, you have more longer-solution
17 items.

18 By contrast, combustion turbine projects can be
19 done in two years. Why should anybody commit on my behalf
20 to build a peaking facility and cost it four years out? I
21 don't have to commit to that; I can do that to myself on a
22 much shorter time horizon.

23 Why should the market force that to occur
24 arbitrarily at the four-year point?

25 I guess the final point or two that I'd like to
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18895
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243

1 make are on this next table. It's kind of what I've laid
2 out or compared between RPM and EITCC.

3 This really gets at the market versus the
4 administrative process. Under RPM, part of how that
5 administrative price curve is set, is based on kind of
6 really a net revenue or cost-of-service type determination
7 from an equilibrium model.

8 They do adjust it, and there is feedback. The
9 person buying it is PJM. The pricing, which is critically
10 important in the competitive market, is how price gets set,
11 based on this curve.

12 It's not willing sellers and willing buyers. You
13 are clearing the market, four years out, on all obligations,
14 looking at projected load for everyone.

15 Assuming that every market participant needs to
16 be fully hedged for four years out, that also is going to
17 impact the bilateral markets, and I think the way that I'd
18 like to respond to or address that is using Andy's earlier
19 energy analogy about how, well, people said we're going to
20 go to LMP and that would destroy the bilateral market, and,
21 look, that's not the case.

22 I would agree that that's not the case, but that
23 is a very different analogy, and that relationship is not
24 the same. LMP has a lot of localized stuff. The liquidity
25 comes through the hub, but when we went to LMP, we didn't
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18895
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244

1 buy everybody's, all their energy obligations, and lock in a
2 fixed price on their behalf for four years, which is what
3 we're doing under this item here.

4 Why would I ever enter into a bilateral
5 transaction, when you've defined my price for four years
6 out, of somebody serving load? And the way that I would
7 answer or respond to that, to anybody, is, if you're serving
8 load and you have an obligation to serve load, network
9 integrated transmission service is a tariff and a pass-
10 through.

11 How many people in this room actively feel they
12 have to manage and hedge the risk and enter into a bilateral
13 year five through ten in their nets? They don't. It's a
14 pass-through.

15 Everybody has the same price; it's common.
16 You're narrowing the size of the pie where participants can
17 really differentiate themselves.

18 I think the better model is, you focus on
19 defining the obligation that's at a common level, and a
20 local level, then allowing the market to clear.

21 And the final remark I will make on that is,
22 while we're allowing forward voluntary markets, in which
23 willing buyers and willing sellers set prices, there is a
24 final clearing auction that's going to clear the market two
25 months before.

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245

1 Much like today, I don't think there's any reason
2 to believe, like today, we had one percent in the daily
3 markets. I don't think there's any reason to believe that
4 the volume would look that much different, going into this
5 final clearing auction, than we have today, which is really
6 minimal.

7 So, those are my main remarks. There are other
8 items in here that I could go into with probably detail,
9 between market and non-market, but I think the difference in
10 that voluntary versus mandatory final clearing, is
11 consistent with how the energy market clears today.

12 We don't artificially force clearing the market
13 on an extended horizon. We're looking at organizing
14 informal commodity markets, perishable, non-perishable,
15 voluntary clearing markets, and the sort of voluntary
16 clearing of the market works.

17 You'd have to argue with too much precedent in
18 market activity to deny that. Thank you. Those are my
19 remarks.

20 MS. COCHRANE: Thank you very much. Dave?

21 MR. MEAD: I heard in your presentation, you made
22 the conclusion that the PJM RPM wouldn't work well, would be
23 a carve-out for IOUs. I was wondering if you could sort of
24 embellish on that? What do you see as the complication or
25 the disadvantages, if not just IOUs, but any LSE who could

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18895
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246

1 come to PJM, four years in advance, and say, I've met some
2 target level of capacity, here it is, I would like you to
3 take all my load out of the auction? Can you sort of
4 embellish on what those complications and disadvantages are
5 that you see?

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18895
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247

1 MR. WELCH: In a sense, RPM permits people to do
2 that in its internal structure but not quite the exactitude
3 that your question suggests. If I'm an LSE and I have an
4 IRP obligation and I'm sort of self-contained, to the extent
5 that when I get to the target year, my load is what -- I
6 have bid in enough capacity to cover the load that I
7 actually have, it's a wash. I am kind of out of it.

8 The difficulty of having an LSE just say four
9 years ahead, when I show up with whatever load I show up
10 with four years from now, ignore me, because I've kind of
11 dealt within my own little way. It's hard to know how you
12 can even talk about that person as being part of the market.
13 There's presumably going to be some difference. There
14 could, at least in theory, be some difference between what
15 they bring to the market on the capacity side in the target
16 year and what they bring to the market on the load side in
17 the target year.

18 The question is what do you do with that? Do you
19 allow them to meet some different obligation than the market
20 as a whole, which actually creates some inefficiencies for
21 the market as a whole, or do you sort of treat them as RPM
22 treats them and say okay you have to meet the target
23 obligation to the market as a whole and, to the extent you
24 miss, you miss and you pay the RPM price.

25 I guess, as I said, the details of exactly how
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18895
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248

1 that work through are ones that we have to work on but I
2 don't think the answer is to have people be able to say in
3 year one when you're looking at year four, you can just
4 ignore my existence beginning in that target year because
5 somehow it will all work out for me.

6 MR. BANDERA: Just to follow-up, like the
7 representative from AEP was sort of talking about that. I
8 don't think he was saying that's what he wanted. It sounded
9 like they do have a vertically-integrated structure and they
10 would be able to identify their resources or resources that
11 they would be bringing forward given that they don't have
12 the sort of retail competition type situation that really
13 poses a problem and in many ways is the reason that the
14 structures are necessary. It just sort of seems that if
15 they were able to make those showings under some guidelines
16 that it would be compatible.

17 MR. WELCH: I thought I heard him say something
18 slightly different actually. I heard him say that they
19 should not be subject to the overall capacity requirements
20 because they have one of their own. I think it's an
21 interesting question about whether the one that he described
22 at 15 percent compared to an 18 percent to which RPM might
23 clear is actually apples to apples. I think they're
24 probably not. I think the one they actually use is probably
25 a lot more like a team if you take into account for future
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18895
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249

1 uncertainties and things of that nature.

2 So I mean I did hear him say let us determine in
3 our little world what our standards are; as long as we meet
4 those, you can ignore us. I don't think that addresses the
5 problem that in fact if they're short the rest of the PJM
6 market is going to be asked -- they're going to be drawing
7 on capacity from the rest of the market. If they're long,
8 they're going to be selling it into the PJM market where
9 you would have a completely different set of rules for a
10 particular entity. Because they were structured in a
11 particular way, it's not obvious to me why you wouldn't just
12 accommodate them by saying okay, you're going to have a
13 certain amount of generation, fine, bid that in. If your
14 predictions are correct, it's going to wash.

15 MR. BANDERA: You have the load curtailment
16 opportunities. With a load structure like PJM, it would be
17 like the one -- like being on the same distribution system.
18 You can't cut off one without the other. But in the AEP
19 system it would be one that would be consistent with the
20 ability to sort of say you guys didn't come up with what you
21 wanted to, you can't lean on the additional resources that
22 everyone else outside of this region is procuring.

23 It does seem like it would be a situation --

24 MR. WELCH: In a sense, if you can take it
25 outside the context of just the vertically-integrated

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18895
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250

1 utility, which in a sense could be looked at as just another
2 load sitting somewhere, if you ever get to the point where
3 you can cut off particular loads, that has interesting
4 implications for what their obligations are. It's just not
5 obvious to me that you'd want to say up front until that
6 something that's both possible, politically likely to be
7 sustainable, or available to a broader set, you'd want to
8 leap to the conclusion that says okay because you happen to
9 be vertically-integrated, we're going to treat you
10 differently than the rest of the market. I guess it's not
11 obvious to me that somehow that's the conclusion you get to.

12 I do agree once you get to the point of being
13 able to shut off individual loads -- when I say "get to the
14 point," I just don't meant technologically, I mean
15 politically and a variety of other things. I think that
16 does have some interesting implications for what you should
17 be paying because in a sense you may be getting a different
18 service than somebody else. I don't think we're there.

19 MR. O'NEILL: Do we have a chicken-and-egg
20 problem here? Once you get to that position things change,
21 but we don't know how to get to that position because you
22 won't give people an opt out.

23 And the other question I have, are we saying that
24 AEP gets to determine its own reliability criteria?

25 MR. WELCH: That's what I heard, the suggestion

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18895
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251

1 from the AEP witness. I may have misheard it, but my sense
2 was that AEP would say I have a commitment my state
3 commission has imposed on me and as long as I meet that one
4 I should be subject -- to the extent I misunderstood or I
5 misunderstood it, but I think that's what I heard him
6 saying.

7 MR. O'NEILL: I don't think we allow people to
8 set their own reliability criteria.

9 MS. COCHRANE: Can I say that since he's not
10 here --

11 MR. O'NEILL: As a general rule, do we let people
12 set their own reliability criteria? The reliability
13 council, not the individual utility.

14 MS. COCHRANE: I think that we will have an
15 opportunity for people to file comments after this, so maybe
16 if we can --

17 MR. O'NEILL: It's a generic issue. It's not
18 just AEP.

19 MS. COCHRANE: It is a generic issue and maybe if
20 Tom can address it as more of a generic issue instead of on
21 what --

22 MR. WELCH: Okay. Again, if you're trying to
23 capture the benefits of the broad market, it seems to me
24 just intuitively you want to have the rules as generally
25 applicable as possible. In the question you say are we
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18895
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252

1 somehow preventing people from dealing with -- if they have
2 the ability to curtail load, are we cutting off that or are
3 we taking advantage of that? I don't think so. That's one
4 of the reasons the demand products are being created. There
5 are just a variety of ways of capturing the economic value
6 or whatever you're doing at those points. I'm not sure why
7 that follows.

8 MR. O'NEILL: It seems that one of the demand
9 products, if you want to put things in categories, that
10 people are asking for is the ability to simply opt out of
11 the capacity market. That, to me, is a demand product. It
12 requires you to be demand responsive.

13 MR. FAHEY: Tom, if I may, I believe that PJM did
14 hear this AEP concern. In essence, the way they've proposed
15 to deal with it is, if you believe them, procure four years
16 forward for 15 percent, then they show up to the auction,
17 then they show up with their generation to the auction and
18 they self-schedule.

19 To the extent that the demand curve may procure
20 more than 15 percent -- let's say it procures 16 percent or
21 17 percent, what PJM has done to accommodate them -- and I
22 believe that's a change that Andy has done -- in essence
23 they allow you to sort of do two things with an asset: you
24 can self-schedule it to the extent that you meet your
25 requirements but then anything above that you can actually
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18895
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253

1 sell it in the market so you can actually put a sell offer
2 for the remaining amount. So I believe that this does
3 address the AEP issue.

4 One other quick question on why you can just kind
5 of carve it out and say well this is good enough. AEP is in
6 a retail state. Who's going to serve some of the load
7 that's going to leave the AEP system? In essence, that's
8 what the RPM proposal does. To the extent they think they
9 don't have the load and the retail supplier says well I'm
10 not serving that load, PJM knows the load is out there and
11 we're going to make sure that load gets covered. As long as
12 they're in a retail state, that's something important that
13 needs to be considered.

14 MR. MEAD: One of the concerns I thought I heard
15 AEP mention was the variable resource requirement; going
16 into the four year auction, they don't know exactly what
17 their requirement is. If there could be some agreement in
18 advance that if I'm bringing them the requirement -- if it's
19 15 percent or PJM thinks it ought to be 18 percent or
20 whatever it is, if you could name that requirement and some
21 LSE says PJM, you forecasted my load to be X, here's 115
22 percent of X, here it is, take my whole load out of the
23 auction, I don't want to be subject to the variable
24 requirement -- which may turn out to be 12 percent or 124
25 percent depending on what happens at the auction. Is there
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18895
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254

1 something wrong with that sort of option?

2 MR. FAHEY: In essence, a generator within the
3 AEP system. I mean, if you look at the demand curve, the
4 only time the demand curve procures more capacity is if the
5 total cost of the capacity is lower. They're not procuring
6 capacity and increasing everybody's costs, because it's
7 sloped down. So the extent that they're procuring a little
8 bit more capacity, the resources that AEP has they can hedge
9 against, it could be 16 percent or 17 percent because they
10 could self-schedule their units to say if it's 16 percent
11 use this unit but to the extent that there is extra
12 megawatts, then sell it in the auction. And they're
13 completely hedged that way.

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18895
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255

1 MR. O'NEILL: I'm not sure whether you're making
2 the case for allowing them to opt out. If they're
3 completely hedged by what they put into the auction, you can
4 simply take them out.

5 MS. FAHEY: I'm not saying -- this doesn't
6 address their issue their issue 100 percent. Their issue
7 is, I only want to procure 15 percent.

8 At least the demand curve brings many other
9 benefits. To the extent that they can opt out or, in
10 essence, PJM has designed the auction to allow their
11 resources, to allow them to hedge against the 15 percent,
12 all that I'm trying to say is, PJM has tried to address
13 their concern.

14 MR. O'NEILL: I realize there's a small glitch,
15 probably in that opt-out provision, but it may be small in
16 comparison to the lift it gets, politically.

17 MR. SINGH: Dick, this is nothing new. Under the
18 demand-curve approach, you can never completely self-
19 provide. That's something people know in New York.

20 MR. O'NEILL: That's the glitch, but how big of a
21 glitch is it?

22 MR. FERNANDS: If I may, to be able to self-
23 supply, I think you need to fit into the auction or submit
24 into the auction, up to the maximum amount, wherever the
25 demand curve intersects to zero.

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18895
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256

1 If it's 135 or 132, the way you won't have to
2 pass any additional costs on to your customers, through
3 additional procurements, is by supply enough capacity to
4 meet your load to the extreme of the demand curve where it
5 intersects with zero.

6 That's the only way you can completely hedge and
7 make sure there are no additional costs.

8 MR. O'NEILL: Is the system more reliable, if you
9 go out that far?

10 MR. FERNANDS: I don't believe so.

11 MR. O'NEILL: So reliability really is a cliff
12 that you fall off of at 18 percent.

13 MR. FERNANDS: I believe there might be
14 efficiencies in terms of reliability.

15 MR. O'NEILL: If you look at the way Steve
16 Herling develops those numbers, they come out of all kinds
17 of scenarios where there's all kinds of assumptions.

18 I don't know how you can believe that there's
19 some magic number where you fall off a cliff.

20 MR. WALLACH: Can I respond to that, Dick? There
21 are decreasing returns as you go further and further out.
22 You may not be falling off a cliff; there may be some tiny
23 increment of reliability improvement, but the question
24 always becomes one of what's the value of that increment?

25 MR. O'NEILL: I agree with you completely, and
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18895
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257

1 you believe it's a cliff that you fall off of. Let's say 15
2 percent gives you perfect reliability, and 15.5 percent
3 basically gives you too much?

4 MR. WALLACH: That has been the basis for
5 establishing --

6 MR. O'NEILL: And that model has so many
7 assumptions in it, that you could drive a truck through it.

8 MR. WEMPLE: Dick, in addition to the point you
9 raised, which is a good one, the amount of capacity to
10 maintain one in ten, is not a precise science, calculated
11 down to a tenth of a megawatt. It is a range of estimates,
12 depending on what you're driving in your forecast
13 assumptions.

14 But there are two practical considerations: If
15 one were to, hypothetically, consider a carve-out, one is
16 that the surplus capacity in the rest of the region that is
17 paying for it, actually not just provides the extra
18 reliability benefit, but also provides an energy benefit,
19 because you have a surplus bidding into it.

20 So, there are some equity issues about having
21 somebody be in one part of the PJM market, getting the
22 benefits from the energy side and not the other.

23 There's a separate equity issue of a vertically-
24 integrated entity saying, okay, even if it's 15 plus the
25 premium, 16 or 17, now I've got some extra capacity, that,
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18895
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258

1 guess what, is paid for in rate base. For that to the sell
2 into this competitive market, you could have all sorts of
3 strange mixing and matching, if that vertically-integrated
4 entity, with most of their assets, with all of their assets
5 in rate base, covering some of their requirements, then had
6 one foot in a competitive market.

7 MR. O'NEILL: I agree that it isn't a perfect
8 fit, but, you know, if it helps the process, I mean, let's
9 figure out how imperfect it is, and let's not make the
10 perfect the enemy of the good.

11 All of these things, to use Mark's term, all of
12 these numbers are administratively determined. They're not
13 generated by any market.

14 You're just choosing among the administratively-
15 determined numbers or demand curves or whatever. I realize
16 that it raises a lot of political hackles.

17 We say, oh, this is administrative. Everything
18 here is administratively determined. It's just which one
19 you want to choose.

20 MS. FAHEY: If I may, you posed the question to
21 some of the panelists about, well, what's the right level of
22 reliability? To me, I think the best example and real-life
23 proof of the demand curve, is what we have right now --
24 excess capacity, capacity prices are very low, and energy
25 prices are very low, and the only reason why these two
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18895
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259

1 phenomena exist, is because we have excess capacity.

2 And that's really what the demand curve tries to
3 do. It ultimately says, everyone benefits from a little bit
4 of excess, above and beyond targeted reserve margins.

5 MR. SINGH: I have a quick question for Tom, just
6 to clarify something that was said about PJM not being POLR.
7 I think that was a good point.

8 But if I'm a generator and I then win in this
9 auction that PJM facilitates, who is that contract with?
10 Who is my counterparty?

11 Isn't it PJM?

12 MR. WELCH: I mean, there is an obligation that
13 the generator undertakes, that if they do not fulfill it,
14 they are penalized through the PJM operation. Whether that,
15 technically, makes PJM a counterparty, I'm not sure, in the
16 legal sense, but to participate in the market, if you get to
17 the target year and you don't deliver, then you pay the
18 deficiency charge.

19 MR. SINGH: And if I deliver, who pays me the
20 money?

21 MR. WELCH: It's paid through the market.

22 MR. SINGH: My understanding is correct, then.

23 My question is for Ben. I think it's an
24 interesting study on volatility and its effects on cost of
25 capital. Did you see anything out there that relates
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18895
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260

1 volatility to levels of long-term contracting?

2 MR. HOBBS: Long-term contracting for capacity?

3 MR. SINGH: No, the argument that lower
4 volatility will give you lower cost of capital. I'd
5 actually like to take it further and say that the cost-of-
6 service ratemaking might even slow volatility, but I don't
7 want to go there.

8 (Laughter.)

9 MR. SINGH: Since your a professor, I think I'm
10 asking a more conceptual question. In the Australian
11 market, the volatility is fairly high there.

12 There's a lot of long-term contracting, and we
13 heard from Brian that long-term contracting is important for
14 investment, and cost of capital is another factor.

15 But it seems like you could really have opposite
16 arguments in both.

17 MR. HOBBS: So what's your question, Harry? I'm
18 sorry.

19 (Laughter.)

20 MR. SINGH: My question is, does higher
21 volatility give you more long-term contracts?

22 MR. HOBBS: It should.

23 MR. TIGER: If I could follow up with John
24 Wallach with a couple of questions, first, you mentioned the
25 15 gigawatts that are in the queue right now, so

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18895
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261

1 everything's working in PJM.

2 We talked a little bit about finance. Is it
3 financed? Is it in construction? Where does it stand?
4 Where is it being built?

5 And is that consistent with some of the goals
6 that are trying to be fulfilled in terms of the locational
7 nature of RPM? And then I have second followup that I'd
8 like to follow up with after he answers.

9 MR. WELCH: I wouldn't say everything is working
10 in PJM.

11 MR. TIGER: But, specifically related to the 15
12 gigawatts that's out there, where is it being built? Is it
13 actually close to being built?

14 MR. WELCH: I think what's in the queue,
15 depending which queue it's in, each of those products are at
16 different levels of development, and I don't have in front
17 of me, what percentage or at what particular stage, whether
18 they have an SSA or an ISA or whatever the other acronyms
19 are, in the various study agreements.

20 I do know that, for example, according to PJM, at
21 least the last time they provided this information, there
22 was not a lot of new capacity going into New Jersey and I
23 can imagine there are a number of reasons for that.

24 That certainly raised some concerns, that
25 locational aspect of it.

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18895
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262

1 MR. TIGER: My second question is related. You
2 mentioned that there were inconsistencies with RPM's
3 structure, especially the four-year-out nature and the SOS
4 in Maryland. Maybe you could elucidate a little bit
5 further.

6 You mentioned that the LSEs might be statutorily
7 prohibited from doing it. You could maybe further elucidate
8 that, as to why it wouldn't work.

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1 MR. WALLACH: We have settlement agreements in
2 effect in Maryland which limit contracts to terms of three
3 years or less. Basically, for someone, for a supplier on
4 behalf of load to hedge in the fourth year, they would have
5 to speculate, go out and procure capacity in some form or
6 fashion for that fourth year not knowing what their load
7 obligation would actually be, and that's pretty speculative.
8 And I don't know that there's going to be much of that going
9 on.

10 MR. BANDERA: It would end up being just a pass
11 through, so there wouldn't be any competition on that
12 aspect.

13 MR. WALLACH: My point exactly. It will be a
14 pass through. That means that load will be fully exposed to
15 the price risk associated with that pass through.

16 MR. TIGER: How would that be different to how it
17 is today without having the forward year. Presumably
18 they're still exposed to that fourth year. It's just not
19 being determined today.

20 MR. WALLACH: Suppliers who take on that risk and
21 pay the premium, there is a benefit to avoiding that
22 uncertainty and locking in at a higher price than you might
23 expect that price to be in the future.

24 MR. MEAD: I had a follow-up question for Ben
25 Hobbs. If I heard you correctly with regard to your study,

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18895
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264

1 you concluded that with a sloped demand curve compared to a
2 vertical demand curve, you've got both more supply and lower
3 customer costs and lower payments to generators over time.

4 MR. HOBBS: Conditioned on the exact location of
5 the curve, but generally in the ranges we were looking at,
6 yes.

7 MR. MEAD: If I understood you, this is a
8 simulation and the general reason for this result is that
9 suppliers like lower risk and with the sloped demand curve
10 they have lower price volatility over time that, in essence,
11 lowered the supply curve. Is that fair to say?

12 MR. HOBBS: Yes, not the way I've drawn it here,
13 but that's precisely what happens.

14 MR. MEAD: Can you discuss a little bit the
15 nature of the assumptions you made about either the nature
16 of the risk aversion or the nature of the shift in the
17 supply curve that got these results? Because I presume that
18 with different assumptions, you might have gotten different
19 results.

20 MR. HOBBS: With different assumptions, what you
21 get is different degrees of response. But you still get the
22 same basic response. The way the simulation is structured
23 is that you've got a generator, an agent sitting there who
24 has a history of energy and ancillary service prices and
25 capacity prices and has capacity prices for the next three
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18895
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265

1 years and some forecast of energy and ancillary service
2 prices; and they may be highly volatile, they may not be.
3 That gets translated through a utility function that if
4 curve represents the degree of risk aversion, if linear
5 means that all you care about is your expected profit out of
6 this, you get a risk adjusted forecast profit. The greater
7 the volatility in the history of prices, the lower that risk
8 adjusted profit would be. And, of course, the lower
9 generally prices would be, the lower that would be.

10 So it's true a simple mechanism of a utility
11 function that we adjust the actual time series of profits
12 into a single number, that then gets plug into a function
13 that says this is how much capacity I'm willing to construct
14 given my risk-adjusted forecast profit.

15 So the key -- there are three key sets of
16 assumptions: what series of time do you look at profits to
17 get your forecast profit, what your utility function is -- I
18 used a standard MBA-type constant risk aversion utility
19 function -- and finally, that function that translates the
20 risk-adjusted forecast profit into how much capacity people
21 are willing to add. Those things are all unknowable, at
22 least in a market which is incomplete, where you don't have
23 all the hedges and all the contracts you want against risk.
24 So the key thing in this simulation is to look at a wide
25 range of possible values with a degree of risk aversion for
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18895
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266

1 the degree of investment response and response to profits
2 and, finally, the ranges of years you're looking over this
3 variation.

4 Do I ever see the vertical demand curve doing
5 better than the sloped one? No. Sometimes they come very
6 close, but very often they're very far. So that describes
7 the mechanism of how the simulation works.

8 MR. MEAD: Is it fair to say you did some
9 sensitivity analyses and for even small amounts of risk
10 aversion you still get this result that any sloped demand
11 curve gets you both greater supply and lower customer
12 payments than a vertical demand curve?

13 MR. HOBBS: Right. But, of course, the degree
14 will be a lot less. If the agents are perfectly risk
15 neutral and there's no weather-driven uncertainty in loads
16 and so forth, you get exactly the same answer depending on
17 how you draw the curve from both the vertical and the sloped
18 one if you draw them through the right point. Risk won't
19 then matter. So it's all a matter of degree. The greater
20 the amount of risk aversion, the greater the amount of
21 volatility and the more the divergence will be. And I don't
22 know what the right number is, but the order of the two,
23 which one does better than the other, is always the same.

24 MR. WALLACH: I'd like to respond to that for a
25 second and say, with all due respect, Ben, to the work

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18895
DAV

267

1 you've done and to PJM -- I think they were the first RTO to
2 undertake the type of modeling that we should be doing to
3 look at what the impacts of demand curves are in the long
4 term, the fact is that I don't think you can really make a
5 meaningful comparison between the two cases that Ben was
6 just talking about, a vertical demand curve case and a
7 sloped demand curve case. And there's a couple of reasons
8 for that.

9 First of all, there hasn't been any benchmarking
10 of the model in particular looking at what the model would
11 say in the near term as to whether, you know, that model is
12 making a reasonable representation of what we know today
13 about investor risk profiles. And so to say that well, you
14 know, we have a model that tells us things, relative cases
15 to each other, my response is well no, you don't know --
16 until you know whether your base case is reasonable, you
17 don't know whether your comparison of the base case to
18 another case tells you anything.

19 Secondly, as Ben said before, it's all about the
20 interest function. We know Ben has described modeling after
21 -- it looks to me like there were a couple of flawed input
22 assumptions that dramatically affect or could dramatically
23 affect the results for the vertical case in terms of the
24 amount of volatility coming out of that case.

25 And, in particular, when you model the vertical
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18895
DAV

268

1 demand curve case, he set the shortage price not at the CDR,
2 not at what we have today, but at two times the cost of new
3 entry, which is essentially two times the CDR rate that we
4 have today. So right there, whenever the vertical curve
5 case goes short, prices are jumping up to two times the CDR.
6 So right there you've exacerbated your volatility associated
7 with the case.

8 Secondly, there was -- at least back when we were
9 discussing the modeling during the stakeholder process, the
10 last set of runs assumed that new capacity offered into the
11 auction at a price below investment cost. So the model
12 assumes that new capacity is going to bid in at a price that
13 is below levels to achieve profitability.

14 So as a result, what happens is that clearing
15 prices come out at levels below profitable levels and, as a
16 result, the model then says well okay, investors are not
17 going to build new capacity because in the future they see
18 that prices are below levels that induce profitable
19 investment. So that forces the model into a bust cycle that
20 drives up prices in the energy market scarcity levels,
21 drives up capacity prices to two times the cost of new entry
22 and then, you know, creates a boom cycle. So the flawed
23 assumptions generate the outcome that you're seeing, which
24 is a lot of volatility in the vertical demand curve case.
25 And so frankly until we can get a model simulation that more
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18895
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269

1 reasonably reflects reality on the vertical curve case, I
2 don't think you can really say whether the reduction in
3 volatility from a sloped demand curve will actually produce
4 lower total costs.

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270

1 MS. COCHRANE: I'd like to switch gears for a
2 minute. We have some other topics that we'd like to explore
3 and we're running out of time. We will have --

4 MR. HOBBS: First of all, no benchmarking. If
5 I'm going to make a precise numerical prediction of
6 something happening in the future, benchmarking would be
7 absolutely key. That can't be done; I'm not going to claim
8 it can be done. That's why you look at an incredibly wide
9 range of assumptions. Among the wide range of assumptions
10 we looked at included different bidding behavior by the new
11 generation, ranging from bidding nothing to saying we're
12 going to put that in as a vertical supply curve to bidding
13 \$44,000 per megawatt, which is basically the net cost of new
14 capacity. When you take out expected energy and ancillary
15 services, John's right, that case should be considered. I
16 have considered it. I'm sorry I don't have time -- I could
17 have taken 15 minutes like some of the other speakers today
18 and gone through those, but I think I was merciful not to.
19 Sorry for the dig.

20 The other matter, the shortage price at CDR, we
21 did simulations with lower prices, the vertical curves do
22 even worse. You could push the multiplier on the CDR down
23 to zero times CDR, guess how much capacity you'll get then?
24 You'll get less capacity, more volatility because you have
25 less capacity, and you're in the range of high shortage

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18895
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271

1 costs. It turns out the vertical demand curve does not do
2 better from two times to one time.

3 All this will be documented hopefully in some
4 sort of filing eventually. I'm sorry I didn't get the
5 chance to talk about this today. I'll be glad to talk more
6 off-line with anybody who would like to.

7 MS. COCHRANE: At the end of the day, we'll talk
8 about next steps and opportunities for people to add more to
9 the record.

10 MR. HOBBS: By the way, I welcome suggestions for
11 sensitivity analyses. We've actually been dialoguing with a
12 number of people in this room about this, and I welcome the
13 analysis.

14 MR. KATHAN: I have a series of questions focused
15 on demand response. Particularly, I wanted to direct them
16 to Steve and Stephen and also to Tom, if you'd like.

17 The first thing I was struck by: you're both
18 retail providers, you're both providing demand response but
19 you're taking dramatically different opinions on the RPM.
20 I'm wondering why. Is it because your different type of
21 customers that you're serving, different types of
22 technology? Can you provide --

23 MR. WEMPLE: To clarify -- and I think Steve hit
24 it on the head -- the PJM ALM program, based on the current
25 penalty and level of compensation, is fairly unattractive,
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18895
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272

1 so we are not selling any of that. We're actually advising
2 customers don't sign up for ALM, it's not going to reward
3 you very much and you've got this huge stick hanging over
4 your head. We are very active in some of the locational
5 markets in New York where demand response is able to get the
6 full locational value and participate under special case
7 resources, and we find it very compelling to talk to
8 customers about the ability to hedge their own capacity
9 costs, which are a measurable part of their supply costs
10 that can be based on the New York capacity prices equivalent
11 of 2 to 2.5 cents a kilowatt hour just in the capacity cost
12 alone. That is significant for them, it gets their
13 attention and, you know, I would suspect it's perhaps the
14 different markets that we're operating in.

15 MR. FERNANDS: It may also have something to do
16 with our generation portfolios in New Jersey. People should
17 advocate for their business interests, and if you own a
18 significant amount of merchant generation in New Jersey, you
19 should be in favor of RPM.

20 MR. KATHAN: Following up, are your customers
21 ones that are large industrials who are interested in
22 responding in more of a voluntary or more of an ADRP, like
23 it is in New York, or are they ones that are involved in the
24 ALM?

25 MR. FERNANDS: I can expand a little bit more
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18895
DAV

273

1 about my particular group of folks. They range from
2 cooperatives and municipals that have air conditioning and
3 water heater programs that use it to reduce their capacity
4 costs. And traditionally some of them participate in ALM,
5 some of them use it to reduce their peaks and participate in
6 PJM's pilot program or have historically participated in
7 that. Some of them have bid in the day-ahead market and
8 some in the real time, both large industrial customers as
9 well as actually residential programs. So a fairly broad
10 variety in PJM.

11 I would agree with Steve that the capacity non-
12 performance rules in New York are much more favorable as
13 opposed to the penalty structure in PJM. I have a broad
14 group of clients in demand side response.

15 MR. KATHAN: I guess I wanted to get what Tom had
16 mentioned and I think what was earlier stated, the types of
17 technology that would be coming out inside of an RPM. Do
18 you believe there would be an increase, any increase in the
19 amount of demand response brought into the market if you now
20 have a four year procurement requirement. Under the various
21 outs you have, does that provide enough of an incentive to
22 invest in technology, invest in a longer-term investment?

23 MR. FERNANDS: Steve made a valid assertion.
24 People can essentially not participate in the markets and
25 then, on a very short-term basis, can opt out of the RPM and
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18895
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274

1 can look ahead four years and say okay, if I opt out of RPM,
2 opt out of the capacity market, I'll know what my avoided
3 cost will be for the next four years if they have some
4 relationship to a load-serving entity that allows them to do
5 that. There could be that opportunity. Just from the
6 clients I've talked to, I haven't found anyone that's like
7 that.

8 The Neenan study is probably the most
9 comprehensive, because it looked at New York, New Jersey,
10 and PJM. As far as a survey that I know of that goes
11 outside of the folks I know, everything I've heard in that
12 study indicated that no, it would really be a reduction in
13 demand side response participation. But again, that's based
14 on those sources.

15 MR. WEMPLE: And the point/counterpoint, I think
16 the Neenan study was looking at the four year forward.
17 Since demand response under the ILR program can participate
18 with three months' notice, I don't believe the conclusions
19 in the Neenan study are applicable to the PJM proposal
20 because they really focused on the older CRAM proposal.

21 In terms of the customers we work with, you've
22 got customers who can currently curtail because they have
23 backups already in their facilities, hospitals, financial
24 institutions with critical processes, those are the ones
25 that have virtually no lead time because they had that
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18895
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275

1 capability to begin with; there may be some internal wiring.

2 You have other customers with the right market
3 valuations and I think that comes from defining the
4 locational markets as well as having a rational demand
5 curve, so they have some consistency of revenue streams, are
6 likely to make investments in curtailable measures. We
7 actually buy curtailable measures from other suppliers who
8 are more creative than we are. There's one shop who
9 basically hands out movie tickets and sends an apartment
10 basically to the movie next door on hot days and curtails
11 that way.

12 (Laughter.)

13 MR. WEMPLE: Hats off to them. That's what
14 markets are all about. If someone can come up with a better
15 idea, I'm perfectly happy to buy the capacity.

16 MR. KATHAN: Anyone else? Tom?

17 MR. WELCH: I'll just say it seems to me one of
18 the intuitive advantages that RPM, with its forward
19 component and forward identified price, will bring is if I'm
20 trying to develop a demand product of this kind, I have a
21 price target to look at far enough in advance so that I can
22 develop a plan and sell it to somebody, you know, in the
23 three month ahead situation with some indication of what the
24 value of it is going to be. One of the impediments we've
25 heard is that people just have no idea how they'll be able

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18895
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276

1 to capture the value of demand if they develop some sort of
2 business plan around it and RPM provides a price signal for
3 a particular component of value they will bring into the
4 market that right now is absent in the much shorter term
5 market.

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18895
DAV

277

1 MR. FERNANDS: One of the struggles with that
2 concept, though, is that there's no one to sell it to. Yes,
3 you now can opt out, but all the load-serving entities have
4 bought their capacity or PJM bought on their behalf, all the
5 capacity. It's a question of, unless I'm my own load-
6 serving entity, some large industrial customer, my own load-
7 serving entity, and I can avoid the costs, if someone else
8 has already bought on behalf of mine and everyone else's
9 load-serving entity, that capacity obligation, I really need
10 to have something with my load-serving entity.

11 So, I'm served by PECO Energy, I'm under a fixed
12 rate with them, and I suddenly say, okay, I'm on a fixed-
13 rate tariff rate, and I say, okay, three months ahead, I can
14 do ALM. Right now, in ALM, I can trade, then sell into the
15 market, another provider can pick it up. It doesn't have to
16 be that load-serving entity.

17 The only value, if I decide to respond, is to
18 PECO, and PECO, in their rates, may not have that we're
19 going to pay you to do that, in fact, quite the opposite.
20 So, there are inconsistencies. I can go into that in more
21 detail, but I have a feeling that you don't want me to.

22 (Laughter.)

23 MR. O'NEILL: Steve, you said something very, I
24 think -- at least it struck me as interesting -- the reason
25 why you and Steve differ on your positions, is because you

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18895
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278

1 have different current portfolio positions.

2 How much of this is about current portfolio
3 positions, and really not about the long-term health of the
4 PJM market?

5 (Laughter.)

6 MR. FERNANDS: I'll let you give the last word on
7 this one, if you want.

8 MR. WEMPLE: Our affiliate owns 600 megawatts of
9 generation in PJM, and our load positions are in excess of
10 that, so if I were to argue for a higher capacity cost
11 tomorrow, it will cost my company more to hedge my load,
12 than I would get from my generation side.

13 Our positions, what I think we've always tried to
14 advocate for, we want a solution that's going to work in the
15 long term and bring everything together. We can't focus one
16 month, six months, or even a year down the road.

17 We've made a corporate investment to sell retail.
18 We hope to be around doing that for the next 20 years.
19 We've made a corporate investment to invest in generation,
20 and I hope those plants are going to be around for more than
21 20 years.

22 We're in it for the long haul, Dick.

23 MR. FERNANDS: By and large, my clients tend to
24 be municipals, cooperatives, people that are also going to
25 be around for the long haul, and tend not to react strongly
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18895
DAV

279

1 to short-term impacts.

2 That being said, just as you're analyzing the
3 comments, although everyone is supporting reliability here,
4 it seem coincidental that a lot of the utilities that have
5 resources east of the Eastern Interface, view reliability
6 being served most economically, one way, and people that own
7 physical resources west of the Eastern Interface, view
8 getting to that same point, a different way.

9 Also, although most load east of the Eastern
10 Interface is served by market-based rates that get adjusted
11 each year, and, therefore, increases or decreases in prices
12 get passed through to the customers, as opposed to swallowed
13 by a load-serving entity with long-term contracts, the
14 exception, of course, being municipals and cooperatives,
15 that customers don't just switch; they stay long-term, and
16 if their costs go up, they have to pass those on to their
17 customers.

18 MR. BANDERA: Steve, just a quick question: You
19 brought up the position situation and how that might deter
20 your incentives to support or be against this. Would your
21 situation potentially be one where you're short on capacity
22 for your clients, and, if we switch to RPM, that would work
23 against your situation?

24 MR. FERNANDS: Our clients -- again, my comments
25 were for us as a consulting company, as opposed to any of
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18895
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280

1 our specific clients -- they range the spectrum in terms of
2 where they're physically located across the systems. We
3 have folks in Chicago, we have folks in the Delmarva
4 Peninsula, and most everywhere in between.

5 We have people that have capacity positions that
6 are exceptionally long and we have people who have capacity
7 positions that are exceptionally short.

8 So, we really do have a variety of positions.
9 Most of our people both have physical generation, as well as
10 financial contracts that make up their portfolios, so we
11 don't necessarily have one specific dominant strategy, per
12 se.

13 MR. SCOTT: As one of the clients and one of the
14 cooperatives that has a great deal of generation, mixed
15 baseload, new coal, CT, sometimes with that buyer, sometimes
16 we view it that we can manage our risk.

17 We look at RPM as kind of a non-market or
18 administrative solution, and if we're going to solve
19 resource adequacy with an administrative program, then,
20 okay, let's do that. I'm not suggesting integrated resource
21 planning and segmenting by asset classes, but if we're
22 really going to have an administrative solution, let's do
23 one. Otherwise, let's facilitate a market-oriented
24 solution.

25 I mean, we and others who build, and anybody else
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18895
DAV

281

1 in this market, can already cap their exposure. The net
2 costs of merely creating the CT in a period of surplus here,
3 automatically, arbitrarily, and administratively riding up
4 the value of capacity, you haven't exactly done me a favor
5 here that I can't already do for myself.

6 So, it's a view, it's a philosophical view that
7 it's not a healthy market design, from a long-term point of
8 view. We own these assets on our balance sheet, and we have
9 a long-term interest, we have no reason for being
10 shortsighted and artificially impeding the value of
11 generation or interfering with the adequacy of the system.

12 MS. COCHRANE: Thank you all very much. I know a
13 number of you have travel arrangements, and we have the room
14 only until 5:00, so I don't want to run too much over that.

15 It's been a long day. We've addressed a lot of
16 very difficult issues. Don't walk out yet, Joe.

17 (Laughter.)

18 MS. COCHRANE: I'm not done yet. You might want
19 to hear this.

20 At any rate, we had set aside a relatively large
21 block of time in the afternoon that we'd hoped to kind of
22 recap. Well, we'll have to do that real quickly now.

23 To sort of recap a bit about what I think we've
24 heard as points of agreement today, there's a lot of
25 disagreement, but I think there is also some points of
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18895
DAV

282

1 agreement today.

2 For the most part, people agree that the current
3 capacity construct isn't meeting everybody's needs, and
4 perhaps needs some changes.

5 I think we heard a lot of agreement that there
6 are changes that are needed to the transmission planning
7 process, and I think there are some statements by PJM and
8 some changes that have already been made, and perhaps more
9 can be made to integrate transmission planning with capacity
10 markets and with demand response and other aspects that
11 we've heard.

12 There seems to be a general agreement, for the
13 most part, that there needs to be a look at the locational
14 needs of different parts of PJM's system and in designing
15 capacity markets to address the shortages in certain areas.

16 There may be more areas of agreement. I think
17 there are a lot of areas of disagreement. One thing I'd
18 like to do is to respond to a statement that was made by Tom
19 Welch and others that support the RPM. They have said --
20 Tom, you said that you think there's sufficient
21 understanding of the RPM proposal, so, you know, we should
22 go ahead and file it at the FERC.

23 I think there is understanding of the proposal,
24 but there's not necessarily agreement with it, though. And,
25 as Commissioner Brownell said, we're here to make tough

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18895
DAV

283

1 decisions, and we recognize that we don't get very often,
2 things before us that have complete agreement.

3 There is disagreement on a lot of aspects, and
4 we're here to make a tough decision. We'd rather have
5 something come to us that has a bit more consensus, so that
6 we don't have to make as many tough decisions.

7 And we don't want to have something that is going
8 to have to spend a lot of time in hearing. You all are well
9 aware of the experience that has recently completed with
10 your northern neighbor. That was a very expensive and time-
11 consuming effort, and it's something that we would like to
12 avoid, for the most part.

13 I hate to say this, but we urge you to go back to
14 your stakeholders. We would like you to file comments.

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18895
DAV

284

1 I also realize that there are people who wanted
2 to speak today, obviously we had a very full day and we
3 weren't able to accommodate everybody who wanted to speak
4 today. But if you could file comments to us within 20 days
5 under this docket number, and especially if you wanted to
6 address some questions that were raised that maybe you'd
7 like to answer.

8 What we would especially like to know is areas of
9 agreement, suggested areas of compromise, ways, directions
10 that the debate can be carried a little bit further. We
11 understand and recognize that the PJM board is looking at
12 this record. They have said, in Phil Harris' letter, I
13 think, to stakeholders that they were looking to see what
14 the record is developed here. That's primarily why we're
15 asking for the comments and suggesting that you try to work
16 through and develop this proposal further.

17 Did I miss anything, Derek?

18 MR. BANDERA: No.

19 MS. COCHRANE: When I said file in 20 days, I
20 looked on my calendar, that's July 7th. The reason why
21 we're saying 20 days is we want you to have the opportunity
22 to get the transcript. As mentioned in the notice, you can
23 get the transcript from Ace Reporting. I guess if you gave
24 him a card, he could make sure that you could get it
25 quickly, or there's also a phone number in the notice, or

26

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DAV

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1 you can call and you can also get it. Otherwise, we get it
2 through our contract. We'll put it on our new E-library
3 system seven days after we receive it from them. There's a
4 bit of a delay if you want to get it for free off of our
5 website. If you want to get it quickly, contact the Ace
6 reporter, he'll get it for you.

7 Finally, just as a procedural matter, my attorney
8 has gone but left me a note there are a couple of more
9 dockets -- proceedings that were mentioned off to the side.
10 We tried to add a couple to the notice that we thought might
11 get mentioned, just to cover ourselves. There were a couple
12 more that were mentioned that we'll also add to this
13 proceeding. One is the RT01-2 docket. PJM, also a New York
14 ISO proceeding, ER04-1144, having to do with their planning
15 process. We may also put the AD05-3 proceeding in this
16 because of the discussion about the project, Mountaineer,
17 from the coal proceeding.

18 That's my wrap-up. Almost made it before 5:00.
19 Anybody else have anything they'd like to say?

20 (No response.)

21 MS. COCHRANE: I very much appreciate the
22 discussion and patience with me as I tried to move things
23 along. Thank you very much.

24 (Whereupon, at 5:05 p.m. the conference was
25 adjourned.)