BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Number

CAPACITY MARKETS IN THE : PL05-7-000

PJM REGION :

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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

P R O C E E D I N G S

(9:05 a.m.)

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

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

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

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

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

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

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

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

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

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

Why are we doing this? Is this to rubber-stamp? Is this to force solutions? Is this to do a variety of things?

So I want to be very clear from the outset that this is to have an open discussion of what has been proposed and what some of the interrelationships are to other issues, to make sure that we're working with a common set of definitions.

It's extraordinary to me, the number of times we have very technical conversations and everybody's talking about something different. So, let's just, at the very least, make sure we're talking about the same things, and then to get out where we can find consensus and where we cannot.

We don't expect, in something that involves huge amounts of money, to get 100-percent consensus. That's why we get paid the big bucks.

But I think it is important to be as creative as we possibly can, in coming up with ideas, either the one that's on the table or alternatives or different pieces, to see if we can bring some value to the customers.

I don't think there's anyone in the world who thinks that capacity markets, as they exist today, are sending the appropriate economic signals. We can also debate that, in a perfect world, we might not need capacity markets, but we are not in a perfect world.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

With the absence of a forward-looking capacity price and market and price signals, a relatively smooth equilibration, as relatively smooth process, as a likelihood of getting to the desired level of reliability, is quite unlikely. It is, in fact, likely to be quite choppy, quite unstable.

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

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

(Laughter.)

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

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

Last year, price was less than $20 a megawatt-day. Another result of that, for the overall market -- and, again, it's not necessarily an irrational outcome for the overall market, is that net revenues are down.

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

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

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

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

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

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

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

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

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

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

MS. COCHRANE: Betsy, your turn.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

MS. COCHRANE: Thank you for your comments.

The next panelist is Tom Shaw with PEPCO.

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

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

Our three regulated businesses, PEPCO, Delmarva Power and Light, and Atlantic City Electric, deliver approximately 12,000 megawatts to 1.8 million retail customers here in the mid-Atlantic region. We have an ongoing obligation to provide reliable service to our customers at reasonable cost. We rely upon PJM to provide a reliable regional bulk power system. We do not want PJM to start focusing on short-term price impacts at the expense of long-term system reliability. It is basic physics that transmission has no value without generation and vice-versa; the two are both critical components of a reliable bulk power system. They're not independent alternatives to each other.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

So to take that existing circumstance and to regulatorily mandate a revenue stream on top of it is not, in our opinion, just and reasonable and cannot be squared with the Federal Power Act. What we do know is that PJM's total market construct, inclusive of the energy piece and ancillary services piece and capacity piece, has attracted new investment, continues to attract new investment, has resulted in a systemwide reserve margin in excess of 25 percent. So as we analyze the issue, we can't lose sight of that fact. We can't allow a particular locational issue that has begun to arise to call into question the core components of that construct.

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

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

Thank you.

MS. COCHRANE: Thank you, Bob.

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

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

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

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

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

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

What are the goals of the capacity construct? To assure an appropriate level of investment and the optimal mix of generation capacity within the system to assure availability of supply and reliability given the long lead times of construction and to ensure the ability of the system to meet demand given its inherent fluctuation and uncertainty and the non-storability of power and to encourage a robust long-term bilateral forward market for power supply for long-term price stability ensurance.

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

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

However, one failing of the current integrated system is its inability to encourage the correct mix of generation assets for the long term. Most of the new assets built have been smaller-scale natural gas fired intermediate and peaking generation assets. What is long overdue and sorely needed is investment in new baseloaded large-scale generation assets utilizing economic and abundant fuels.

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

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

PJM has promoted the theory of universally-deliverable generation but has not planned and constructed the transmission system to make it a reality. If the universal deliverability concept had been honored in reality, rather than in theory over the past seven years, there would be no concerns for reliability in New Jersey, the Delmarva Peninsula, or any other part of PJM. Indeed, the entire justification of RTO formation and industry restructuring is to capture the efficiency and economics of the integrated electric system for the benefit of end users through competitive markets. But we have not built a competitive market yet. The principal broken part, the transmission system, has yet to be fixed.

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

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

Thank you for the opportunity to make these comments.

MS. COCHRANE: Thank you.

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

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

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

The situation in which we find ourselves is the desire to achieve a robust reliable network during and after the transition towards integrated competitive wholesale and retail markets. In that transition, we face concerns about long-term reliability and the investment to provide reliability, a perceived need for a centralized resource adequacy planning process, immature integrated physical and financial wholesale markets, immature demand side participation in both wholesale and retail parts of the value chain, and reluctance to allow wholesale energy spot price fluctuations to signal investment opportunities to entrepreneurs.

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

A capacity market construct with locational product definition is one way to deal with the regulatory distortion imposed by price caps. In many ways, it is inferior to integrated forward energy markets, which do a better job of picking that optimal resource portfolio. And, of course, optimal resource portfolios do change over time. The information requirements to pick optimal resource portfolios in a centralized manner are large, as the knowledge required to discover the optimal resource portfolio is diffuse and distributed among market participants, customers, and entrepreneurs who are the agents in the electric power network. The intertemporal nature of the problem and the time that some resources take to build mean that the market process in question has delivery commitment in the future, which means integrated spot and forward energy markets.

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

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

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

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

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

(Laughter.)

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

Thus, I suggest the RTO capacity market policy should include equivalent participation of generation, transmission demand, and new technology resources, transparent rules for the capacity markets retirement when it is no longer needed, working diligently to decrease the transaction costs hampering the development of integrated spot and forward markets for electricity products, which has been done in places like Australia. That can provide useful examples and lessons.

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

Thank you.

MS. COCHRANE: Thank you, Lynne.

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

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

Before I begin, I'd like to thank the Commission for the opportunity to address the issue. We've written a series of reports on the capacity markets issue since the early part of this year and have had many conversations with investors on the topic. Copies of our reports are actually located in the back. We did bring a handful of them and I'm happy to send them to you to post my comments here if you're interested in looking at our comments. Let me summarize our current views in five major points.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(Laughter.)

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

I started off in pretty much the same position where Joe Bowring did. If you have a mandated energy cap and a mandated reserve margin reliability, you're going to be short money.

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

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

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

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

In the abstract, one might argue that both the status quo for the PJM capacity market and the RPM proposal from PJM, can meet at least the requirement of replacing the missing money.

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

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

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

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

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

Alternatively, what we've been presented with in the RPM design, is an explicit design intended to reduce and remove these areas of risks, send the proper price signals and incentives, via locational pricing and new transfer rights, while leading to a more stable pricing and greater likelihood of maintaining the needed level of adequacy resources, and in turn, lowering costs for suppliers and load.

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

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

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

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

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

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

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

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

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

None of the other proposals we've heard of, the status quo or any of the alternatives being discussed, have the property of putting these two elements in sync.

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

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

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

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

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

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

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

RPM essentially, through the use of the demand curve, the downward sloping demand curve takes away this volatility and these types of risks. The cost impacts are very clear. We're talking billions of dollars of difference. We're going to have a presentation later from Mr. Hobbs that may go through some of this, but the earlier results in January show about a $30 to $50 per peak kW year difference in prices. Think about that in the context of a 150,000 megawatt system; we're talking billions of dollars of potential equilibrium price differentials per year. There's a huge amount of money associated with the risks that Brian is talking about. This occurs assuming no change in the cost of funds.

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

The final comments have to do with the transition to an energy only market. One of the mechanisms within the European design is demand curves are set based on the net cost of new entry. It has a trailing five-year mechanism to subtract out from the cost of new entry the average margins that are earned. That's an incredibly powerful tool for energy market mitigation which we might also want to talk about. But one of the other attributes that it has, if we choose to use it, is that by raising the price caps over time presumably the netting margin will go up and the capacity market could atrophy on its own.

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

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

MS. COCHRANE: Thank you, Roy.

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

Derek?

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

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

As I stated, the universal deliverability concept, that has been on the books for many years but we've never achieved in reality, should alleviate to a great extent the threat of sudden retirements of assets by allowing other similarly-economic assets to deliver to the load that is now stranded by the retirement of some asset, thereby eliminating the reliability problem.

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

MR. WEISHAAR: Ditto.

(Laughter.)

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

MR. BOWRING: I think a lot of what Pat said makes sense in part, that is, clearly it does make sense to plan the system as a unified whole. It clearly makes sense to think about transmission investment as well as generation investment. But at the same time, it does not make sense to ignore the facts we're facing right now about investment in capacity and investment in new generation. Deliverability still remains an objective and part of the PJM planning process. PJM has recently moved towards extending the length of the transmission planning process as well. Steve Herling's going to talk more about that this afternoon. But I don't think anything Pat said suggests that we don't need to resolve the capacity market design issue now.

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

The issue still becomes assume that you build all the transmission you want -- do it irrationally, spend too much on transmission at some point. All we're doing is delaying the point at which we will have to deal with this notion of the missing money and the kind of compensation that's needed in an equilibrium system to keep people coming in. If you want to delay this two or three years, that's fine. If you want to build excess transmission, that's fine. But we're still going to get to a point where, under any view of the markets, under any construct if we're going to cap prices and have an assured or mandated reliability level, we're going to have to pay for the capacity. At issue is efficiency. If all that would happen with excessive transmission construction is that we would see the locational differentials go toward zero, we'd still be operating under a boom/bust system or a demand curve system that is going to be necessary to bring the new capacity into the market.

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

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

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

There are going to be times, as time goes forward, that your RTEP, your transmission planning, is not perfect, and you're going to have localized problems that will develop. I think RMR contracts should be viewed as a least-cost bridge between the development of the locational problems and the catching up of the transmission system construction. I think that is infinitely more desirable to me as a load-serving entity representative -- you know, the guys who write the checks for all this -- than nuking the market by rewarding all generation owners for local reliability, points-to-point problems.

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

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

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

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

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

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

MR. TIGER: If I could follow up?

MR. SHANKER: I'm sorry. Something that I'm sort of uncomfortable letting stand is the notion that RMR is sort of beneficial when it has to occur, it's least cost, and we shouldn't have windfalls to other people in a clearing situation. Let's take them a piece at a time. I think Joe alluded to this about the inefficiency of RMR.

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

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

There's no magic to this. Everybody needs to average that net cost of new entry. Every type of generation -- baseload, peaking, intermediate -- has to get it over the business cycle to make the adequate returns to stay in the market. If you're uncomfortable with the notion that some people are going to get high prices when things are short, that's only because you failed the hedge in a portion of the cycle where you could pay the long-term average cost, and everybody would be at equilibrium for that.

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

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

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

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

When we talk with investors about looking at forward generation, what you find is a very strong reluctance to build generation. When there is uncertainty over contracting, there's no more of that view that if you build it, they will come. Instead, there is a view that, due to the high level of uncertainty in contracting, and due to the inefficiencies of a forward market, which hasn't evolved sufficiently, as Professor Kiesling said, you find that investors place a high premium, a high risk to equity, and risk to capital, when they're looking at the space. As a result, if they do look at the space, they'll do it only from a distressed asset standpoint. So the investors that are looking at the space and picking up current generation assets tend to be a more stressed asset investor, vultures, speculators, folks looking at picking up an asset on the cheap, and they're hoping at some point the supply and demand equilibrium catch up before people realize it, and then they flip the asset. They'll sell it to somebody else. You have this high degree of asset turnover phenomenon that's going through markets at this point.

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

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

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

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

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

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

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

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

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

MR. MARGOLIS: One of the things that's promoting the RMRs is retirement decisions. The resource planning process we're trying to forward-look 5 or 10 years. The retirement decisions are very short-term notifications. Is there a way to get around that disconnect?

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

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

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

MS. MOLER: If I might comment, I think that this overcommit thing -- I'm sorry to be a one-song pony, but it's really an important part of the picture. It puts the price out there. It lets generators decide whether they want to come to the table or not. It puts the price signal out there for potential developers. Right now, there are so many developers that have been burned, substantial amounts of money, that they're very, very weary of coming back in the marketplace.

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

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

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

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

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

The question I have is, if it's really just for those very serendipitous events, or events that you can't plan for, that's one thing. But if it's moving to suppress scarcity rents, that's another. And I'm wondering would you use these tools simply to suppress the scarcity rents.

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

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

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

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

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

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

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

MR. BOWRING: No.

MR. O'NEILL: Who does?

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

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

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

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

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

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

MR. O'NEILL: The point I was trying to make was, or one of the points, is that if you use the RMR process to overmitigate or oversuppress prices, it becomes a tool for people to use that isn't what it was intended.

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

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

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

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

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

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

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

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

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

(Laughter)

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

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

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

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

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

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

(Laughter)

MR. McCULLAR: Only the western part.

MR. SHAW: We're building a transmission line, basically down the length of Delaware, as we speak, and we are in the final stages of completing one down the southeast coast of New Jersey. The decisions that led to that were very much like one might imagine. You look at what the alternatives are, and you file with PJM. Eventually, it gets into the regional transmission expansion plan. Those are in one case 90 miles, in one case 70 miles building transmission. I've been responsible for building power plants. It's not getting any easier and it is very difficult.

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

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

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

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

I'm sure they have all the scheduling things. Steve is able to talk more about that than I can, but those are not the sort of typical, at-risk merchant structures here. Those are going to rate-based activities that are being designated based on specific reliability violations. They are designed explicitly to fix the type of problems that would otherwise necessitate the RMR requirements in the presence of unknown or uncertain retirements of units.

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

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

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

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

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

(No response)

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

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

A company -- I don't know who they are -- called HP Trading submitted some comments in another docket about a proposal they have on the Beddington Black Oak constraint that would increase capacity by 1400 megawatts. I need to understand why those aren't happening, because I think unless we address some of those issues, we'll be back at the table wondering why things aren't working.

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

COMMISSIONER KELLY: No.

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

David?

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

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

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

The time frame, the types of things we've been discussing tend to take from six months to a year. So usually in the time frames that we tend to operate in, in this space, when you would like to have things pass yesterday, that's sort of long lead time to do experiment often precludes there being necessarily something that folks want to pursue.

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

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

The beautiful thing about experimental economics is so much decision-making and so much of our rationality is so deeply embedded in our subconscious, and you can't program a computer to access that. When you put people in an environment, and you tell them they get to walk out with whatever they earn, they're going to get in there and scramble for every penny. They'll find flaws you didn't know were there. They'll find strategies you couldn't have predicted, and that's the true benefit of the methodology.

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

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

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

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

For example, it's fairly common to see

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

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

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

MR. CHIN: I think the factors that primarily determine investment in this space are looking at supply and demand relationships, and where the projected power price spikes are most likely to occur are capacity market structure; basically set incentive a little bit richer, but in terms of directing a capacity market structure to favor certain types of technologies over another, I think that would depend on the details of the capacity market structure. Certainly, if you have some sort of quit-start mechanism, incentive mechanism, some sort of generation fuel provision that favors that technology, obviously, the investment response would be commensurate. But right now, by and large, the vast majority of the investment incentive appears to be the anticipation of some tightness off of what is right now a very distressed asset valuation scenario.

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

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

Brian, you emphasized long-term contracting as well. Do you have any thoughts on how the proposal that is before us would do in terms of long-term contracting, and, specifically, the issue of if you do it four years out, maybe it gives a bigger piece, with PJM being the POLR; versus if you do it one year, maybe LSEs buy more. I don't know if this is the type of thing that experiments can answer. My guess is it would be physical because it's a long-term system. If you have any thoughts on that?

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

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

A similar scenario would be if you look at the

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

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

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

(Laughter)

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

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

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

MR. SHANKER: One of the things, Harry, is that it's the background against which people will be contracting for a long time. There's still the case that proven participants in the market, particularly those that have long-term load obligations, will enter into long-term hedges if they're reasonable about it. The question is, is it more likely to encourage somebody to hedge their risk in a market where there is some volatility, but the volatility is possibly predictable and there's a reasonable forward curve to work against, or is it more likely will hedge where there's huge volatility and it's unknown?

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

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

(Recess)

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

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

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

The PJM board recognizes that the transmission planning process we have today needs to be revised to focus more on long term and to focus more on the needs of the competitive market as opposed to only on reliability. We have recognized that, and have a stakeholder process to get that moving as quickly as possible; however, transmission expansion alone isn't going to solve the problem. You need an integrated solution that integrates integration demand response and transmission. Essentially, that's what we have with RPM.

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

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

The point is there's substantial transmission infrastructure that can be built on that kind of time frame. The fact that the RPM has incremental auctions where you can bid a position on a forward basis, and you can adjust that position each year as you get closer allows, again, that same kind of dynamic, if you will, for somebody to take and say I will build. But if they run into problems, they can get an alternative solution to jump in. That kind of dynamic, actually, is a meaningful, competitive transmission investment model, which is what we don't have today.

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

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

So it's not unrealistic. You have debate, what I'd call fundamental disagreements. We had over 100 meetings to talk about this. We made modifications as we went forward. I attached those to my documentation. One of those documentations was actually substantive. We actually added the transmission investment participation. Again, there are different stakeholder views, and consensus couldn't be achieved. It's obvious to you, probably today from the first model, that there are substantive disagreements. That's why we're here today.

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

As I'll go through what I'll call the three key elements of RPM. We have the locational capacity pricing. Again, that was necessary to ensure capacity pricing is consistent with local reliability, the granularity of the locational elements. Essentially, we were talking on the locational pricing debate, I was sitting here probably at least before some of you. I was talking about should we have a single clearing pricing; should we have locational pricing? What we learned in that debate and what we learned in the reality of the market is that implementation is that pricing has to be consistent with the physical reality in order to make sure that the pricing doesn't have what I'll call fundamental flaws.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

MS. COCHRANE: Thanks, Andy.

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

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

(Laughter)

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

I liked the opening comments we had today. WE are not in a perfect world; we do not have a perfect market. But where we are right now is a world that's evolving. We are trying to get into a market world, and moving from vertically integrated monopolists into a competitive mode. We have economically rational behavior that we're seeing from folks; contracts, as Joe Bowring said, versus locational capacity needs, so these need to be addressed.

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

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

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

The EITCC proposal, if you will, is philosophically a bit different approach. We are focusing on resource and infrastructure adequacy rather than revenue adequacy for a particular set of assets, and we want to provide the infrastructure to get the right resources built in the right place, at the right time. There's a capacity component for resource adequacy and trying to maintain market processes where resources and loads can rationally transact.

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

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

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

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

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

EITCC. We viewed it as an incremental change to the current construct. We have system and local requirements. The system, installed reserve margin, and local obligations are both identified three years ahead of time, based upon engineering studies and planning analyses. The load-serving entity's obligation is increased from one that is daily to a full year. There's deficiency penalty removing from a penalty that would apply only an interval to an annual basis. The penalty maintains the current capacity deficiency rate, which we believe is a premium above the net cost of new entry. Visa items help provide information. The deficiency penalty helps provide inspiration for folks to perform and meet their obligations.

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

Transmission attributes include expansion of a planning horizon of what we're supposed to be doing five years to either 7 to 10 years, and we're happy to talk to PJM and the transmission owners about how to do that. I'd like to retain five years for the short time frame requirements and proactively accrue upgrades based on unit retirement assessments. The transmission panel will talk a little bit about that this afternoon, as to how, indeed, that can be done. Just because it's hard doesn't mean we shouldn't try to do it. It incorporates the local capacity premiums in a cost benefit analysis via the current economic planning process. It addresses the local deliverability areas.

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

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

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

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

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

First, RPM is a non-market administrative solution that would prevent the formation of active and liquid bilateral market, where both load and generation can hedge. PPL's major concerns are that RPM preempts short-term markets, which increases the risk of doing long-term deals. RPM increases the uncertainty associated with trading five years and beyond, which will also impede the long-term deals. And RPM poses significant credit issues, such as the need to post collateral for five years, which would limit the counterparties in the market, thus, increase costs. RPM has limited pricing points, one base-residual auction and up to three incremental auctions. All auction results will be ex-post pricing. A liquid bilateral market would have continuous price discovery and provide ex ante pricing.

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

RPM would not be conducive to new investment as claimed by supporters. Generation must have a signed interconnection service agreement in order to participate, possibly missing the deadline for the base residual auction. The one-year commitment four years out would not be meaningful to a new generator who needs to recover its cost over many years. In fact, because a generator needs to lock in year four's price today, RPM introduces certainty that should factor into a generator's offer, which ultimately may increase price. Further, a one-year binding financial commitment four years out is no more binding and provides no more assurance than a firm, liquidated damages provision in a bilateral contract.

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

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

Secondly, set the obligations forward. PJM should set capacity obligations and establish LDAs, based on the assembled information, four years prior to the delivery year.

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

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

Under PPL's proposal, price would be discovered continuously through bilateral contracting. Under PJM, most capacity would be ex-post price at the time of the base residual option, and there would not be any short-term liquidity, aside from a few RPM incremental auctions. Under PPL's proposal, the ability to forward contract would allow multiple use to be hedged t negotiated prices that reflected the dynamic nature of the RTEP and changing generation supply. RPM would only allow load and generation to hedge one year and then administratively set price. RPM, as proposed, will make it impossible for liquid bilateral markets to develop. It only gives the illusion of providing the forward commitment for generation that PJM so desperately seeks so it can plan transmission adequately and avoid RMR contracts.

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

MS. COCHRANE: Thank you, Tom.

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

MR. OTT: Again, I think the debate is not -- I think if you look at a one-month auction, a one-year auction, a four-year auction, essentially the difference is when you run the auction and when the commitment must be satisfied, as opposed to who is taking ownership or dominating the market. In other words, in either case, PJM is simply running an auction that matches the buyers and sellers for the residual capacity that hasn't already been contracted for.

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

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

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

That's as binding, if you will, as clearing in the RPM auction. The fundamental difference is if you set that forward commitment four years ahead, then 100 percent of the generation I need for reliability is set. Now I know, essentially, what the reliability needs of the system are or how they're going to be satisfied. That assists the forward-transmission planning process so that we know what's going on.

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

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

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

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

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

The fundamental concept of saying that you can have a voluntary auction as opposed to -- as you said, essentially, you don't have all the information there to do the voluntary auction. That's the critical piece. You need all these commitments to come together at some point, certainly in order to make this function.

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

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

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

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

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

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

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

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

MR. O'NEILL: If their promise to make the bilateral commitment work didn't materialize -- one year is probably too late to make sure that the commitment doesn't --

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

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

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

MS. COCHRANE: I was going to ask Ed and Tom if you'd like to respond. I guess I thought -- Ed, could you respond to what Andy said about how you wouldn't have basically enough of the information coming out of a voluntary auction that they need to be the ones doing that because they have all of the information as far as transmission planning.

MR. TATUM: Thank you.

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

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

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

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

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

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

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

(Laughter.)

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

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

Now if you would do something to fix the IRM problem and the vertical demand problem -- like the four-year demand curve, you would put in a locational requirement as we believe you would create the environment for active, short, medium and long-term bilaterals, then I think you have a market structure that would be conducive to investment. You have a predictable revenue stream, somebody can look at that and say over the long haul I believe I'll get my money back and they'll invest in that market.

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

MR. HYZINSKI: Yes.

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

MR. TATUM: No, sir.

(Laughter.)

MR. TATUM: You got Tom right, though.

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

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

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

The other difference that we've got going on, this coalition has, is that we do not at this point subscribe to the demand curve. The major reason we do not subscribe to the demand curve is because, as far as the trade-off between the supposed reduced volatility, we see a very high price to pay for that reduced volatility. We think there is a certain finite pot of dollars that we as a nation have to invest in certain things and the consumers and the folks that pay us to supply them electricity have a certain limited supply of funds. If we have to invest in something, we want to invest in infrastructure and transmission, as well as needed generation locally.

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

MR. TATUM: Absolutely.

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

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

MR. O'NEILL: Have you changed your position from before? My understanding before was that you were going to have zones that really were not physically compatible with the actual reliability of the system and then you were going to clear the market and use RMR contracts to clean up the mistaken belief that you have too large zones. Have you changed since then?

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

(Laughter.)

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

MR. BANDERA: You don't think it's necessary for PJM to know four years ahead exactly what generation units are going to be there and you don't see the need to link those -- that transmission planning and the generation identification four years forward?

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

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

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

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

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

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

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

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

MS. COCHRANE: Just one more question.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Is that a short-term issue; is that a long-term issue? What is the time dimension of your concern?

MR. TATUM: Yes.

(Laughter.)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

AFTERNOON SESSION

(1:20 p.m.)

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

(Pause.)

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

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

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

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

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

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

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

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

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

RPM specifically provides for an opportunity for transmission to compete with generation and demand to resolve the capacity shortages, locationally, as we move forward, and, as we've seen, our experience over the last seven or eight years with deliverability, indicates a need for granularity in terms of how we evaluate the problems and how solutions are going to be provided to resolve the individual problems and constraints we face.

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

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

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

Obviously, we have a 90-day period during which we can evaluate, but that really doesn't give us much opportunity to do anything other than the RMR solution that we've been talking about.

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

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

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

In this instance, the transmission solutions are just going to take a number of years to put in place, but if the generation capacity was given a locational valuation, if it's critical to have generation capacity in a particular area, and if capacity was valued accordingly, then the existing generation, if it is viable for the long-term, they would have the incentives to keep those units in a state that they can participate in the markets for the long haul.

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

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

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

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

The changes we made to the planning process, have to work with RMP. If we change the planning horizon, the certainty issue, the longer-term commitment, becomes even more critical.

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

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

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

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

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

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

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

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

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

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

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

The existing capacity construct should be modified to integrated transmission planning into the capacity planning process, which I think Steve was mentioning.

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

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

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

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

AEP strongly believes that the capacity market design must consider the fact that there are vertically-integrated utilities where generation is directly tied to serving the load. Our customers do not pay market prices for their commodity supply. What they pay is an embedded cost based on the installed cost and the operating cost of our units. The vertically-integrated units in a regulated environment continue to plan resources in an integrated way, developing least cost solutions that assure customers our needs are met in an economic and reliable manner on a long-term basis.

In our short stint in PJM -- we're relatively the new kid on the block, or one of the new kids on the block -- I've seen a lot of progress in PJM attempting to really integrate the markets, the transmission, through the RTEP and through the demand response program, but they do have a way to go.

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

Another way to say this is a vertical demand curve that's set at the IRM. We believe the potential capacity problems in certain PJM areas could be alleviated by reliably integrating resources within the entire PJM footprint through adequate transmission.

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

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

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

We would urge PJM to consider modifying the existing capacity construct to address regional needs through the stakeholder process using RMR as a short run solution. Ed Tatum earlier today indicated that PJM has come a long way in this process. I believe they have as well, but I think we need some more time to talk about possible solutions. ODEC has a proposal that goes a significant way in meeting our needs.

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

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

That's the end of my prepared comments.

MS. COCHRANE: Thank you, Craig.

Our next panelist is Laurie Oppel with Navigant Consulting.

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

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

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

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

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

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

Furthermore, the assumptions are inconsistent between setting the capacity requirements and planning the transmission grid. The IRM studies do not consider retirements or addition of generation more than one year out. The planning studies consider only a limited number of scenarios. When you're looking at a five-year and 10-year horizon, clearly one needs a crystal ball.

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

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

Unfortunately, this deterministic methodology of transmission planning has not served to promote transmission development to preserve or enhance the competitive energy markets.

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

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

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

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

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

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

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

Cost allocation for transmission investment;

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

Thank you again. That concludes my comments.

MS. COCHRANE: Thank you, Laurie.

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

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

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

Some of the things we must understand is what was talked about earlier today, the concept of universal deliverability. What does that mean? In PJM, we have major interface limits, west central and eastern limited around the 7,000 megawatt area and 30,000 megawatts of peak load in the east. It's very obvious that every load in eastern PJM cannot buy Western Kentucky coal. So if universal deliverability means I am a load in one node and I wish to be able to get generation from anywhere that is cheapest. That's now how the transmission system was built. If you wish to reinforce the transmission system in that way, you're talking three or four times what it is now.

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

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

It's exactly as Roy spoke about. If you look at the market, you're undercollected. As a generation owner, you can't live undercollected a long time as a long-time PJM member. And the fact that PS is responsible for the load and PS is responsible for the generation, we probably kept those units online longer than anyone else would and we believe that we would put into our RMR contracts -- it makes this a more pertinent issue that needs to be solved.

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

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

In fact, two of the units we requested RMR status -- and we'll talk about what that really means, requested RMR status -- hadn't run in the last two years. So how people said why don't you collect your money on LMP, they were never ordered on by PJM -- because you've got to remember there's a 20 percent reserve margin in that area. If you have cooler weather in the summer, you don't really have the demands you had, you have good reliability in your other units. Those units that have to be there for capacity requirements can truly not run; hard to collect your money in LMP if you can't run.

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

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

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

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

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

Thank you very much.

MS. COCHRANE: Thank you, Gary.

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

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

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

Our next panelist is George Owens with Downes Associates.

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

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

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

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

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

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

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

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

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

When he looked at them, he immediately knew that he had the answer. If everyone has read the book, you'll know what the answer is.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Because of the debate that's going on across the street on the Energy Bill right now, we all know that energy is in the top priority, and with the cost of energy and fuels, there's going to be a drive, obviously, back to native-born fuel services, and that's going to drive us back to coal.

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

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

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

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

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

That impact on the consumer, as you know by a paper that I submitted for the last conference on this subject matter -- and I resubmitted it with some updates -- pointed out that if you take a $4 billion expenditure and give a great rate of return to the transmission companies and you give it the normal time for payback, you can pay for it in tenths of a percent per kilowatt hour to every ratepayer in PJM.

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

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

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

Before it could come to pass, it took the development of an interstate highway system, and we are going to have to build that. It's going to take the ten- to 15- to 20-year horizons to build the kind of networks we're going to have to have, because, as Gary pointed out, and Steve pointed out, our system was never built for that purpose.

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

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

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

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

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

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

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

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

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

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

I wanted to commend PJM in my comments, because I don't want anyone to think I'm being in any way critical. What Audrey said in that earlier conference I thought was extraordinarily true. She said are we looking for a strong transmission system that by its design links distant generation to load in order to address both economics and reliability and accommodate an array of generation alternatives from which load can choose. She then went on to say in many ways the Energy Policy Act of 1992 answered this question in favor of the strong superhighway to support a competitive generation industry. I don't think that could have ever been said more succinctly, and I really commend her for that.

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

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

And some would say well, George, that flies in the face of a competitive market. Quite the contrary. It's the basis of a competitive market. The better the highway system we have, the better the competition will be and we'll finally achieve what we all enjoy today under the banners of Wal-Mart, Target and some of the others.

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

MR. OWENS: Please.

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

Thank you.

MS. COCHRANE: Thank you all for your comments.

Just as a procedural matter, I'm going to ask that the transcript be put into ER05-644, which is the proceeding you alluded to, just to be on the safe side.

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

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

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

I think once they know that there is going to be a demand curve and people who do the economics, yes, they're going to have one price, you know, four years out, so they have one through four years of price, but they're going to have a way to model what is going to be in year five, year six and year seven. They can do that with surety.

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

MS. COCHRANE: David?

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

What I'm wondering is would AEP find it acceptable to show PJM four years in advance that it's met whatever the fixed requirement is and, if it did, it would not need to participate any further in the demand curve process. If you agree with that, does PJM see any disadvantages to basically letting anybody opt out who can show four years in advance that they've met whatever the fixed requirement is.

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

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

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

MR. HERLING: Seeing as how about half a dozen transmission-related questions were punted to me this morning, I think I'm going to leave this one for Tom Welch and the next panel.

(Laughter.)

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

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

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

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

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

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

In one year when I find out, I'm not going to build that plant or I run out of money, and PJM can't keep the lights on. Yes, the market worked and they had nice bilaterals and the trading people liked that, but one year is not enough time for PJM.

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

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

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

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

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

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

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

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

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

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

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

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

So, the transcription solutions and the generation solutions can actually compete and potentially demand solutions, can compete to resolve the problem. They all have to be able to resolve that problem similarly, for them to be able to compete.

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

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

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

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

You can choose related groups of generators that may be at risk or have different parameters that suggest they're at risk. At the end of that analysis, you have to decide what to do with the results.

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

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

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

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

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

What does PJM look at? If you look at redispatch costs, what are they?

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

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

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

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

MR. SORENSON: Can I add to that?

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

MR. SORENSON: We have to do that to make sure you end up with the least-cost solution. It's very easy to see that amount of congestion.

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

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

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

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

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

Also, the concept that the Energy Policy Act of 1992 had decided on the long lines versus a distributed kind of network model.

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

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

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

We know that there is a certain amount of congestion across our transmission system that these kinds of lines would resolve. That alone may not justify the lines. We know that there is a deliverability component with the generators. We know there's a deliverability component with the load in eastern PJM. All of these pieces and perhaps more need to be taken and looked at together so that we develop a holistic solution to potentially a number of issues, rather than look at each one in a silo: look at the load deliverability issues in New Jersey and find a solution to that problem, look at the integration issues for these generators and solve that problem, look at the congestion and solve that problem when we have the opportunity potentially to put an aggregate solution, a holistic solution on the table. But, before we do that, we have to challenge our historic vision of economic planning in particular and to determine whether or not it makes sense to go beyond what we have done traditionally in support of the market.

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

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

We have historic examples that took longer than that.

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

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

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

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

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

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

But I think we have to look at all three things. We have to look at the planning process, we have to look at the siting, and we have to look at pricing as a mechanism to get needed transmission to be built.

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

(Laughter.)

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

(Laughter.)

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

(Laughter.)

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

What I was trying to say is we have a backbone power requirement that's only going to be met by baseload plants. Baseload plants cannot possibly reach the market without the help of large-scale transmission. It's a matter of a holistic approach, integration resource planning, that works so far out that it allows the market to oscillate and do its job and converge around those ultimate solutions. I don't think in the long run the addition of the kind of transmission that Mountaineer would envision or that I would even propose would negate construction of generation. I think it would incent it.

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

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

(Laughter.)

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

MR. HERLING: One thing you've got to remember, Mountaineer, as I said, is a process. There are a number of tracks we have to follow to make this come together. The business issues identifying transmission elements that are viable is going to be a challenge. Figuring out how they fit together and how much capability you derive is a challenge. These are engineering tasks that we understand fairly well and we can set people to and move forward. There are a number of business issues that have to be thought through and a lot of decisions that are going to have to be made.

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

COMMISSIONER BROWNELL: Can I make a comment?

I'd like to see as part of the fix that we I think agreed to, or certainly I agreed to this morning, on the transmission planning process, I'd like to see us begin to answer those questions. You have a number of merchant propositions that have been languishing. PJM does not appear to welcome outsiders into the process. When you say "a consortium," which we certainly encourage -- we believe public power, co-ops, and private investors, as well as IOUs could be involved. But I think the business structure itself ought to be determined by the value proposition that the investment community sees in it.

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

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

So I think for all of us, including potential consortium members, to get comfortable, we need to understand that the rules are going to be more equitable. We heard this morning that the rules for transmission are vague, unclear, the process is not anywhere near as clear as for generation. So I think, as everyone has identified at one point or another, that capacity market issues are also related to transmission issues. We'd better start expediting these kinds of decisions.

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

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

MR. HERLING: Mike Kormos, who is our vice-president of operations, is working with a team internally in PJM to essentially get out to all of the various stakeholders to try to look at where the opportunities are to resolve these problems in the short-term. Obviously we have quite a list of things already in process. We have a number of shorter-term transmission fixes which are already well underway; some have already been implemented for this summer. But we are basically out talking to stakeholders, the BPU, trying to identify what the potential opportunities are to resolve these problems, understanding that the RPM has been delayed and we do need to take some actions in the meantime. But we've dedicated a lot of resources at PJM to getting out and trying to work through these issues with the local stakeholders and identify some opportunities.

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

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

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

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

(Recess.)

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

Since this is a pretty large panel, we'd like to have time for Q&A and finish up today so that we can do some wrap-up. I'll just remind people, if you all can keep your comments, your prepared statement anyway, to like around five minutes, that would be great.

Our first panelist is Tom Welch, Market Strategy with PJM. Thank you.

MR. WELCH: Thank you very much. It's a pleasure to be here.

I want to first take a shot at actually answering John Levin's question to Steve about the relationship between transmission planning and the capacity market envisioned by RPM. Both are essential.

One way of looking at the relationship is that each process informs the other. Looking long-term helps you assess what the economic challenges and opportunities will be as the system matures. Just as the data points made available through RPM will provide the requisite certainty for project investment, those same data points will also be critical inputs to the transmission planning econometrics -- econometric modeling.

Similarly, where that long-term transmission planning process identifies transmission projects with long lead times that are likely to bring substantial benefits and are, therefore, likely to be built, those data points themselves will inform RPM. I don't see this as an either/or situation at all. I think they're important complements to one another.

As you've certainly heard today, there's no shortage of ideas about how to fix the current capacity market, and virtually every element of every proposal requires balancing a variety of interests. What RPM does, while it probably doesn't satisfy any particular interest as that particular interest would most like to have it satisfied, it does do a good job of balancing and, in particular, accommodates a number of specific items which I think are important to the market and some of the participants.

The first is bilateral contracting. Andy's already covered a great deal of this, so I'll be quite brief. Obviously, bilateral contracting is an important tool in the market, but it's not actually the only tool.

It's not an end in itself. It's a way of allowing participants to hedge themselves from their positions. So in a sense, what we envision with RPM is that some aspects that might otherwise be done in bilateral markets would now be accomplished through RPM, but there are a whole set of additional kinds of bilateral contracting that would be made available.

Frankly, the greater forward price predictability that RPM is likely to stimulate or is likely to create -- we think likely will stimulate bilateral contracting. You've already heard today that the current market has the risk parameter so broadly set that there's actually very little bilateral contracting for any point of time. We think both buyers and sellers in the bilateral market will have an interest in hedging the uncertainties that remain under RPM, buyers may be uncertain about load and prices beyond the auction horizon, sellers might want to achieve greater revenue predictability and stability.

The point here again is not that the RPM will produce the greatest volume of bilateral contracts, but there's certainly no reason to believe that RPM is going to constrain bilateral contracting to levels that are unacceptable for the market and, indeed, will create a whole new set of opportunities for bilateral contracts because of the increased certainty it provides.

A second element is the relationship between this and various formulations of LSE activities. Here I don't think RPM is going to interfere with any of the load-serving entity structures or, indeed, any of the forms of regulation because it doesn't really change structurally what those entities are doing. I think it's an input to what they would be selling, but it doesn't deprive them to any great extent of the products they're selling.

Indeed, by providing greater information about future prices and supply LSEs in the competitive market may be able to offer longer-term products and stimulate competitive activities. We see this as a plus. LSEs, under traditional regulation, will be able to evaluate their procurement more effectively because the future costs of supply will be more transparent. So we see this as a positive element for LSEs.

Provider of last resort has a few dimensions. One I want to touch on briefly. There was a description a couple of times this morning that somehow PJM becomes a provider of last resort. I don't think that's true in any sense. PJM runs an auction today; it would run an auction under RPM. What PJM would do with appropriate consultation is set the slope and placement of the demand curve, the bid set, the price; the load pays the price, either in their bilaterals or to the extent they're deficient in the auction price. So PJM doesn't become a POLR.

Another dimension is, provider of last resort service cannot do what RPM is intending to do, they're not close substitutes. For one thing, provider of last resort typically only has a portion of the market, so it's not as broad as RPM needs to be. On the other hand, RPM isn't a substitute for POLR because it doesn't provide the full range of products, it's not a retail product.

So while I think they can and do work well together, they are really just different kinds of products. They attempt to achieve different things. There may be some fuller impact on supply. But it's not the kind of long-term persistent market-wide pricing we think is essential for the market as a whole.

Next, with respect to self-supply, again, RPM permits load-serving entities to self-supply their capacity obligations. In a sense, it functions very much like a bilateral. If you cover your obligation through self-supply or through bilateral contract, you're only exposed for the difference between what you expected to have as load and what you actually had as load, and you're paying the auction price for the difference. I think it's very compatible with the self-supply approach. RPM would provide important price information to LSEs who are considering self-supply and, indeed, for state commissions to evaluate whether some option which an integrated utility presents to them makes sense to them in terms of price.

We, PJM, are evaluating various ways to integrate the activities of LSEs who are under integrated resource plans into RPM, but I'll say at this point it's certainly not obvious that a complete carve-out for a vertically-integrated utility is going to be the most efficient or effective way to address the system as a whole or even for that utility's territory. I think we need to be able to understand and figure out how to integrate it successfully. I don't think a complete carve-out really makes sense.

Finally, the last item on demand response, as with bilaterals, RPM would change the opportunities for demand response. That's not the same thing as saying they'd be reduced or of inferior quality. I think one thing we've heard from quite a number of demand response entrepreneurs is that the forward signal is the one thing missing right now from their ability to put together a successful business plan. RPM specifically incorporates the ability of demand to participate in the market and actually capture an additional piece of the market that they bring. From that standpoint, I think it's a plus.

It is true that RPM in any successful capacity model will have the effect to some extent of reducing price volatility that might dampen the market for some form of demand products. It's going to create a new set of business opportunities by again providing revenue opportunities that require longer gestation and development.

In conclusion, I think perfect harmony in RPM among the various interests and participants, is very unlikely, simply because there's a wide variety of economic interests at stake.

Greater efficiency and predictable reliability is not going to affect all equally, and really requires a commitment to the long-term health of the system and a long-term view of customer costs.

While PJM is committed to continuing to work with state commissions and this Commission and market participants on all of these issues, it does seem to us that the RPM construct is sufficiently developed and understood by the parties at this point, in part through this Conference, to warrant formal consideration by FERC on a fairly near-term basis.

I think further delay is unlikely to raise additional issues that produce new insight, but would risk repeated episodes of the shortages we've seen, that could only be addressed through less efficient or more expensive solutions. Thank you.

MS. COCHRANE: Thank you for your comments, Tom. Our next panelist is Ben Hobbs from Johns Hopkins University.

MR. HOBBS: Thank you very much for inviting me to talk this afternoon. I'm going to be telling you a little bit about an analysis that we at Johns Hopkins performed for PJM, a simulation analysis of the performance of the RPM construct and alternative demand curves.

I have to preface things and say that everything I say here, all the opinions, are mine, and so are all the mistakes. They don't necessarily represent the opinion of PJM.

I think you have a set of overheads in front of you. I'm just going to skip lightly and highlight some major points, and, I hope, keep within my five to seven minutes.

On the second page, I show just a couple of examples of different demand curves. The one on the right represents the situation now where the deficiency payment represents the maximum that a load-serving entity would be willing to pay.

MS. COCHRANE: Hold on just a second.

MR. HOBBS: I apologize to those in the audience that I got off the red-eye this morning and didn't make enough copies. There are some copies sitting on the table in the back.

But it looks something like this.

MS. COCHRANE: Got it. Thank you.

MR. HOBBS: Slide 2 shows a couple of different demand curves in the abstract. Basically, the situation that PJM is now in, is on the right, with a vertical demand curve.

What's being proposed is putting some slope into it, just like in New England and New York, as you see on the left.

My hypothesis, which we tried to test for this model, is that adding slope to the curve would lower the variation in revenues that generators receive, and if you believe that generators are more likely to invest when there's less risk or they prefer less risk, that, in turn, will that or will that not result in more investment and what will happen to consumer costs?

The hypothesis is that the cost of capital is lower, then, ultimately, the cost to consumers will be lower, and that's what we tried to simulate here.

Going to the third overhead, it just shows the questions we tried to address, how the different curves affect the stability of the market, the ability to meet reserve requirements, and what are the costs to consumers?

This is really important: how robust those conclusions are to different assumptions. I cannot get into the head of generators to know what their degree of risk aversion is, or how they forecast energy prices or ICAP prices or anything else.

My whole philosophy was to have as simple a model as possible, that captures the main features we're trying to get -- risk aversion, forecasting, prices, different streams of revenue from energy and ancillary services -- then look at different curves over a whole range of possibilities, and say, are there certain curves that consistently do better than others?

There's no single set of assumptions that are right. This is not a predictive model; rather, this is a model to show what the implications of different assumptions about generator behavior are.

It does turn out that there are some robust conclusions. In a nutshell, the conclusion is, if you go from a vertical demand curve to something with a slope, you do lower risk to generators, you do increase entry, and you do wind up lowering costs to consumers.

The degree to which that happens, depends on the particular assumptions, but, under no set of assumptions that I tested, did the vertical demand curve do better, and, in very many of the cases, it did a lot worse, as we'll see in just a minute, since that's about all I have left.

(Laughter.)

MR. HOBBS: Slide No. 4 lists a variety of assumptions, and I was told there was an assumption that's not on this list that I should follow up on this afternoon.

The first assumption is that generators forecast profits, based on experience, and that they don't like risks. The more risk there is, the lower the forecast profits are, and the less entry you'll get.

I also considered random shocks to the system, whether changes in economic growth and load growth, how that affects energy and ancillary service revenues.

Another assumption is, I'm simulating a market clearing price-type system, rather than a pay-as-bid system. I sit on the California Market Surveillance Committee, and we've made quite clear, our preference for a market clearing type mechanism for efficiency reasons and because, if you have a pay-as-bid system, people, once they can guess where the market clearing price is, that's where they'll bid. So you're not going to get much difference, anyway.

I didn't think there was any purpose to looking at a pay-as-bid system. I looked only at a system where everybody gets the market clearing price for capacity, and, in part, that's because I feel it's very important that all generators get capacity payments, because all generators have options for increasing their availability when you need it, increasing the amount of capacity.

You don't want to be in a situation where, let's say, you have a $30 per kilowatt price for capacity for just new generation. So you're paying a lot for new turbines, and at the same time, there's some other generator that's retiring, that wouldn't retire if they got $10. You want everybody facing the same cost, so that everybody basically equates the marginal cost of providing capacity.

Skipping very quickly then to the next slides, 5 gives an overview of the model. If you're interested, there's an IEEE paper that's just been published, that describes the guts of the model. I can answer questions about that.

It's what's called a representative agent's dynamic simulation model. It proceeds year-by-year. Generators in a particular year look at prices and say, hey, should I build something or not?

Slide 6 shows five curves I considered. One is the vertical one, and four are various flavors of horizontal curves shifted to the right, with different slopes.

The story that I'm going to tell today in Slide No. 7, just basically contrasts the vertical curve, with Curve No. 4. The important thing to bring away from here, is that this is the sort of story you see.

The chart on the upper right shows what happens to capacity revenues. With a vertical demand curve, you get sort of a bipolar type behavior where prices are high or low -- bang, bang -- whereas a sloped curve gives you more stable revenues.

That translates into a willingness to invest at a lower return on equity, and the bottom curve on page 7 shows -- this is a sample time series. The bold line shows the reserve margins we got with the simulation of this slope curve, versus the thin line, which shows that, with the vertical curve, you're getting more investment, you're getting a more reliable system.

In terms of consumer costs, Bullet No. 3, this is just an example of numbers. The particular numbers depend on the assumptions, but in almost every case, the vertical demand curve gives you higher consumer costs.

What's the metric here? This is the sum of capacity costs and scarcity revenues when you're short of capacity, and so prices in the energy and ancillary services markets, are going above marginal costs.

Because the vertical demand construct gives you less capacity, on average, you're getting more shortages, and you're getting a higher average ICAP price.

As a result, in these particular simulations, the cost for consumers was roughly 30 percent higher -- excuse me, 40 percent higher, at $99 higher for the vertical curve, than it was for the sloped curve in this particular instance.

And that 50-percent or 40-percent difference, depends on the assumptions that you make, and I wouldn't ascribe any particular significance to 40 percent. It's just that you almost always see a positive difference. That's the important result.

The next slide shows some detailed results, which I would be glad to tell you about, returns on equity, costs to consumers, and that sort of thing, but I'll just skip the last substantive slide, which is No. 9.

The reason I like the sloped demand curve, is that it logically reflects the reality of capacity value. The value of capacity never goes to zero. It does decrease, but it never goes to zero.

It's worth having more than the target value for both mitigation and market power reasons, and because you then have greater insurance against extreme contingencies of weather or generator outage.

The result of the simulation was that, compared to vertical demand, the slope of the curves lowered risk to generators and the result was ultimately lower costs to consumers, because of lower cost of capital. Thank you.

MS. COCHRANE: Thank you very much.

The next panelist is Reem Fahey with Edison Mission Energy.

MR. FAHEY: Thank you. My name is Reem Fahey, I'm the Regional Vice-President of Market Policy for Edison Mission Energy. It's a pleasure to be here. Thank you for inviting me.

Edison Mission Energy owns or controls approximately 47,500 megawatts of coal-fired baseload units in PJM. Such units provide energy capacity, ancillary services, and support the overall reliability of the PJM system. I would like to focus my remarks today on two principle market design features that should be a component of any contemplated PJM capacity market construct.

The first critical design feature should be the inclusion of the demand curve. The principal benefit of the demand curve is that it allows for a variable reserve requirement that will provide a more robust incentive for generation investment. The demand curve recognizes the value of additional resources above the minimum reserve requirements and provide benefits to both suppliers and to load. The suppliers benefit from a more stable, predictable revenue stream coming from the value of excess reserves. On the other hand, load benefits from increased reliability and reduced exposure to price spikes in both the capacity and energy markets. The design of the curve can also reduce suppliers' potential to exercise market power. It reduces the excess revenues that may result when the shortages are created by withholding capacity. This is the same issue that Joe Bowring talked about this morning.

If reserves fall below the thresholds of the industry standard, which is loss of load probability of one day in 10 years, the pricing factor will increase to encourage generation investment to resolve the shortage. When the threshold is reached, the pricing factor will drop off slowly to recognize the value of higher generation reserve levels. This leads to stable ICAP revenue, which will reduce the risk and cost of financing investments of new generation capacity and, thus, reduce the cost of electricity to consumers in the long term.

A major market design flaw in the current PJM capacity market is the use of the vertical demand curve. The vertical demand curve sets the capacity obligation based on a single value. The consequence is that prices can be very low when a small supply excess exists and can suddenly jump very high with a modest downward change in the supply availability. The high volatile prices produced by the current PJM capacity markets discourage the development of new generation and, more importantly for EME, undermine the reliability benefits of existing generation. This type of pricing behavior tends to convey contradictory investment signals and leads to boom/bust cycles of generation developments.

From a policy perspective, EME believes the inclusion of the demand curve in the capacity market has already been vetted and carefully considered by FERC for both the New York ISO and the New England markets. FERC's order regarding the New York ISO demand curve has been affirmed on appeal, so FERC's authority to adopt such an element of the capacity market has already been upheld.

A second principal design feature of a properly-structured capacity market is the establishment of a forward capacity obligation for all load-serving entities. A forward capacity obligation sends a long-term price signal that should provide the market with a greater opportunity to determine the most cost-effective solution, whether it's generation, transmission, or demand side, in order to maintain the reliability of the system.

EME believes that a minimum of a four-year forward commitment is necessary to allow new generation to enter the market well in advance of when the capacity is actually needed for system reliability. It also allows existing generators to make informed decisions about incremental upgrades to the units and also in regard to unit retirements. Advanced capacity sales by generators may improve creditworthiness of merchant generation owners, making it less costly and easier to finance planned expansion and construction of new plants.

In addition, a four-year forward commitment benefits load-serving entities as well, because it facilitates a more robust and cost-effective transmission planning process and, more importantly, it mitigates the need to obtain reliability must-run contracts.

I would like to conclude by commending the thoughtful and complete job the PJM staff has done in developing and improving with unprecedented stakeholder input to the current RPM proposal. Prior history makes it abundantly clear, however, that the stakeholder process has run its course. Further debate at that level will not resolve any of the issues that remain. These issues require the Commission's process to address the economic considerations in light of the long-term reliability concerns. Now is the time to file the RPM capacity market proposal with FERC so it can be implemented by the summer of 2006.

Thank you again for the opportunity to speak, and I look to further debate the issues during the Q&A session. Thanks.

MS. COCHRANE: Thank you.

Our next panelist is Jonathan Wallach on behalf of the Maryland Peoples' Council.

MR. WALLACH: Thank you. My name is Jonathan Wallach, Vice-President of Resource Insight and Economic Consulting Firm based in Arlington, Massachusetts. I appear today on behalf of the Maryland Office of Peoples' Counsel, one of several supporters of the EITCC construct.

I want to first discuss the issue of the slope demand curve and explain why it is that the EITCC construct does not rely on an administratively determined curve to clear its capacity auctions. Demand curve proponents believe we have a problem with price volatility in our current capacity market. They claim that prices -- as we've just heard from Reem; don't take it personally.

(Laughter.)

MR. WALLACH: They claim that prices jump between high and low extremes, clearing at the capacity deficiency rate when the system's short and at near zero levels when the system's long and that this extreme price volatility exacerbates investor risk and stifles rational investment in new capacity. Demand curves are seen as the solution, stabilizing clearing prices and reducing the financial risk to new entry.

The problem with this argument is that it doesn't jibe with the experience in PJM. Prices in the multi-monthly auctions in the last three years have averaged between $20 and $40 a megawatt-day, not zero even though the system has been long during this period.

Moreover, neither capacity price volatility nor excess conditions appear to have been a barrier to investment. Over 15,000 megawatts of new capacity have been added to the system in the last five years; an additional 15,000 megawatts for new projects are queued up for interconnection over the next five years.

One reason for investors continued confidence is the fact that there's a vibrant bilateral market in PJM that allows parties to efficiently allocate price and other risks. In fact, over the last few years, more than 95 percent of PJM's capacity obligation has been met with bilateral transactions.

There is no question that reducing investor risk is a laudable goal, since less risk means lower financing costs and perhaps lower capacity costs to consumers. The RPM demand curves, however, are not the way to get there since they lead to short- and long-term inefficiencies. In the short-term, while the system is long, demand curve will procure excess supply at prices that exceed the marginal value of that excess capacity. In other words, this excess capacity will be paid more than its worth to stay on the system when it should either be sold into higher-value markets outside PJM or shut down. The increased costs to consumers from these short-term inefficiencies could easily exceed a billion dollars per year.

Over the long term, the RPM demand curves apparently expose investors to excessive price risk. The modeling done by Ben at Johns Hopkins we've just heard about indicates that investors under RPM will require a 20 percent return on equity or 800 basis points more than the ROE that PJM believes is adequate today to induce investment in new peaking capacity.

The bottom line is that demand curves are the wrong solution to a non-existent problem. Implementation of demand curve under RPM will likely lead to inefficient outcomes and substantial economic harm to consumers. In contrast, the EITCC construct efficiently minimizes and allocates risk and promotes general resource adequacy by facilitating voluntary long-term bilateral transactions.

As this Commission has heard from the investment community, including this morning from Brian Chin, such contracts mitigate the risk and reduce the cost of investment in new generation. Frankly, if new intervention is deemed necessary to maintain resource adequacy, the solution is not reliance on inefficient demand curve but a construct whereby PJM directly procures new capacity on behalf of load. This is similar to the EITCC mechanism for addressing deliverability issues in small local areas.

Switching gears, let me just touch briefly on the RPM proposal to use a centralized forward procurement process and the impact of that proposal on default service customers in Maryland. Under the RPM construct, PJM will procure capacity on behalf of all load in PJM to meet system capacity requirements four years in the future. This centralized procurement not only establishes a four-year forward price for capacity, but also effectively creates a four-year forward obligation on load-serving entities to purchase capacity at the four-year forward price.

This four-year forward obligation is incompatible with the provision of retail standard offer service in the State of Maryland. Maryland utilities that provide standard offer service would not be able to hedge price risks associated with this forward obligation, since they are effectively precluded by statute and regulation from procuring capacity more than three years in advance of the delivery year. So instead, SOS customers will be fully and inappropriately exposed to capacity price risks as a flow-through to SOS prices.

That completes my comments. I should mention that I have submitted a prepared statement. There should be some copies in the back and I will provide an electronic version after this conference.

MS. COCHRANE: Thank you very much.

Our next panelist is John Orr with Reliant Energy.

MR. ORR: Good afternoon. Thanks for letting me come speak with you today about capacity markets, I guess, in general focused on the RPM and competing proposals that we've seen out of, I guess I'll call them, the ODEC and friends as well as the PPL proposal here.

I'd like to start off a little bit about Reliant. Similar to what I think you heard Mr. Sorenson say on the last panel about his company, Reliant is somewhat unique and I want to be sure you have this proper perspective as I speak to you.

And that is, while I think we're viewed as a large generator in PJM -- which we are -- we are also a significant retail player in PJM and the New Jersey markets, as well as in Maryland. Nation-wide, I also serve more than a million customers in the State of Texas without any generation capacity to my name down there.

As a result, I'm concerned not with generators getting paid for investment -- not that that's not important -- or having a site in this market. What I'm looking forward to is the balanced solution that achieves the goal that resource adequacy is out to fulfill.

That transitions me into what I want to really make sure we're all clear about here. What we're talking about when we talk about resource adequacy is a long-term planning reserve. That means having iron on the ground in the future in the form of generation. Not the delivery capability that transmission wires gives you, but in the form of generation that will keep people's lights on in the future. And in the future is important, I think here.

In light of those concepts, I'm going to leave you really with five principles that I think any of these plans that are thrown in front of you you should apply as a test for these. I think you'll see how they fit together.

First, you've heard this from some other speakers this morning and this afternoon: is the design sufficiently forward-looking to get the iron on the ground in the future, yes or no. The reason this is important is because there's long lead times for generation construction and if you do not allow new entrants to compete, you will have market power issues in certain locales.

Second, the second test I would apply does the proposal eliminate barriers to entry? Does it let generation be considered, transmission be considered, demand response be considered? The reason this is important is because it's the same thing. It's related to that last concept of mitigating market power. You want enough people in enough different alternatives to be there and be available to you so that you don't have to impose mitigation and price caps and you can move more towards market-based solutions rather than administrative ones.

The third element that I would say you should apply as a test is is the design enforceable in such a way that there are no free riders? What that means is that no LSE or person serving load in this region or wherever the construct applies is able to essentially count on their neighbor to go procure something so that their lights stay on in the future.

What I would tell you here is that until you have targeted load shedding capability in this realm that we live with RTOs in control of running the markets. There's probably no better person than the RTO itself to be in this role of we'll call it facilitator of procurement, something Tom kind of touched on here and I think earlier commenters for PJM touched on. They have to perform this role to make sure there are no free riders. Once we get the targeted load shedding ability, then we can let LSEs gamble on whether they have enough in the future or not, because we'll turn them off if they haven't met their requirements.

The fourth test I would apply is does the model accommodate retail competition? Now I think we've just heard Mr. Wallach make some comments around SOS. But what I'm talking about here is does it allow for retail switching in the states, because many of the states in PJM have this.

Does it allow people to switch?

One of the key features of RPM, for example, that highlights this is that load pays in the prompt year or the delivery year based according to how much load they serve. They're not being billed today for stuff they're gonna serve four years from now. This gives them a price signal so they can go do deals into the future and what they can do is essentially hedge themselves around that using this market.

And here's another important point related to this: no matter how we do this and who draws an IRM or the like, we're gonna have forecast errors. So when anybody comes to you and says well I can't hedge this because I don't really know what I'm gonna have, we've got that problem today on a grand scale. Every utility faces this every day. PJM faces it every day when they decide how much to commit in their unit commitment process day-ahead. So don't be -- what I would implore you is don't be deterred by that argument. What you need to have is make sure the program in front of you accommodates retail access.

The last thing -- and this is really important, too, and it kind of goes back to that first theme I said, which is this is about having iron on the ground for the future -- is that whatever is offered into this needs to be real, it needs to be asset backed and deliverable.

There's a lot of talk about LD contracts and do they count and the like. What I would say to you is somewhere behind the LD contract there'd better be a generator, because all the financial penalties in the world will not keep the lights on for somebody when you have a problem or when you're run short.

When I apply these tests -- and I'm gonna wrap up here -- when I apply these tests to the proposals in front of us it's very clear to me, especially in light of the fact that the forward-looking element is the linchpin of what a good proposal has, I look at this and say RPM at least attempts to address all of these issues. It makes a pretty good attempt at it at that. I would hope that PJM does file this with FERC and we move forward with refining that design here in this forum.

The other two proposals, I believe, do not pass some of these basic tests. They're fraught with administrative remedies, potential for the exercise of market power, they don't send necessarily a forward-looking price signal. I think these are dangerous things contained within these other proposals. What I'm saying is this is the test we need to apply.

I appreciate your letting me talk to you today. Thank you.

MS. COCHRANE: Thank you, John. The next panelist is Steve Wemple with ConEdison Energy.

MR. WEMPLE: Good afternoon, Commissioners and Staff. My name is Steve Wemple and I'm the Director of Retail and Regulatory Affairs for ConEdison Energy, which is a subsidiary of ConEdison, Inc.

ConEd Energy and its affiliate, Solutions in Development, are active in the three ISO markets in the North East: New York, New England, and PJM.

Like Reliant, we're a diversified company. We own about 1500 megawatts of merchant generation. We also serve about 2,000 megawatts of retail load. We also provide load-following services and other hedging products, as financial derivatives, and we provide demand response and traditional energy services.

Last year I think I sat in the same seat. I testified before this Commission in the proceeding on compensating local generators.

While some of the issue have been raised that are the same, I think it's worth noting at least one theme that came up last year. There's a real need to come up with market solutions to compensate the resources that are needed for reliability.

That's a theme we had a year ago in February. I think it's still the same theme we're struggling with today.

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.

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.

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.

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.

Otherwise, you'll be depriving demand response of some of the revenue stream that you really need, and that it should be seeing in that ideal end state of an energy-only market.

As you're aware, PJM's current capacity market values all network resources equally throughout the PJM footprint, and relies on the transmission system to ensure deliverability.

While this approach worked reasonably when PJM was a little bit smaller, it's showing some problems in the expanded footprint. Simply put, we can't support a system where local loads rely on remote generation that's located as far as 800 miles away.

The physics of the system does not support that. You need local equipment to maintain reliability.

At the same time, the general surplus throughout the PJM region has been pushing capacity prices to historic lows, albeit, not zero in the forward markets, but 20 to 40 bucks a megawatt-day is pretty low, and has resulted, according to the PJM State of the Market Report, in under-compensating new entrants, leaving them with a third to a half of what they need over a five- to six-year period, to cover their cost of investment.

If recent investors like ConEdison Energy, have been getting only half their money for the last five years, one would expect they're not going to reinvest until they see a situation that gives them more than their average return, so they have a chance of breaking even over the long term.

There is no expectation, given the current market structure, that we're going to see that in the local areas under the current capacity construct.

PJM has recognized that some units that have said they are not covering their costs, such as the PSEG units we heard about earlier, are needed for reliability and have been offered the opportunity to seek RMR compensation.

While it's important to maintain reliability, that compensation means that demand response in the same area and other generators similarly situated, are not getting the right price signal.

In order to achieve an efficient market outcome, the PJM capacity construct must be restructured to allow demand-response and traditional generators to see that right price signal.

If units needed to maintain reliability, are given a payment of $50 a kilowatt-year to stay in service for reliability, demand response that's capable of curtailing at levels at or below that same price, should also be able to be compensated.

Putting everybody on a level playing field, assumes customers can hedge their costs, either by entering into bilateral contracts with local suppliers, or by investing in their own demand response measures.

Moving to the issue of demand response, under the RPM proposal, demand-response participants can either sell their capability to curtail load as capacity into the PJM markets, or elect to participate right before the delivery year by enrolling -- and I'm going to read the acronym because every time we come up with a new acronym, it's confusing -- interruptible load for reliability program -- there months before the program year.

Because the capacity value that the ILR program will convey, is effectively determined by the auction that happened four years forward under the RPM proposal, demand-response participants can use the results of that four-year forward auction to plan their demand-response strategies and determine what measures are economic to invest in.

For example, under the RPM program, when a customer elects to participate in a given year's ILR program, they will effectively know the value, not just for the upcoming planning year, but for the following three years. All of those auctions were predetermined.

This forward valuation can help customers and demand-response providers determine the installations and/or equipment upgrades that are cost-effective and that should be pursued.

For example, existing projects requiring less than ten months of lead time, will basically be able to bank on a known revenue stream for the first four years of their operation.

RPM timeline also allows customers with existing and planned demand response, multiple ways to optimize their capacity value, in addition to selling into the four-year forward auction.

If they are not cleared of that auction, the ILR gives them a floor price, knowing that they won't do any worse than the price in that forward auction, so they can look to improve upon that by offering their capability into subsequent incremental auctions.

Although ILR participants do not directly interact with the base residual auction, the RPM design ensures that demand response will impact the clearing price in the base residual auction and reduce capacity prices for all consumers.

This is because PJM's plan assumes a quantity of ILR will participate in the future planning year and clears the initial base residual auction as if that amount of ILR had actually offered to sell and was cleared in the auction.

For example, if 5,000 megawatts of demand response is assumed to participate in a future year's ILR, PJM will clear the auction as if that capacity was there and had been bid in, and did clear.

So, we've moved down the demand curve and you will have the societal benefits of that demand response participation. In contrast, the EITCC proposal, in my opinion, is not likely to attract as much demand response, especially in zones and local load pockets, and, therefore, is like to result in un-hedgeable costs, because it relies on RMR payments and transmission solutions to solve reliability problems that are more granular than the two relatively broad locational capacity markets that are envisioned for the Eastern MAC and Southwestern MAC regions.

This coarse approach to local capacity markets, ensure that if the Eastern MAC region fails to generate a price high enough to attract the resources needed to support the reliability in, for example, the PSEG Zone, then an out-of-market payment will be made to specific PSEG suppliers to ensure reliability until a transmission solution is built. That sounds like where we are today.

That, in turn, will impose un-hedgeable costs on consumers, and fail to value the demand-response measures that could be cost-effective, compared to that RMR payment or even compared to the transmission solution that will be built to solve the PSEG problem in that example.

In conclusion, I'd like to reiterate that RMR payments are a non-market solution, by definition. They prevent other resources, including demand-response measures, from realizing the full value of the reliability service they can provide.

Both the existing PJM capacity market and the proposed EITCC construct, rely on RMR payments to maintain local reliability. They will depress the price that demand-response measures would otherwise receive under a true market clearing solution, and, in my opinion, lead to less demand-response participation than you would see in an optimal solution.

Furthermore, the customer impact under a market solution, is significantly different than under an RMR solution. Under a market solution, as a retailer, I can hedge my costs; under a non-market solution, those un-hedgeable and unpredictable costs are a major risk for consumers trying to plan a budget.

To touch on two issues that were brought up earlier today, one that was a little understated is the operational and reliability metrics included in the RPM proposal. Currently, PJM does not have any way of compensating units providing 10 minute non-spinning or 30 minute reserves, even though it relies on those ancillary services to maintain reliability. RPM seeks to solve that absence of a market for that reliability service by procuring it effectively on a forward basis. This is an important element to complement PJM's markets and ensure the right components that provide reliability are being given a price for the service that they're providing.

The other issue that was brought up today is the concept of looking at congestion. If the eastern MAC clears at a high price uniformly throughout all the zones into New Jersey, the supposition is that the reliability problem was in eastern MAC. Just because you have congestion in certain zones doesn't mean the reliability problems align with those, say, in congestion zones. You could very well have a lot of surplus capacity in eastern MAC, but outside of New Jersey that just happens to be high cost because of the high cost of natural gas and distillate oil and have an abundance of supply from a reliability perspective. In the tight pockets of New Jersey, for example, you might generate the same price and be a lot tighter on supply and have a reliability problem that you would not see just from looking at the gross aggregate LMPs.

That concludes my comments. Thank you very much.

MS. COCHRANE: Thank you, Steve.

The next panelist is Stephen Fernands with Customized Energy Solutions.

MR. FERNANDS: Thank you. I want to express my appreciation for being invited here. I feel like this sort of brings me full circle. I started my first meeting representing a client -- back then it was New Energy Ventures. It was a PA, Pennsylvania Commission hearing on capacity markets. I was fresh out, starting -- putting my shingle out and starting Customized Energy Solutions. Commissioner Brownell was there and we said boy, we need a capacity market. At that point in PJM, everything was bilateral. We had people saying at that point why do you need a market, you know, we just all do this bilaterally, everyone agrees here, you don't need any type of transparent market. And we set up the daily market and the forward markets that we have today. Those markets have evolved greatly since then, but the foundation was laid back then.

So I appreciate the opportunity now to come and talk about that. I've been involved in pretty much every capacity iteration since then at PJM from some of the early ones with many of the same people here.

The fundamental question is why do we need capacity markets. There are two reasons. The primary reason is we don't trust that the energy markets will give us the level of reliability we need. Why don't we believe that?

Number one, a lack of demand side response. We don't have customers that can respond to prices and produce their consumption when prices are high. The second reason is we don't have adequate transmission systems to deliver all the electricity to customers; therefore, we say we need locational markets.

It's because of those two reasons that we now have probably one of the most convoluted central procurement non-market based mechanisms ever proposed in the history of PJM, and we're talking about it like oh, yeah, this sounds like something, you know, we can talk about. It's antithetical to a competitive market where you have the ISO going out on behalf of load and procuring the entire capacity responsibility. It will kill bilateral markets, as mentioned by TPL, and I thoroughly agree with them.

So how do we get to the problem? One of the things we address is the root. So you say okay the root's not enough demand side response and not enough transmission. Then, RPM, does that solve that root problem?

For those of you who are trying to follow on paper, mine's the little one with the lightbulb in the corner.

There are four major reasons why RPM is anathema to demand side response. I have been active in PJM's demand side response program since it started. Our company chair, Rick Mancini, chairs the price responsive load working group in New York. We've been very active on demand side response issues in each of the markets we've participated in.

RPM in particular does not work for demand side response resources, at least not the ones I represent and the ones that are currently participating in PJM's markets that I work with. The first area is forward procurement. Right now you're asking demand side response to commit a month or two actually prior to June 1st that they will reduce their peak consumption during the summer period. Now you're asking them to forecast what their peak's going to be three years from now and how much they're going to be able to reduce that peak in the fourth year. I believe very few customers, even the most organized, have great business plans and know where they're going, are able to accurately forecast those types of uncertainties in the market.

According to a study done by Neenan and Associates in response to an earlier iteration of RAM, they -- to quote them -- an objective of the RAM Group was to not discriminate among resource types. The results of the demand resource providers surveyed clearly indicate that many current demand resource providers would not be able to participate in a CRAM with a three-year planning horizon. So we're now looking at four. That study looked at six months to three years and found the lowest response rates and lowest participation rates in the three year and the highest participation rates in the shorter term.

Next is the locational component. There's a lot that's been made of well we have these locational problems, we need to address them. And I completely agree with that. We do have problems right now locationally, they do need to be resolved. However, we're looking to try to trick generators into siting there and then building the transmission which is going to stop the premiums in those areas and get a bunch of transmission owners that have invested in the wrong place because the premiums that they were expecting vanish as soon as the transmission upgrades go in.

If we see a transitory problem that's going to be resolved by transmission, it's much more honest to say let's go, let's offer those customers RMR contracts while we're building the transmission instead of trying to say we need a market solution here for a very short-term transitional problem. Same with demand side response. If you're trying to trick demand side response, it won't work out. I hope it won't work with generation owners either.

The third thing is there's a disconnect with the current expiration dates. We heard earlier today that there will be some kind of demand side response program. I heard Andy say it's going to be a continuation of the demand side response program and made permanent. I wish that was actually true and we can stop all these debates that we're having in the demand side response working group. Currently it's set to expire in 2007. There are a group of people, myself included, trying to get it to expand. Right now -- I counted 13 of the 21 people mentioned demand side respond today. Over 50 times it's been referenced today.

Last year the incentive components for demand side response were about $200,000, so that works out to less than $4,000 per mention today of demand side response. It's something that gets a lot of talk. That's not per megawatt, that's like $4,000 for the entire PJM the entire year payment. It gets a lot of lip but it actually doesn't get a lot of dollars and doesn't get people saying oh wow, you know, demand side response, that's costing us billions of dollars in capacity, we really need to fix that. We really need to spend the money to make sure that we have the infrastructure in place. We really need to spend the money. So we have adequate demand side response instead of just saying hey, yeah, it's important and then going on and phasing out the various demand side response programs.

The fourth one is improper active load management penalty. The Commission will hopefully be seeing something filed by PJM later on this year.

Right now, if one of my clients is interested in demand-side response, and being in ALM this summer, they said, that's our risk. If you don't perform, per megawatt, it's a $6400 per megawatt penalty.

What's our revenue? Right now, it's about $10 per megawatt-day. It's about $3200.

So you're telling me, if I mess up once, I have to pay two times the amount that I get paid for the whole year. Yes, that's about it.

And how many times do I have to perform during the Summer? Up to ten. Could you imagine a generator operating in those types environments? It's just ludicrous.

So we're trying to come up with penalties that are market-based. The penalty currently pushes demand-side response out of the capacity market.

So, what does PJM need for a long-term solution? Number one, it needs a goal-driven demand-side response market, so you don't get somewhere just by saying, that's nice; I'd love to go to Aruba, but if I don't book a plane, if I don't plan for it, I'm not going to go there.

If we think we need so much demand-side response to actually fix the market, let's plan for it. Let's say, okay, this is the amount we need to alleviate market power; this is the amount we need to move to a more market-based system, and head there, find out what are the incentives and what are the things we need to do to get there.

The second one is a permanent seat for demand-side response in the market. Right now, we've been going with programs for so many years, there have been proposals put on the table to do away with any type of incentive payments and decrease the amount of revenues that are given to demand-side response by some of the other panelists that have been on here today, instead of saying we need to be increasing demand-side response, not decreasing.

It needs to be permanent; it needs to reflect the benefits of demand-side responsiveness.

The third thing I have here is, if loads paying hundreds of millions of dollars in capacity payments for not having proper demand-side response, what's the value of demand-side response, if it is able to fix that problem, and how do we compensate demand-side response adequately for creating a more functioning wholesale market?

So, where will DSR get you, that the capacity market won't, especially the RPM market won't? First, DSR will result in a more efficient use of generation resources.

P.S., I'd just mention that we have two generators that never ran. It's horrible that we lost those generators, and that they retired them.

Eventually, resources retire, and resources that are unutilized, retire. If they're not using them, the idea of having those resources around to provide ten hours a year of service, demand-side response can do that. We don't need to be paying generators to stand around and do nothing.

The next thing the demand-side response will do that this capacity market will not do, is that there will be rational pricing during periods of scarcity, with the value of load-curtailing setting the price, instead of generation market power. It's probably one of the most important things that demand-side response can provide.

It can provide what is the value of energy during times of scarcity. Right now, we don't know. Right now, we have lots of artificial price caps and other things that interfere with that.

We need to create ways demand-side response can actively participate in the market and can set price. And they do that in the day-ahead market right now, and, I believe, if we continue to encourage that, we can even get more participation.

The third way is, there will be less need for price caps and mitigation, as demand-side response will mitigate the market power of generation owners.

Locational capacity markets go 180 degrees in the other direction. It's going to increase market power of generation owners, as you shrink the markets.

We already have a capacity market that has been characterized as having market power, endemically. If you look at the State of the Market Report, that gets better with demand-side response; it gets worse as you Balkanize the transmission system.

The fourth thing is that the demand-side response will provide a market signal for more efficient generation, including baseload units. Instead of sending a price signal for increased peaking units right now, one of the wrong signals locational capacity can send, is that you end up perpetuating a market that ends up being more and more Balkanized, instead of doing transmission solutions or demand-side response across the market.

I also wanted to mention -- and some of these have already been stated, so I won't reiterate all of them, but -- some fallacies about the existing capacity construct.

One is, prices are either at the deficiency rate, or zero. It's not true. Academically, I think there are reasons maybe why it should be, but it is not.

There's an opportunity cost generators have of participating in the day-ahead market. The opportunities, they give up by not being able to sell firm, go back into other markets.

Prices vary between $20 and $100 per megawatt-day in the monthly and forward markets. As recently as last Summer, we were very long, not as long as we are now, but we were long on capacity.

The monthly markets during the Summer were regularly clearing about $60 per megawatt-day throughout the Summer.

Fallacy Two: Demand-side response can't participate in PJM's current capacity market; you've heard that a couple of times today. They absolutely can; we do on behalf of our clients, and they're able to participate effectively in the markets.

The third one is that the daily market serves no value. Right now, less than two percent of the capacity is purchased in the day-ahead capacity market. It does serve as a clearinghouse for load-switching and also relieving short and long positions.

I believe it offers new generation that sites opportunities to sell and lowers opportunities to purchase relatively small quantities, as the market has been relatively small.

It also provides a more visible pricing note to the market on a more real-time basis, so that people can respond better.

Fallacy Four: Generators need one year of capacity revenues, four years out, to secure financing. Hopefully that's been debunked by what you've heard already.

Fallacy Five: To determine what transmission upgrades are needed, you need a four-year commitment ahead, and you can't do it probabalistically, and we have to close our eyes and say all the generators are going to stay there because I haven't gotten a letter saying they're going to not go away.

We can make forecasts before generation will retire. That can be done, especially in large sections of the PJM system.

So, in conclusion, the root cause of the capacity market is insufficient demand-side response and transmission development. It can be dealt with in a more efficient way than the RPM.

The EITCC proposal does go a long way towards improving the RPM model, by restricting the timeframe to one year. Demand-side response can participate more readily, and there are also auction mechanisms they've proposed, for those locational problems, which would also be a place for demand-side response to participate.

As well, the EITCC proposal deals very directly with the need for transmission enhancements. However, EITCC's proposal, even though we've helped and many of our clients support it, I believe it's better than RPM, but still worse than what we actually have today.

In looking to improve our transmission planning and creating a road map for increasing demand-side response, and improving the underlying reasons why we need the capacity market in the first place, is the way to go.

I want to thank you for the opportunity, again. That will conclude my remarks. Thank you.

MS. COCHRANE: Thank you, Steve. Having the dubious responsibility of being the last panelist of the day, is Mark Scott from Old Dominion Electric Cooperative. We are running behind now. I would just ask what Commissioner Brownell said at the beginning, if what's on your discussion has already been discussed, if you can just say it, as someone said before, you know, thank you very much.

MR. SCOTT: Thank you very much for the invitation to make some remarks. I'm Mark Scott. I'm here on behalf of Old Dominion.

I'm an active supporter of the EITCC proposal. I would like to leave you with three main themes here today, that I will hit, and then touch on a few of the parts of my actual remarks, my outlined remarks, that haven't been covered by other speakers, and then I will try to wrap it up.

The first thing is that there are not shades of gray in terms of comparing the alternatives. EITCC is a more market-oriented approach in terms of how individual participants manage their obligations and their risks.

RPM is an administrative solution that, in my opinion, puts PJM generally in an inappropriate role in terms of the procurement function. When I speak later about the one topic that I will expend some more detail on, on the bilateral contracts, I'll try to make that much more clear.

I've heard throughout today, people complaining about shorter horizons like one year, one month, two years, and four years has become the Holy Grail as if there's harmony if that occurs, and there's benefits of reducing the volatility if we go further out.

The question I wanted to pose is, even if we have a shorter horizon, I wanted to ask everybody throughout the day that made those statements, what keeps you from selling that product forward two or three years, today, to a willing buyer?

Unfortunately, it's going to have to be at a mutually-agreeable price. That's where we get to crux of the issue here.

We can talk about the theory of what sends the proper signal and how we properly define the right obligation. As you see, most of the folks here now are admitting that there's some local element that's necessary.

That would include that, in the market, that there would be a signal. If it's a unit that has concerns about their retirement profile, they could lock in the revenue stream, if they sold their capacity, common or local, as we saw it going to, and they can improve certainty of revenue.

But it goes past that. We're not talking about the actual sending of a price signal; we're talking about the level of the price signal.

When I get into discussions with my younger children, it's differentiating between need and want, and I think that is a core issue, which we're really wrestling with here today, and why the stakeholder process has had a hard time coming to an agreement on that particular issue.

The second main theme I would like to leave you with is, when I listened to some of the others earlier, I felt like we were being done a favor by the load community. People were damping volatility, they were reducing risks for investors, and everybody's a winner, right?

That's not happening for free; there's a price attached to it. The estimates range -- whether it's $1 billion or $5 billion a year, during the visible horizon where we can see higher costs.

There are savings that are promised, based on equilibrium model. Once we have this equilibrium, I'm not as confident at this point, in the changing and dynamic industry, of how predictive that equilibrium model is or isn't.

Maybe it's right on, but what I can see, I know, costs more, and if there's individual participants who wish to manage the risks or are concerned about the volatility, the individual participants can weigh off that risk, or leave it to people who are better capable to step in and manage it.

We don't have to have somebody to step in and do that on behalf of every market participant for 100 percent of obligation for four years forward, including all load growth. Those are fundamental differences in approach.

The third thing -- and it's the important one -- is that the bilaterals are going to have a similar role under either of the alternatives, and that market participants have comparable incentives to enter into.

I'm going to touch on just a couple of points on my outline here, and that, I will cover much quicker. As you've gathered, we're focusing on both transmission and capacity. That seems to now be a more common theme in terms of how the market looks.

Our market will operate on fungible capacity credits. The common area remains the same as the construct today, other than lengthening the obligation.

The non-local part of the local area still stays common, and then there's a subset of the local obligation where there's actual local sub-obligation. We are acknowledging that there needs to be a element of flavor of the current capacity construct, and that transmission needs to be expanded with it.

The next section in here, which I'm going to touch on very little, is the common misconceptions that I think exist, that have already been touched on by a few other people, but the reason I just wanted to reference them and why they're here, is that some of these incorrect conclusions, drive misguided actions on which construct and which alternative, and which problem we think we're solving.

You've heard that over-reliance on short capacity markets, impedes investment. Only one percent of the daily volume clears in the daily markets. Joe Bowring's Market Monitor has incredible detail of long, short, what cleared in the multi-month auction, what cleared in the monthly auctions.

If you look at that, the bulk of the market is operating on a longer horizon and a bilateral market outside of this over-reliance on an extreme low or extreme high.

Price is a function of risk and time horizon, even in periods of excess. The market's not digital. I'd be happy to go into that in more detail, if time would allow.

The other thing is, under RPM -- and I'm only going to make one other comment or two comments here, is that it might be a mistake to act like markets are bigger than what they are in terms of local area, in terms of granularity, but I think it's also an equal mistake -- and maybe you get a different error -- but to act like you can have a much smaller area and act like that's then a market.

If I'm down to a point of needing a plant on a specific bus in a specific sub-area of the DDC, drawing a boundary around it and putting in an administrative curve and I force people to buy and serve against it, acting like that's a market proxy process, at that time, I think you have to step back and ask yourself, what a competitive auction or procurement for capacity is in that area, and then handle how the pricing of that resource interacts with the balance of the market, and do it in such a way that you don't interfere and subvert the market process.

You have to step back and ask yourself that question.

The other thing I will mention on here, is that we've heard the benefits of a common time step. I will credit RPM. They are trying to achieve a common time step between transmission and generation, but I view that as a disadvantage.

It's like saying that I and one of the other participants on the panel, in total, have an average bill. It's true, in total, but, in practice, not really right on.

Some of the transmission solutions are longer lead time -- five, seven, ten years. By forcing a solution on the four-year horizon, you have more longer-solution items.

By contrast, combustion turbine projects can be done in two years. Why should anybody commit on my behalf to build a peaking facility and cost it four years out? I don't have to commit to that; I can do that to myself on a much shorter time horizon.

Why should the market force that to occur arbitrarily at the four-year point?

I guess the final point or two that I'd like to make are on this next table. It's kind of what I've laid out or compared between RPM and EITCC.

This really gets at the market versus the administrative process. Under RPM, part of how that administrative price curve is set, is based on kind of really a net revenue or cost-of-service type determination from an equilibrium model.

They do adjust it, and there is feedback. The person buying it is PJM. The pricing, which is critically important in the competitive market, is how price gets set, based on this curve.

It's not willing sellers and willing buyers. You are clearing the market, four years out, on all obligations, looking at projected load for everyone.

Assuming that every market participant needs to be fully hedged for four years out, that also is going to impact the bilateral markets, and I think the way that I'd like to respond to or address that is using Andy's earlier energy analogy about how, well, people said we're going to go to LMP and that would destroy the bilateral market, and, look, that's not the case.

I would agree that that's not the case, but that is a very different analogy, and that relationship is not the same. LMP has a lot of localized stuff. The liquidity comes through the hub, but when we went to LMP, we didn't buy everybody's, all their energy obligations, and lock in a fixed price on their behalf for four years, which is what we're doing under this item here.

Why would I ever enter into a bilateral transaction, when you've defined my price for four years out, of somebody serving load? And the way that I would answer or respond to that, to anybody, is, if you're serving load and you have an obligation to serve load, network integrated transmission service is a tariff and a pass-through.

How many people in this room actively feel they have to manage and hedge the risk and enter into a bilateral year five through ten in their nets? They don't. It's a pass-through.

Everybody has the same price; it's common. You're narrowing the size of the pie where participants can really differentiate themselves.

I think the better model is, you focus on defining the obligation that's at a common level, and a local level, then allowing the market to clear.

And the final remark I will make on that is, while we're allowing forward voluntary markets, in which willing buyers and willing sellers set prices, there is a final clearing auction that's going to clear the market two months before.

Much like today, I don't think there's any reason to believe, like today, we had one percent in the daily markets. I don't think there's any reason to believe that the volume would look that much different, going into this final clearing auction, than we have today, which is really minimal.

So, those are my main remarks. There are other items in here that I could go into with probably detail, between market and non-market, but I think the difference in that voluntary versus mandatory final clearing, is consistent with how the energy market clears today.

We don't artificially force clearing the market on an extended horizon. We're looking at organizing informal commodity markets, perishable, non-perishable, voluntary clearing markets, and the sort of voluntary clearing of the market works.

You'd have to argue with too much precedent in market activity to deny that. Thank you. Those are my remarks.

MS. COCHRANE: Thank you very much. Dave?

MR. MEAD: I heard in your presentation, you made the conclusion that the PJM RPM wouldn't work well, would be a carve-out for IOUs. I was wondering if you could sort of embellish on that? What do you see as the complication or the disadvantages, if not just IOUs, but any LSE who could come to PJM, four years in advance, and say, I've met some target level of capacity, here it is, I would like you to take all my load out of the auction? Can you sort of embellish on what those complications and disadvantages are that you see?

MR. WELCH: In a sense, RPM permits people to do that in its internal structure but not quite the exactitude that your question suggests. If I'm an LSE and I have an IRP obligation and I'm sort of self-contained, to the extent that when I get to the target year, my load is what -- I have bid in enough capacity to cover the load that I actually have, it's a wash. I am kind of out of it.

The difficulty of having an LSE just say four years ahead, when I show up with whatever load I show up with four years from now, ignore me, because I've kind of dealt within my own little way. It's hard to know how you can even talk about that person as being part of the market. There's presumably going to be some difference. There could, at least in theory, be some difference between what they bring to the market on the capacity side in the target year and what they bring to the market on the load side in the target year.

The question is what do you do with that? Do you allow them to meet some different obligation than the market as a whole, which actually creates some inefficiencies for the market as a whole, or do you sort of treat them as RPM treats them and say okay you have to meet the target obligation to the market as a whole and, to the extent you miss, you miss and you pay the RPM price.

I guess, as I said, the details of exactly how that work through are ones that we have to work on but I don't think the answer is to have people be able to say in year one when you're looking at year four, you can just ignore my existence beginning in that target year because somehow it will all work out for me.

MR. BANDERA: Just to follow-up, like the representative from AEP was sort of talking about that. I don't think he was saying that's what he wanted. It sounded like they do have a vertically-integrated structure and they would be able to identify their resources or resources that they would be bringing forward given that they don't have the sort of retail competition type situation that really poses a problem and in many ways is the reason that the structures are necessary. It just sort of seems that if they were able to make those showings under some guidelines that it would be compatible.

MR. WELCH: I thought I heard him say something slightly different actually. I heard him say that they should not be subject to the overall capacity requirements because they have one of their own. I think it's an interesting question about whether the one that he described at 15 percent compared to an 18 percent to which RPM might clear is actually apples to apples. I think they're probably not. I think the one they actually use is probably a lot more like a team if you take into account for future uncertainties and things of that nature.

So I mean I did hear him say let us determine in our little world what our standards are; as long as we meet those, you can ignore us. I don't think that addresses the problem that in fact if they're short the rest of the PJM market is going to be asked -- they're going to be drawing on capacity from the rest of the market. If they're long, they're going to be selling it into the PJM market where you would have a completely different set of rules for a particular entity. Because they were structured in a particular way, it's not obvious to me why you wouldn't just accommodate them by saying okay, you're going to have a certain amount of generation, fine, bid that in. If your predictions are correct, it's going to wash.

MR. BANDERA: You have the load curtailment opportunities. With a load structure like PJM, it would be like the one -- like being on the same distribution system. You can't cut off one without the other. But in the AEP system it would be one that would be consistent with the ability to sort of say you guys didn't come up with what you wanted to, you can't lean on the additional resources that everyone else outside of this region is procuring.

It does seem like it would be a situation --

MR. WELCH: In a sense, if you can take it outside the context of just the vertically-integrated utility, which in a sense could be looked at as just another load sitting somewhere, if you ever get to the point where you can cut off particular loads, that has interesting implications for what their obligations are. It's just not obvious to me that you'd want to say up front until that something that's both possible, politically likely to be sustainable, or available to a broader set, you'd want to leap to the conclusion that says okay because you happen to be vertically-integrated, we're going to treat you differently than the rest of the market. I guess it's not obvious to me that somehow that's the conclusion you get to.

I do agree once you get to the point of being able to shut off individual loads -- when I say "get to the point," I just don't meant technologically, I mean politically and a variety of other things. I think that does have some interesting implications for what you should be paying because in a sense you may be getting a different service than somebody else. I don't think we're there.

MR. O'NEILL: Do we have a chicken-and-egg problem here? Once you get to that position things change, but we don't know how to get to that position because you won't give people an opt out.

And the other question I have, are we saying that AEP gets to determine its own reliability criteria?

MR. WELCH: That's what I heard, the suggestion from the AEP witness. I may have misheard it, but my sense was that AEP would say I have a commitment my state commission has imposed on me and as long as I meet that one I should be subject -- to the extent I misunderstood or I misunderstood it, but I think that's what I heard him saying.

MR. O'NEILL: I don't think we allow people to set their own reliability criteria.

MS. COCHRANE: Can I say that since he's not here --

MR. O'NEILL: As a general rule, do we let people set their own reliability criteria? The reliability council, not the individual utility.

MS. COCHRANE: I think that we will have an opportunity for people to file comments after this, so maybe if we can --

MR. O'NEILL: It's a generic issue. It's not just AEP.

MS. COCHRANE: It is a generic issue and maybe if Tom can address it as more of a generic issue instead of on what --

MR. WELCH: Okay. Again, if you're trying to capture the benefits of the broad market, it seems to me just intuitively you want to have the rules as generally applicable as possible. In the question you say are we somehow preventing people from dealing with -- if they have the ability to curtail load, are we cutting off that or are we taking advantage of that? I don't think so. That's one of the reasons the demand products are being created. There are just a variety of ways of capturing the economic value or whatever you're doing at those points. I'm not sure why that follows.

MR. O'NEILL: It seems that one of the demand products, if you want to put things in categories, that people are asking for is the ability to simply opt out of the capacity market. That, to me, is a demand product. It requires you to be demand responsive.

MR. FAHEY: Tom, if I may, I believe that PJM did hear this AEP concern. In essence, the way they've proposed to deal with it is, if you believe them, procure four years forward for 15 percent, then they show up to the auction, then they show up with their generation to the auction and they self-schedule.

To the extent that the demand curve may procure more than 15 percent -- let's say it procures 16 percent or 17 percent, what PJM has done to accommodate them -- and I believe that's a change that Andy has done -- in essence they allow you to sort of do two things with an asset: you can self-schedule it to the extent that you meet your requirements but then anything above that you can actually sell it in the market so you can actually put a sell offer for the remaining amount. So I believe that this does address the AEP issue.

One other quick question on why you can just kind of carve it out and say well this is good enough. AEP is in a retail state. Who's going to serve some of the load that's going to leave the AEP system? In essence, that's what the RPM proposal does. To the extent they think they don't have the load and the retail supplier says well I'm not serving that load, PJM knows the load is out there and we're going to make sure that load gets covered. As long as they're in a retail state, that's something important that needs to be considered.

MR. MEAD: One of the concerns I thought I heard AEP mention was the variable resource requirement; going into the four year auction, they don't know exactly what their requirement is. If there could be some agreement in advance that if I'm bringing them the requirement -- if it's 15 percent or PJM thinks it ought to be 18 percent or whatever it is, if you could name that requirement and some LSE says PJM, you forecasted my load to be X, here's 115 percent of X, here it is, take my whole load out of the auction, I don't want to be subject to the variable requirement -- which may turn out to be 12 percent or 124 percent depending on what happens at the auction. Is there something wrong with that sort of option?

MR. FAHEY: In essence, a generator within the AEP system. I mean, if you look at the demand curve, the only time the demand curve procures more capacity is if the total cost of the capacity is lower. They're not procuring capacity and increasing everybody's costs, because it's sloped down. So the extent that they're procuring a little bit more capacity, the resources that AEP has they can hedge against, it could be 16 percent or 17 percent because they could self-schedule their units to say if it's 16 percent use this unit but to the extent that there is extra megawatts, then sell it in the auction. And they're completely hedged that way.

MR. O'NEILL: I'm not sure whether you're making the case for allowing them to opt out. If they're completely hedged by what they put into the auction, you can simply take them out.

MS. FAHEY: I'm not saying -- this doesn't address their issue their issue 100 percent. Their issue is, I only want to procure 15 percent.

At least the demand curve brings many other benefits. To the extent that they can opt out or, in essence, PJM has designed the auction to allow their resources, to allow them to hedge against the 15 percent, all that I'm trying to say is, PJM has tried to address their concern.

MR. O'NEILL: I realize there's a small glitch, probably in that opt-out provision, but it may be small in comparison to the lift it gets, politically.

MR. SINGH: Dick, this is nothing new. Under the demand-curve approach, you can never completely self-provide. That's something people know in New York.

MR. O'NEILL: That's the glitch, but how big of a glitch is it?

MR. FERNANDS: If I may, to be able to self-supply, I think you need to fit into the auction or submit into the auction, up to the maximum amount, wherever the demand curve intersects to zero.

If it's 135 or 132, the way you won't have to pass any additional costs on to your customers, through additional procurements, is by supply enough capacity to meet your load to the extreme of the demand curve where it intersects with zero.

That's the only way you can completely hedge and make sure there are no additional costs.

MR. O'NEILL: Is the system more reliable, if you go out that far?

MR. FERNANDS: I don't believe so.

MR. O'NEILL: So reliability really is a cliff that you fall off of at 18 percent.

MR. FERNANDS: I believe there might be efficiencies in terms of reliability.

MR. O'NEILL: If you look at the way Steve Herling develops those numbers, they come out of all kinds of scenarios where there's all kinds of assumptions.

I don't know how you can believe that there's some magic number where you fall off a cliff.

MR. WALLACH: Can I respond to that, Dick? There are decreasing returns as you go further and further out. You may not be falling off a cliff; there may be some tiny increment of reliability improvement, but the question always becomes one of what's the value of that increment?

MR. O'NEILL: I agree with you completely, and you believe it's a cliff that you fall off of. Let's say 15 percent gives you perfect reliability, and 15.5 percent basically gives you too much?

MR. WALLACH: That has been the basis for establishing --

MR. O'NEILL: And that model has so many assumptions in it, that you could drive a truck through it.

MR. WEMPLE: Dick, in addition to the point you raised, which is a good one, the amount of capacity to maintain one in ten, is not a precise science, calculated down to a tenth of a megawatt. It is a range of estimates, depending on what you're driving in your forecast assumptions.

But there are two practical considerations: If one were to, hypothetically, consider a carve-out, one is that the surplus capacity in the rest of the region that is paying for it, actually not just provides the extra reliability benefit, but also provides an energy benefit, because you have a surplus bidding into it.

So, there are some equity issues about having somebody be in one part of the PJM market, getting the benefits from the energy side and not the other.

There's a separate equity issue of a vertically-integrated entity saying, okay, even if it's 15 plus the premium, 16 or 17, now I've got some extra capacity, that, guess what, is paid for in rate base. For that to the sell into this competitive market, you could have all sorts of strange mixing and matching, if that vertically-integrated entity, with most of their assets, with all of their assets in rate base, covering some of their requirements, then had one foot in a competitive market.

MR. O'NEILL: I agree that it isn't a perfect fit, but, you know, if it helps the process, I mean, let's figure out how imperfect it is, and let's not make the perfect the enemy of the good.

All of these things, to use Mark's term, all of these numbers are administratively determined. They're not generated by any market.

You're just choosing among the administratively-determined numbers or demand curves or whatever. I realize that it raises a lot of political hackles.

We say, oh, this is administrative. Everything here is administratively determined. It's just which one you want to choose.

MS. FAHEY: If I may, you posed the question to some of the panelists about, well, what's the right level of reliability? To me, I think the best example and real-life proof of the demand curve, is what we have right now -- excess capacity, capacity prices are very low, and energy prices are very low, and the only reason why these two phenomena exist, is because we have excess capacity.

And that's really what the demand curve tries to do. It ultimately says, everyone benefits from a little bit of excess, above and beyond targeted reserve margins.

MR. SINGH: I have a quick question for Tom, just to clarify something that was said about PJM not being POLR. I think that was a good point.

But if I'm a generator and I then win in this auction that PJM facilitates, who is that contract with? Who is my counterparty?

Isn't it PJM?

MR. WELCH: I mean, there is an obligation that the generator undertakes, that if they do not fulfill it, they are penalized through the PJM operation. Whether that, technically, makes PJM a counterparty, I'm not sure, in the legal sense, but to participate in the market, if you get to the target year and you don't deliver, then you pay the deficiency charge.

MR. SINGH: And if I deliver, who pays me the money?

MR. WELCH: It's paid through the market.

MR. SINGH: My understanding is correct, then.

My question is for Ben. I think it's an interesting study on volatility and its effects on cost of capital. Did you see anything out there that relates volatility to levels of long-term contracting?

MR. HOBBS: Long-term contracting for capacity?

MR. SINGH: No, the argument that lower volatility will give you lower cost of capital. I'd actually like to take it further and say that the cost-of-service ratemaking might even slow volatility, but I don't want to go there.

(Laughter.)

MR. SINGH: Since your a professor, I think I'm asking a more conceptual question. In the Australian market, the volatility is fairly high there.

There's a lot of long-term contracting, and we heard from Brian that long-term contracting is important for investment, and cost of capital is another factor.

But it seems like you could really have opposite arguments in both.

MR. HOBBS: So what's your question, Harry? I'm sorry.

(Laughter.)

MR. SINGH: My question is, does higher volatility give you more long-term contracts?

MR. HOBBS: It should.

MR. TIGER: If I could follow up with John Wallach with a couple of questions, first, you mentioned the 15 gigawatts that are in the queue right now, so everything's working in PJM.

We talked a little bit about finance. Is it financed? Is it in construction? Where does it stand? Where is it being built?

And is that consistent with some of the goals that are trying to be fulfilled in terms of the locational nature of RPM? And then I have second followup that I'd like to follow up with after he answers.

MR. WELCH: I wouldn't say everything is working in PJM.

MR. TIGER: But, specifically related to the 15 gigawatts that's out there, where is it being built? Is it actually close to being built?

MR. WELCH: I think what's in the queue, depending which queue it's in, each of those products are at different levels of development, and I don't have in front of me, what percentage or at what particular stage, whether they have an SSA or an ISA or whatever the other acronyms are, in the various study agreements.

I do know that, for example, according to PJM, at least the last time they provided this information, there was not a lot of new capacity going into New Jersey and I can imagine there are a number of reasons for that.

That certainly raised some concerns, that locational aspect of it.

MR. TIGER: My second question is related. You mentioned that there were inconsistencies with RPM's structure, especially the four-year-out nature and the SOS in Maryland. Maybe you could elucidate a little bit further.

You mentioned that the LSEs might be statutorily prohibited from doing it. You could maybe further elucidate that, as to why it wouldn't work.

MR. WALLACH: We have settlement agreements in effect in Maryland which limit contracts to terms of three years or less. Basically, for someone, for a supplier on behalf of load to hedge in the fourth year, they would have to speculate, go out and procure capacity in some form or fashion for that fourth year not knowing what their load obligation would actually be, and that's pretty speculative. And I don't know that there's going to be much of that going on.

MR. BANDERA: It would end up being just a pass through, so there wouldn't be any competition on that aspect.

MR. WALLACH: My point exactly. It will be a pass through. That means that load will be fully exposed to the price risk associated with that pass through.

MR. TIGER: How would that be different to how it is today without having the forward year. Presumably they're still exposed to that fourth year. It's just not being determined today.

MR. WALLACH: Suppliers who take on that risk and pay the premium, there is a benefit to avoiding that uncertainty and locking in at a higher price than you might expect that price to be in the future.

MR. MEAD: I had a follow-up question for Ben Hobbs. If I heard you correctly with regard to your study, you concluded that with a sloped demand curve compared to a vertical demand curve, you've got both more supply and lower customer costs and lower payments to generators over time.

MR. HOBBS: Conditioned on the exact location of the curve, but generally in the ranges we were looking at, yes.

MR. MEAD: If I understood you, this is a simulation and the general reason for this result is that suppliers like lower risk and with the sloped demand curve they have lower price volatility over time that, in essence, lowered the supply curve. Is that fair to say?

MR. HOBBS: Yes, not the way I've drawn it here, but that's precisely what happens.

MR. MEAD: Can you discuss a little bit the nature of the assumptions you made about either the nature of the risk aversion or the nature of the shift in the supply curve that got these results? Because I presume that with different assumptions, you might have gotten different results.

MR. HOBBS: With different assumptions, what you get is different degrees of response. But you still get the same basic response. The way the simulation is structured is that you've got a generator, an agent sitting there who has a history of energy and ancillary service prices and capacity prices and has capacity prices for the next three years and some forecast of energy and ancillary service prices; and they may be highly volatile, they may not be. That gets translated through a utility function that if curve represents the degree of risk aversion, if linear means that all you care about is your expected profit out of this, you get a risk adjusted forecast profit. The greater the volatility in the history of prices, the lower that risk adjusted profit would be. And, of course, the lower generally prices would be, the lower that would be.

So it's true a simple mechanism of a utility function that we adjust the actual time series of profits into a single number, that then gets plug into a function that says this is how much capacity I'm willing to construct given my risk-adjusted forecast profit.

So the key -- there are three key sets of assumptions: what series of time do you look at profits to get your forecast profit, what your utility function is -- I used a standard MBA-type constant risk aversion utility function -- and finally, that function that translates the risk-adjusted forecast profit into how much capacity people are willing to add. Those things are all unknowable, at least in a market which is incomplete, where you don't have all the hedges and all the contracts you want against risk. So the key thing in this simulation is to look at a wide range of possible values with a degree of risk aversion for the degree of investment response and response to profits and, finally, the ranges of years you're looking over this variation.

Do I ever see the vertical demand curve doing better than the sloped one? No. Sometimes they come very close, but very often they're very far. So that describes the mechanism of how the simulation works.

MR. MEAD: Is it fair to say you did some sensitivity analyses and for even small amounts of risk aversion you still get this result that any sloped demand curve gets you both greater supply and lower customer payments than a vertical demand curve?

MR. HOBBS: Right. But, of course, the degree will be a lot less. If the agents are perfectly risk neutral and there's no weather-driven uncertainty in loads and so forth, you get exactly the same answer depending on how you draw the curve from both the vertical and the sloped one if you draw them through the right point. Risk won't then matter. So it's all a matter of degree. The greater the amount of risk aversion, the greater the amount of volatility and the more the divergence will be. And I don't know what the right number is, but the order of the two, which one does better than the other, is always the same.

MR. WALLACH: I'd like to respond to that for a second and say, with all due respect, Ben, to the work you've done and to PJM -- I think they were the first RTO to undertake the type of modeling that we should be doing to look at what the impacts of demand curves are in the long term, the fact is that I don't think you can really make a meaningful comparison between the two cases that Ben was just talking about, a vertical demand curve case and a sloped demand curve case. And there's a couple of reasons for that.

First of all, there hasn't been any benchmarking of the model in particular looking at what the model would say in the near term as to whether, you know, that model is making a reasonable representation of what we know today about investor risk profiles. And so to say that well, you know, we have a model that tells us things, relative cases to each other, my response is well no, you don't know -- until you know whether your base case is reasonable, you don't know whether your comparison of the base case to another case tells you anything.

Secondly, as Ben said before, it's all about the interest function. We know Ben has described modeling after -- it looks to me like there were a couple of flawed input assumptions that dramatically affect or could dramatically affect the results for the vertical case in terms of the amount of volatility coming out of that case.

And, in particular, when you model the vertical demand curve case, he set the shortage price not at the CDR, not at what we have today, but at two times the cost of new entry, which is essentially two times the CDR rate that we have today. So right there, whenever the vertical curve case goes short, prices are jumping up to two times the CDR. So right there you've exacerbated your volatility associated with the case.

Secondly, there was -- at least back when we were discussing the modeling during the stakeholder process, the last set of runs assumed that new capacity offered into the auction at a price below investment cost. So the model assumes that new capacity is going to bid in at a price that is below levels to achieve profitability.

So as a result, what happens is that clearing prices come out at levels below profitable levels and, as a result, the model then says well okay, investors are not going to build new capacity because in the future they see that prices are below levels that induce profitable investment. So that forces the model into a bust cycle that drives up prices in the energy market scarcity levels, drives up capacity prices to two times the cost of new entry and then, you know, creates a boom cycle. So the flawed assumptions generate the outcome that you're seeing, which is a lot of volatility in the vertical demand curve case. And so frankly until we can get a model simulation that more reasonably reflects reality on the vertical curve case, I don't think you can really say whether the reduction in volatility from a sloped demand curve will actually produce lower total costs.

MS. COCHRANE: I'd like to switch gears for a minute. We have some other topics that we'd like to explore and we're running out of time. We will have --

MR. HOBBS: First of all, no benchmarking. If I'm going to make a precise numerical prediction of something happening in the future, benchmarking would be absolutely key. That can't be done; I'm not going to claim it can be done. That's why you look at an incredibly wide range of assumptions. Among the wide range of assumptions we looked at included different bidding behavior by the new generation, ranging from bidding nothing to saying we're going to put that in as a vertical supply curve to bidding $44,000 per megawatt, which is basically the net cost of new capacity. When you take out expected energy and ancillary services, John's right, that case should be considered. I have considered it. I'm sorry I don't have time -- I could have taken 15 minutes like some of the other speakers today and gone through those, but I think I was merciful not to. Sorry for the dig.

The other matter, the shortage price at CDR, we did simulations with lower prices, the vertical curves do even worse. You could push the multiplier on the CDR down to zero times CDR, guess how much capacity you'll get then? You'll get less capacity, more volatility because you have less capacity, and you're in the range of high shortage costs. It turns out the vertical demand curve does not do better from two times to one time.

All this will be documented hopefully in some sort of filing eventually. I'm sorry I didn't get the chance to talk about this today. I'll be glad to talk more off-line with anybody who would like to.

MS. COCHRANE: At the end of the day, we'll talk about next steps and opportunities for people to add more to the record.

MR. HOBBS: By the way, I welcome suggestions for sensitivity analyses. We've actually been dialoguing with a number of people in this room about this, and I welcome the analysis.

MR. KATHAN: I have a series of questions focused on demand response. Particularly, I wanted to direct them to Steve and Stephen and also to Tom, if you'd like.

The first thing I was struck by: you're both retail providers, you're both providing demand response but you're taking dramatically different opinions on the RPM. I'm wondering why. Is it because your different type of customers that you're serving, different types of technology? Can you provide --

MR. WEMPLE: To clarify -- and I think Steve hit it on the head -- the PJM ALM program, based on the current penalty and level of compensation, is fairly unattractive, so we are not selling any of that. We're actually advising customers don't sign up for ALM, it's not going to reward you very much and you've got this huge stick hanging over your head. We are very active in some of the locational markets in New York where demand response is able to get the full locational value and participate under special case resources, and we find it very compelling to talk to customers about the ability to hedge their own capacity costs, which are a measurable part of their supply costs that can be based on the New York capacity prices equivalent of 2 to 2.5 cents a kilowatt hour just in the capacity cost alone. That is significant for them, it gets their attention and, you know, I would suspect it's perhaps the different markets that we're operating in.

MR. FERNANDS: It may also have something to do with our generation portfolios in New Jersey. People should advocate for their business interests, and if you own a significant amount of merchant generation in New Jersey, you should be in favor of RPM.

MR. KATHAN: Following up, are your customers ones that are large industrials who are interested in responding in more of a voluntary or more of an ADRP, like it is in New York, or are they ones that are involved in the ALM?

MR. FERNANDS: I can expand a little bit more about my particular group of folks. They range from cooperatives and municipals that have air conditioning and water heater programs that use it to reduce their capacity costs. And traditionally some of them participate in ALM, some of them use it to reduce their peaks and participate in PJM's pilot program or have historically participated in that. Some of them have bid in the day-ahead market and some in the real time, both large industrial customers as well as actually residential programs. So a fairly broad variety in PJM.

I would agree with Steve that the capacity non-performance rules in New York are much more favorable as opposed to the penalty structure in PJM. I have a broad group of clients in demand side response.

MR. KATHAN: I guess I wanted to get what Tom had mentioned and I think what was earlier stated, the types of technology that would be coming out inside of an RPM. Do you believe there would be an increase, any increase in the amount of demand response brought into the market if you now have a four year procurement requirement. Under the various outs you have, does that provide enough of an incentive to invest in technology, invest in a longer-term investment?

MR. FERNANDS: Steve made a valid assertion. People can essentially not participate in the markets and then, on a very short-term basis, can opt out of the RPM and can look ahead four years and say okay, if I opt out of RPM, opt out of the capacity market, I'll know what my avoided cost will be for the next four years if they have some relationship to a load-serving entity that allows them to do that. There could be that opportunity. Just from the clients I've talked to, I haven't found anyone that's like that.

The Neenan study is probably the most comprehensive, because it looked at New York, New Jersey, and PJM. As far as a survey that I know of that goes outside of the folks I know, everything I've heard in that study indicated that no, it would really be a reduction in demand side response participation. But again, that's based on those sources.

MR. WEMPLE: And the point/counterpoint, I think the Neenan study was looking at the four year forward. Since demand response under the ILR program can participate with three months' notice, I don't believe the conclusions in the Neenan study are applicable to the PJM proposal because they really focused on the older CRAM proposal.

In terms of the customers we work with, you've got customers who can currently curtail because they have backups already in their facilities, hospitals, financial institutions with critical processes, those are the ones that have virtually no lead time because they had that capability to begin with; there may be some internal wiring.

You have other customers with the right market valuations and I think that comes from defining the locational markets as well as having a rational demand curve, so they have some consistency of revenue streams, are likely to make investments in curtailable measures. We actually buy curtailable measures from other suppliers who are more creative than we are. There's one shop who basically hands out movie tickets and sends an apartment basically to the movie next door on hot days and curtails that way.

(Laughter.)

MR. WEMPLE: Hats off to them. That's what markets are all about. If someone can come up with a better idea, I'm perfectly happy to buy the capacity.

MR. KATHAN: Anyone else? Tom?

MR. WELCH: I'll just say it seems to me one of the intuitive advantages that RPM, with its forward component and forward identified price, will bring is if I'm trying to develop a demand product of this kind, I have a price target to look at far enough in advance so that I can develop a plan and sell it to somebody, you know, in the three month ahead situation with some indication of what the value of it is going to be. One of the impediments we've heard is that people just have no idea how they'll be able to capture the value of demand if they develop some sort of business plan around it and RPM provides a price signal for a particular component of value they will bring into the market that right now is absent in the much shorter term market.

MR. FERNANDS: One of the struggles with that concept, though, is that there's no one to sell it to. Yes, you now can opt out, but all the load-serving entities have bought their capacity or PJM bought on their behalf, all the capacity. It's a question of, unless I'm my own load-serving entity, some large industrial customer, my own load-serving entity, and I can avoid the costs, if someone else has already bought on behalf of mine and everyone else's load-serving entity, that capacity obligation, I really need to have something with my load-serving entity.

So, I'm served by PECO Energy, I'm under a fixed rate with them, and I suddenly say, okay, I'm on a fixed-rate tariff rate, and I say, okay, three months ahead, I can do ALM. Right now, in ALM, I can trade, then sell into the market, another provider can pick it up. It doesn't have to be that load-serving entity.

The only value, if I decide to respond, is to PECO, and PECO, in their rates, may not have that we're going to pay you to do that, in fact, quite the opposite. So, there are inconsistencies. I can go into that in more detail, but I have a feeling that you don't want me to.

(Laughter.)

MR. O'NEILL: Steve, you said something very, I think -- at least it struck me as interesting -- the reason why you and Steve differ on your positions, is because you have different current portfolio positions.

How much of this is about current portfolio positions, and really not about the long-term health of the PJM market?

(Laughter.)

MR. FERNANDS: I'll let you give the last word on this one, if you want.

MR. WEMPLE: Our affiliate owns 600 megawatts of generation in PJM, and our load positions are in excess of that, so if I were to argue for a higher capacity cost tomorrow, it will cost my company more to hedge my load, than I would get from my generation side.

Our positions, what I think we've always tried to advocate for, we want a solution that's going to work in the long term and bring everything together. We can't focus one month, six months, or even a year down the road.

We've made a corporate investment to sell retail. We hope to be around doing that for the next 20 years. We've made a corporate investment to invest in generation, and I hope those plants are going to be around for more than 20 years.

We're in it for the long haul, Dick.

MR. FERNANDS: By and large, my clients tend to be municipals, cooperatives, people that are also going to be around for the long haul, and tend not to react strongly to short-term impacts.

That being said, just as you're analyzing the comments, although everyone is supporting reliability here, it seem coincidental that a lot of the utilities that have resources east of the Eastern Interface, view reliability being served most economically, one way, and people that own physical resources west of the Eastern Interface, view getting to that same point, a different way.

Also, although most load east of the Eastern Interface is served by market-based rates that get adjusted each year, and, therefore, increases or decreases in prices get passed through to the customers, as opposed to swallowed by a load-serving entity with long-term contracts, the exception, of course, being municipals and cooperatives, that customers don't just switch; they stay long-term, and if their costs go up, they have to pass those on to their customers.

MR. BANDERA: Steve, just a quick question: You brought up the position situation and how that might deter your incentives to support or be against this. Would your situation potentially be one where you're short on capacity for your clients, and, if we switch to RPM, that would work against your situation?

MR. FERNANDS: Our clients -- again, my comments were for us as a consulting company, as opposed to any of our specific clients -- they range the spectrum in terms of where they're physically located across the systems. We have folks in Chicago, we have folks in the Delmarva Peninsula, and most everywhere in between.

We have people that have capacity positions that are exceptionally long and we have people who have capacity positions that are exceptionally short.

So, we really do have a variety of positions. Most of our people both have physical generation, as well as financial contracts that make up their portfolios, so we don't necessarily have one specific dominant strategy, per se.

MR. SCOTT: As one of the clients and one of the cooperatives that has a great deal of generation, mixed baseload, new coal, CT, sometimes with that buyer, sometimes we view it that we can manage our risk.

We look at RPM as kind of a non-market or administrative solution, and if we're going to solve resource adequacy with an administrative program, then, okay, let's do that. I'm not suggesting integrated resource planning and segmenting by asset classes, but if we're really going to have an administrative solution, let's do one. Otherwise, let's facilitate a market-oriented solution.

I mean, we and others who build, and anybody else in this market, can already cap their exposure. The net costs of merely creating the CT in a period of surplus here, automatically, arbitrarily, and administratively riding up the value of capacity, you haven't exactly done me a favor here that I can't already do for myself.

So, it's a view, it's a philosophical view that it's not a healthy market design, from a long-term point of view. We own these assets on our balance sheet, and we have a long-term interest, we have no reason for being shortsighted and artificially impeding the value of generation or interfering with the adequacy of the system.

MS. COCHRANE: Thank you all very much. I know a number of you have travel arrangements, and we have the room only until 5:00, so I don't want to run too much over that.

It's been a long day. We've addressed a lot of very difficult issues. Don't walk out yet, Joe.

(Laughter.)

MS. COCHRANE: I'm not done yet. You might want to hear this.

At any rate, we had set aside a relatively large block of time in the afternoon that we'd hoped to kind of recap. Well, we'll have to do that real quickly now.

To sort of recap a bit about what I think we've heard as points of agreement today, there's a lot of disagreement, but I think there is also some points of agreement today.

For the most part, people agree that the current capacity construct isn't meeting everybody's needs, and perhaps needs some changes.

I think we heard a lot of agreement that there are changes that are needed to the transmission planning process, and I think there are some statements by PJM and some changes that have already been made, and perhaps more can be made to integrate transmission planning with capacity markets and with demand response and other aspects that we've heard.

There seems to be a general agreement, for the most part, that there needs to be a look at the locational needs of different parts of PJM's system and in designing capacity markets to address the shortages in certain areas.

There may be more areas of agreement. I think there are a lot of areas of disagreement. One thing I'd like to do is to respond to a statement that was made by Tom Welch and others that support the RPM. They have said -- Tom, you said that you think there's sufficient understanding of the RPM proposal, so, you know, we should go ahead and file it at the FERC.

I think there is understanding of the proposal, but there's not necessarily agreement with it, though. And, as Commissioner Brownell said, we're here to make tough decisions, and we recognize that we don't get very often, things before us that have complete agreement.

There is disagreement on a lot of aspects, and we're here to make a tough decision. We'd rather have something come to us that has a bit more consensus, so that we don't have to make as many tough decisions.

And we don't want to have something that is going to have to spend a lot of time in hearing. You all are well aware of the experience that has recently completed with your northern neighbor. That was a very expensive and time-consuming effort, and it's something that we would like to avoid, for the most part.

I hate to say this, but we urge you to go back to your stakeholders. We would like you to file comments.

I also realize that there are people who wanted to speak today, obviously we had a very full day and we weren't able to accommodate everybody who wanted to speak today. But if you could file comments to us within 20 days under this docket number, and especially if you wanted to address some questions that were raised that maybe you'd like to answer.

What we would especially like to know is areas of agreement, suggested areas of compromise, ways, directions that the debate can be carried a little bit further. We understand and recognize that the PJM board is looking at this record. They have said, in Phil Harris' letter, I think, to stakeholders that they were looking to see what the record is developed here. That's primarily why we're asking for the comments and suggesting that you try to work through and develop this proposal further.

Did I miss anything, Derek?

MR. BANDERA: No.

MS. COCHRANE: When I said file in 20 days, I looked on my calendar, that's July 7th. The reason why we're saying 20 days is we want you to have the opportunity to get the transcript. As mentioned in the notice, you can get the transcript from Ace Reporting. I guess if you gave him a card, he could make sure that you could get it quickly, or there's also a phone number in the notice, or you can call and you can also get it. Otherwise, we get it through our contract. We'll put it on our new E-library system seven days after we receive it from them. There's a bit of a delay if you want to get it for free off of our website. If you want to get it quickly, contact the Ace reporter, he'll get it for you.

Finally, just as a procedural matter, my attorney has gone but left me a note there are a couple of more dockets -- proceedings that were mentioned off to the side. We tried to add a couple to the notice that we thought might get mentioned, just to cover ourselves. There were a couple more that were mentioned that we'll also add to this proceeding. One is the RTO1-2 docket. PJM, also a New York ISO proceeding, ER04-1144, having to do with their planning process. We may also put the AD05-3 proceeding in this because of the discussion about the project, Mountaineer, from the coal proceeding.

That's my wrap-up. Almost made it before 5:00. Anybody else have anything they'd like to say?

(No response.)

MS. COCHRANE: I very much appreciate the discussion and patience with me as I tried to move things along. Thank you very much.

(Whereupon, at 5:05 p.m. the conference was adjourned.)