BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

- - - - - - - - - - - - - - - x
In the matter of: :
TECHNICAL CONFERENCE ON : AD13-7-000
CENTRALIZED CAPACITY MARKETS :
IN REGIONAL TRANSMISSION :
ORGANIZATIONS AND :
INDEPENDENT SYSTEM OPERATORS :
- - - - - - - - - - - - - - - x

Federal Energy Regulatory Commission
888 First Street, Northeast
Washington, D.C. 20426
Wednesday, September 25, 2013

The technical conference was convened, pursuant to notice, at 9:03 a.m.,

Court Reporter: Jane W. Beach, Ace-Federal Reporters, Inc.

PANELISTS I:

ROBERT ETHIER, ISO-NE
RANA MUKERJI, NYISO
ANDY OTT, PJM
JOE BOWRING, MONITORING ANALYTICS
DAVID PATTON, POTOMAC ECONOMICS

PANELIST II:

DAN CURRAN, EnerNOC
LEE DAVIS, NRG ENERGY INC.
JULIEN DUMOULIN-SMITH, UBS INVESTMENT RESEARCH
JAMES JABLONSKI, PUBLIC POWER ASSOCIATION OF NEW JERSEY
RICHARD MILLER, ConEd
ROY SHANKER, INDEPENDENT CONSULTANT
TODD SNITCHLER, CHAIRMAN, PUBLIC UTILITIES COMMITTEE OF OHIO

PANELIST III:

JEFFREY BENTZ, NEW ENGLAND STATES COMMITTEE ON ELECTRICTY

ROBERT ERWIN, GENERAL COUNSEL, MARYLAND PUBLIC SERVICE COMMISSION

JAMES HOLODAK, NATIONAL GRID

JUDITH JUDSON, ELECTRICITY STORAGE ASSOCIATION

SHAHID MALIK, PSEG ENERGY RESOURCES AND TRADE

WILLIAM MASSEY, COMPETE COALITION

JOHN MOORE, THE SUSTAINABLE FERC PROJECT

ED TATUM, OLD DOMINION ELECTRIC COOPERATIVE

PANELIST IV:

PETER CRAMTON, UNIVERSITY OF MARYLAND

MICHAEL HOGAN, THE REGULATORY ASSISTANCE PROJECT

SUSAN KELLY, APPA

MICHAEL SCHNITZER, NORTHBRIDGE GROUP, EPSA

SUE TIERNEY, ANALYSIS GROUP

JAMES WILSON, WILSON ENERGY ECONOMICS

P R O C E E D I N G S

(9:03 a.m)

MR. DENNIS (presiding): Good morning, and welcome to today's technical conference on centralized capacity markets in regional transmission organizations and independent system operators in Docket No. AD-13-7-000.

I want to thank all the participants for being here today for what I'm sure will be an informative and lively day of discussion. I also want to welcome the Chairman and Commissioners, and Commissioner Moore unexpectedly could not be here today. He very much wanted to, and sends his regrets for not being able to be here, due to a last-minute conference.

Just a couple of reminders, as I mentioned just a second ago. Hearing Room 2 is the overflow room; plenty of seats there for those in the back. If you have bags as well, we ask that you take them to Hearing Room 2, just so that we have plenty of room in the aisles here as well.

Lastly, if you could please turn off cell phones. They cause interference with our audiovisual equipment. That would be great.

The purpose of today's conference is to consider how current centralized capacity market rules and structures in the regions served by ISO New England, New York Independent System Operator, and PJM Interconnection are supporting the procurement and retention of resources necessary to meet future reliability and operational needs. While the Commission recognizes that other regions are considering similar issues, today's technical conference will focus solely on the centralized capacity markets in ISO New England, New York ISO and PJM. Should the conversation stray into other regions, I will be steering panelists back to the three regions at issue in this conference.

Additionally, while this conference is not for the purpose of discussing or hearing argument regarding specific cases before the Commission, we have provided notice of certain pending dockets in notices issued on August 23 and September 24 to insure that we comply with the restrictions on ex parte communications. However, to the extent discussion veers into the specifics of pending cases, I will bring the discussion back to the broader topics at hand.

After hearing opening remarks from the Chairman and Commissioners with us today, we will proceed through four sessions. In the first session, representatives from ISO New England, New York ISO and PJM will provide a brief overview of their centralized capacity markets, including the goals and basic structure of these markets, and discuss how each market is achieving its stated goals. Independent market monitors for each RTO and ISO will also provide an assessment of the functioning of these markets.

Following this opening session, the three sessions that follow will discuss the basic elements and mechanics of current centralized capacity markets and their effectiveness, the impact of emerging issues and external forces on the goals and objectives of these capacity markets, and potential future directions for those markets. The panelists for each of those sessions have pre-filed their opening statements, and will not be making opening presentations. Instead, after introducing them, I will turn to the Commissioners for questions.

We will break for lunch from 12:30 to 1:30, and there will be a break in the afternoon from 3:00 to 3:15. We plan to wrap up around 5:00 p.m.

Following today's technical conference, the Commission plans to take comments from the public on the issues discussed today. The Commission will issue a subsequent notice with more information.

We have a lot of ground to cover in a short amount of time today. While the issues covered in each panel overlap to some extent, we'd like panelists to keep their comments within the topics laid out for each panel. If the discussion begins to stray outside the scope of the panel, or outside the scope of the question, I may be interjecting to bring the discussion back on topic.

Let me close with just a few housekeeping matters. We discussed Hearing Room 1 is the overflow room. Please, no food or drinks other than bottled water in the Commission meeting room. Hopefully, you mainlined your coffee this morning, like I did.

There are bathrooms and water fountains behind the elevator banks on each end of the building. And again, please turn off all cell phones to avoid interference with the audiovisual equipment.

For panelists, if you would like to be recognized to speak, please place your tent card up. Be sure to turn on your microphone and speak directly into it. When you are not speaking, please turn off your microphone to minimize background noise.

Finally, since we are addressing three markets with somewhat different labels for various centralized capacity market design elements, please define any acronyms you're using, or better yet, avoid using them where you can.

Let me now turn to the Chairman and Commissioners for any opening remarks. Mr. Chairman?

CHAIRMAN WELLINGHOFF: Thank you very much, Jeff.

Well, it's interesting to see that this sleepy little Commission has finally become a subject that people are interested in.

(Laughter.)

CHAIRMAN WELLINGHOFF: We have a few people in the audience here. One thing I want to let you all know: I am unfortunately going to have to leave at 4:00 o'clock today, not that I don't want to stay till the end of the session. But I have a meeting up on the Hill which is predetermined that I have to go to, so I will not be staying till 4:00 o'clock.

But I want to tell you I'm very interested in hearing the panel today, because I do think capacity markets in this country are extremely important. Can you hear me out there, Greg? No? Okay, have we got the body mike for some reason here? I've got the mike on here, but it doesn't seem to be doing it.

(Pause.)

I'll try to speak a little louder and project here. I apologize. I think capacity markets in this country are extremely important, and I think that what we're doing here today, the examination of those capacity markets, is an important watershed. I think it's necessary for us to look at all aspects of those markets to determine whether or not there's provisions of them that need to be modified. I think we have seen great successes. A number of the RTOs, we currently have capacity markets, but I think we've seen other areas where we've had less than successes. So we certainly need to build on those areas of best practices and insure that those best practices can be spread throughout the RTOs.

I believe that in doing that, we can insure, number one, resource adequacy and reliability, which is one of the main charges of this Commission, but also that we can insure cost-effective resources delivered to consumers, and that's another charge of this Commission.

So I'm looking forward today to comments from the panelists, especially those comments relative to other aspects of the capacity markets that we've asked some questions on, including things like locational issues regarding capacity markets, and ramping rates, where capacity has different characteristics, and how different characteristics should or may not be recognized in capacity markets. I know there's a difference of opinion from the written testimony that I've read with respect to that.

I'm very interested in that, because I think because of the dynamic characteristics of our overall energy system, and how it's changing so rapidly, especially people moving very rapidly to distributed generation and how that's affecting markets all over this country, we need to know how the centralized markets will respond to that, and respond to that in an effective way that again can insure that the overall system operates reliably, efficiently and cost-effectively.

With that, I look forward to hearing from all the panelists. Thank you.

COMMISSIONER NORRIS: Thanks.

I don't have much to add, other than just thank you for being here and everyone's participation. But the thought did occur to me, as I was meeting with my great staff yesterday, and we were going over questions and the testimony, was to say this: I've talked to folks out and about in my travels since we announced this technical conference. It's amazing how much you all read into what we're doing.

I'd just say this conference, it is what it says it is. Folks who think we have some other agenda in what we're doing here, I'd say rest assured. Our intention here is to find out if this is working well, how it's working, what changes may be needed to be made. And as Jon said, with the dynamics of the system changing rapidly, what adjustments need to be made to make sure we're delivering resource adequacy in a cost-effective manner?

Along that same line, as I was asking questions, we were talking about this yesterday. I would probe and be the devil's advocate on questions, and they were very worrisome I might ask it that way today, and you'd read something into an agenda. Let me just say, I'm going to be devil's advocate here today on a number of things. Don't read too much into it. It's just part of really getting to the intellectual argument here of what is the best way forward, and what adjustments need to be made.

We've obviously touched a nerve with this conference, an important topic to raise and discuss that impacts consumers throughout the three eastern RTOs and ISOs. So I look forward to our conversation today, and hope we have just a very open, transparent conversation about what needs to be done, if anything, changes in these capacity markets.

Thanks.

COMMISSIONER LA FLEUR: Thank you, Jon.

I'm very happy to be here. I appreciate all the witnesses and all the folks who came in for the conference. One of the things that I think is our responsibility as Commissioners is to be alert to trends that we're seeing in all the cases that flow by us, trends in the industry, and try to think about when we should do things on a case-by-case basis in a specific adjudicatory docket, and when something might be ready for generic action.

During the time I've been on the Commission, we've issued literally dozens of orders on capacity markets, and some of them were as narrow as the treatment of one 15 kW fuel cell in one specific auction, or how some specific increment of municipal taxes affected co-own. And at times, I felt a little bit like the blind man and the elephant, that I was looking at such a small piece of the capacity markets, and we needed to step back and take a bigger view.

There's a lot of overarching issues in play, and in my mind, first and foremost is reliability. These capacity structures exist to facilitate forward reliability products to attract capital to build the resources we need to maintain a reliable grid. At the time when we went into industry restructuring -- I know tomorrow Harvard has its 20th anniversary of when they started talking about it -- when we went into this, the whole country and most of the regions were very, very long on capacity. In fact, that's one of the criticisms of the old system, right? Companies overbuilt; too much capacity.

But that situation has changed or is starting to change since then, as the country is undergoing really significant changes in power supply due to the boom in natural gas, due to environmental regulations, and due to the renewable standards in so many states. So I think we're entering a period where we just can't count on being long, and we'll start stress-testing our capacity markets. So it's appropriate to look under the hood and see how they're working.

I want to thank the Chairman for devoting the time and resources to put together today's conference, which were considerable, and the staff for their hard work in doing the paper and preparing for it. I just wanted to highlight a few themes that I'm really interested in hearing about as we go through the day.

The first, which was the subject of the NESCO concurrence that launched the discussion, is how we can address the tension between a resource-neutral single clearing price market that uses a single clearing price to decide what you pay for, and states and localities with specific resource preferences like renewable portfolio standards. They both exist. What are we going to do about that?

Secondly, are there specific -- and I mean specific market design elements that help or hurt with that issue or other issues, rather than just talking in generalities? Are there things we should be looking at in design of these markets?

And finally, I'm interested in any thoughts on where we go from here. Are there specific streams of work that are going to come out of today that we want to have another conference or look more into, or is this just to kind of inform us, and we'll go back? I'll be alert to sponsor anything that we should do coming off of this.

I think all the panelists submitted excellent testimony. You can assume that we've read the testimony, and you know that we know the basic views that you filed in all those dozens of dockets. So I'm hoping we can get beyond what we already have heard a million times, and really hopefully have all these smart minds engaged together on the panel.

So, thank you very much. Excited about the day.

COMMISSIONER CLARK: Well, thanks, everybody, for being here, and welcome. I won't take up too much time with opening comments, because I know we do have a long day ahead of us, and we'll probably be covering things that might otherwise take about a week's worth of meetings over the course of the next few hours.

Probably over the last year, my first year on the Commission, I've spent as much time boning up on capacity market issues as anything else. A lot of it's probably the result of the particular region that I come from, which is not a capacity market region of the country. So I felt it incumbent on myself to get up to speed on some of the issues that are facing some of these eastern RTOs and ISOs as they work through what is still a relatively new construct in terms of regulatory models.

As with any new construct, we are I think all learning from each other. Each of these are a little bit differently. Like Commissioner Norris, I've traveled around the country and talked to stakeholders. I too have sensed a lot of curiosity, interest, perhaps angst about what the Commission may be doing with this particular tech conference that we're having. But I would just reinforce what my fellow Commissioners have said.

I look at this almost like a -- kind of like your regular checkup with your physician. It's just something you should probably do as a matter of course of good practice. You might kind of ask how things are going, do a little blood work. You know, maybe one ISO's doing really well. Maybe another's got too high cholesterol. I don't know.

(Laughter.)

COMMISSIONER CLARK: But the idea is just to get a sense of how things are working. Have we learned best practices from each other? Can we do better in some areas or do we need to hit the reset button on some others? So it's an open-ended question, but it's one that I think is very worthwhile given the amount of interest, obviously, that we have in these particular topics.

So thank you for being here today. I look forward to a great day of discussion.

MR. DENNIS: Thank you.

Our first panel is, the role of centralized capacity markets in assuring resource adequacy. We have representatives from ISO New England, New York ISO, PJM, and the independent market monitors here. Let me introduce them, and they will begin their presentations.

The RTO/ISOs have 15 minutes each, and the independent market monitors have ten minutes each. First we have Robert Ethier, from ISO New England; Rana Mukerji from New York ISO; Andy Ott from PJM, Joe Bowring from Monitoring Analytics, and David Patton from Potomac Economics.

Mr. Ethier, when you're ready.

STATEMENT OF ROBERT ETHIER, ISO NEW ENGLAND

MR. ETHIER: Thanks for the opportunity to be here today. I appreciate the opportunity to share New England's experience. I think we have a lot of experience to share, some of it good, some of it sort of the hard sort of experience that you learn from, and hopefully learn what to do better in the future.

I look forward, of course, to any questions on issues that I don't go into detail about. I appreciated Commissioner LaFleur's remarks. I am not going to read my lengthy submittal, so you can rest assured that I won't be doing that.

What I do hope to do is give you a brief overview of how our current markets work, and really the issues we see going forward. New England is engaged in very involved subdiscussions right now about how our markets are going to evolve, and I think it would be useful to highlight that here.

I'll start by saying that I think capacity markets are important and I think they're necessary. Unless we want to go down the path of Texas and trying to do it with an energy-only market, a capacity market is really the only alternative. I know there's a lot of concern about capacity markets. There's a lot of concern that they have administrative aspects to them. But fundamentally, capacity markets are needed to address reliability standards, and those are administrative in nature. So it's not a surprise that we need some sort of market superstructure to insure that we meet those reliability standards.

Our current market is a market three years in advance of the delivery period. So we run an auction for all capacity a little over three years in advance. All resources are able to participate in the market. That's wind, that's demand resources, that's traditional generation, that's imports. We're open to all comers.

We are working hard, actually, to make all those resources treated equally. Right now, they have somewhat different rules, but we I think are consistently moving in the direction of equal treatment for all resources, to have a level playing field.

We have a zonal construct in New England. Currently we have four zones that may or may not experience different prices depending on the quantities and the prices offered in each of those zones. We have a vertical demand curve, not a sloped demand curve as other regions do. That means that we seek to buy just the amount of capacity that our reliability standards say we need, which -- I won't be the first one to use an acronym -- it's our installed capacity requirements that we seek to meet with that vertical demand curve, which is our local reliability standard for resource adequacy.

We measure performance during shortage conditions. You may recognize that that's an issue of debate right now in New England, and one of the things I intend to talk about more later is, when do we measure resources, and when we measure those resources, how do we either reward or penalize their performance during those time periods.

Our view is that the New England capacity market has actually worked well to date to get us the resources we need. We've met our installed capacity requirement every single year. We have not had any reliability, any outages as a result of insufficient capacity. So in that sense it's worked well. We've actually had zonal price separation. In our most recent auction, one of our local areas was short of capacity, and it cleared actually at a rather high price, because new entry was needed.

So at a high level, I think it's fair to say that the market is sort of working as designed, and we've also made a number of significant improvements since the markets started. Three of those, which the Commission is quite familiar with, because you all approved these changes, are improving the zonal modeling. When we first started the markets, it was relatively difficult to create zones. Now the zones are modeled all the time. We have a MOPR, Minimum Offer Price Rule, that limits the price at which subsidized new resources might enter the market, and we did eliminate the price floor as well in the upcoming auctions.

So those are three areas where I think we made a great deal of progress in improving the market design. We have more areas to go, however. What I'd like to do is spend the rest of my time on what we need to improve going forward, and it's really sort of the three Ps that were laid out in the staff white paper. I hope that doesn't count as an acronym.

Product definition, performance and price formation: those are the three things that most urgently need addressing in our market, is my belief. I think the staff white paper did a nice job of laying out those issues and highlighting those as things that need to be addressed in many of the markets, and certainly in New England.

Why do I say that those things are important for

New England? Really, because our experience running the system using the current capacity market and the current definition of each of those things. So we have in our view, in the ISO's view, had relatively poor resource performance despite the fact that we've actually been long resources for the last seven years. So we've had a number of close calls, close reliability calls despite the fact that we have far more capacity than our installed capacity requirement would lead you to think we really need to run the system in a reliable way.

We think this is because the current capacity supply obligation is kind of an empty obligation. It's not that there's zero obligations. It's that they're too low to achieve the reliability and the resource performance that we want. We think we need to improve those things.

A couple of examples why we think that's the case. New England, as I'm sure you all know, is at the end of the gas pipelines, and with the low-cost Marcellus shale that's come in, our pipelines from the west into New England get constrained in the wintertime. This has happened for a couple of years now. We get very high gas prices. We get limited gas availability, and we've had many, many cases, as the Commission well knows, of resources that weren't able to get gas in a timely way or in an economic way.

Yet, despite this, we've seen a notable reduction in dual fuel capability in New England. We talked to the resource owners and they say, "There's no money in it. Why would I keep it? I don't get paid for keeping this. There's no real economic incentive for me to keep it around."

Another example is, resource owners acknowledging that they are reducing their maintenance budgets for their capacity resources, because there's not enough money. To me, that's a signal that to provide capacity, you don't need to do good maintenance on your unit. That's a fundamental flaw. That's something we need to fix.

When improvements are needed, we need to define the product in a clear and simple way. What's the capacity resource agreeing to do by being a capacity resource? Right now, it's definitely not as clear as it ought to be. We're hoping to improve that product definition.

Two, we need to value performance appropriately. Under our current market design, resource performance is not valued at a high enough level to incent folks to do good maintenance, to incent folks to keep their dual fuel capabilities, to incent folks to engage in long-term contracting or in advance contracting for natural gas. Those things should, you know, come with the territory. Not that we want to specify how it's done or exactly what every resource does. We want to stay away from that. But our view is, we're not providing adequate incentives for folks to do that, as evidenced by the fact that they're not doing that. Yet we believe we need it for reliability reasons.

Finally, price formation. Price formation is sort of a nice way of saying, price volatility in our market is an issue. With a vertical demand curve, you're very likely to see a boom-bust cycle. One of the reasons we've had a price war for, unfortunately, seven auctions is the fear of exactly that sort of price volatility; that all of a sudden, a lot of capacity will leave the market at once, and we'll have very high prices. But until we get to that point, we'll have extremely low prices, and that volatility is not good for the kind of long-term investment that you need in these markets.

A sloped demand curve, in the view of many folks, would be helpful. It would also, in our view, help ease the discussions around what you do with resources that are intended to meet state policy goals. So, those resources clearly have an effect on the market. A sloped demand curve doesn't make those effects go away, but it certainly works in the right direction in terms of addressing those effects.

What is it that we are talking about with stakeholders right now? We're looking at increasing the performance incentives in our market in a way that we think is actually quite simple, and actually quite consistent with the way other commodities markets work. So essentially, the capacity market would be the forward sale of energy on high energy price days, sort of that simple.

Forward sales of commodities are quite common, and the way they are settled out and the way they are transacted in value is actually pretty standardized, and we would like to adopt that model. The nice part about it is, if you do that, what it really does is, it replicates the incentives of the energy-only market, which I think you're probably all familiar with, and most economists agree are the right incentives to apply to resources, but it does it in a way that it smoothes out the expected revenues for a new entrant or a new resource. And it does this because you sort of lock in the average expected revenues in a future year, so when that year actually occurs -- if it's especially hot or especially cool -- you have lower prices or higher prices. The resource owner is not -- their revenue stream is not affected by that to nearly the degree, because they've sold their commodity forward.

That's why farmers sell their commodity forward; so that they're not subject to the volatile swings in commodity prices. We'd like to adopt the same model here. We think it's important also because this would provide meaningful obligations and consequences. If you don't deliver the product at the time we need the product, and it's going to be well defined when we need it, you sort of sell back essentially that product just like you do in a forward market.

So, if I sold grain forward, and I don't deliver the grain I told you I was going to deliver, I have to then go buy grain at the spot price and fulfill my obligations. A similar approach here.

So what objections are we getting? You know, to date, it sounds like not an inappropriate course to take. A number of objections, of course. First is that it's going to cost more, and the answer is that it will. It will cost more than the status quo, but it'll cost more because we're saying you're actually going to get something for your money. The capacity product is going to be much more meaningful, and you're going to get much more reliable delivery of the product than you do today. And that increased service costs more. The flip side is, the system will be more reliable.

Second, naturally, there are winners and losers among providers of capacity, and the folks who don't think they'll do so well under the new system where performance is valued highly don't like the new system. The flip side is, there are a lot of resources that go, "Geez, I'm finally getting valued appropriately for my high-quality capacity resource."

And then third, maybe a more widespread view is, to the extent that we have a capacity system that has an empty obligation, virtually everybody providing capacity kind of has to continue to provide that product, continue to get paid, and have very low risks. Because we're ratcheting the risk up on everybody, we certainly hear concerns about that.

So finally, in conclusion, we think our new direction will improve the resource selection in the market, because resources that are the worst capacity providers, have the highest risk of providing capacity, are the most likely to leave the market; that new resources are going to be the ones that can provide capacity most reliably, which seems like a good outcome when we're designing capacity markets. And then finally, that this is going to provide the revenue for suppliers to make the operational investments we want them to make. They'll continue to decide what the most cost-effective options are. Should I put in a package boiler to reduce my start time? Should I bring dual fuel capability, et cetera. But those will be left up to the marketplace, but we'll provide the incentives and the revenue stream for that goal.

That concludes my comments. I welcome any questions. Thank you.

MR. DENNIS: Thank you. Mr. Mukerji?

STATEMENT OF RANA MUKERJI, NEW YORK ISO

MR. MUKERJI: Thank you for the opportunity to participate in this technical conference.

I will start with a page out of Bill Hogan's market theory, which says that the role of the market is to provide signals, which is the price, which enables private investment to happen, and the private investment sustains the market and preserves reliability. If you look at the energy market, the energy market is very much aligned to the physics and operations of the system. It clears every five minutes in New York, and you have 400 nodes. We have a nodal five-minute settlement market, so it's much closer to the limit in actual operating considerations.

The capacity market, as Bob mentioned, is based on a planning construct. It's based on assumptions, forecasts, and it is in fact a planning artifact. So whenever you have a planning artifact and you're doing a market based on assumptions and constructs, you will have -- inherently you have no controversy. That's a good thing, that's a salient point to recognize.

And one of the things that Bill Hogan has always recommended is, give more money in the energy market to scarcity pricing. Because in the energy market, if you're running out of reserves, your scarcity pricing goes up, and then it's more locational, it's more targeted, it's more real.

We do not believe that you can do away with the capacity markets. In some markets, like in Australia, they have just the energy-only market. We believe that a capacity market is necessary, because the planning construct is, we want an assurance for fuel adequacy for a future date. But we have to recognize that, because it's an administrative construct, it is more controversial.

So, when we talk about changes to the capacity market or looking at things like fuel adequacy or fuel assurance, what we believe is that we should tackle the energy markets first, give the proper energy market signals and the scarcity pricing, before transferring requirements in the capacity market, which by its nature is administrative.

In the New York market, we formed the capacity market in New York -- since 1999, New York has been in operation. In the earliest ISOs, the capacity market was started right away. We recognized the fact that capacity markets need to be locational. You cannot supply capacity in New York City from power plants in Buffalo. There are transmission constraints. So just like an energy market, you have 400 nodes. In capacity markets, we started with three zones. New York City was a zone, Long Island was a zone, and the Control Area was a zone.

We are in the process of identifying a new zone, which we call the New Capacity Zone, which includes the lower Hudson Valley and New York City, because that has evolved into a load pocket and needs its own unique signal. However, New York has had this locational design since its inception.

The other part of New York's market design was a sloped demand curve. When we started the capacity market, we started with a vertical demand curve, and what we had was a bust and boom. When capacity is short, the prices are very high. When the capacity is even slightly long, the prices go to zero.

Actually, it was the economics that our Public Service Commission, who proposed in a technical paper a sloped demand curve which mimics the elasticity of demand. So on days when supply is long, the prices are low. When the supply is short, the prices go high. They instituted a demand curve, and we have had it for the last four demand curve three-year resets.

The demand curve is based on how much we need to procure through our planning criteria, and as the choice of a proxy unit, which is the cost of new entry, which is defined in our tariff to have the characteristics of a peaker. So as a requirement, the peaker is supposed to recover all its fixed costs. The capacity market is designed to provide the missing money to the peaker.

Now of course, there may be units more efficient than the peaker, so they tend to cover the missing money when the market is slightly low. However, the expectation is that there is enough missing money recovery for the market to satisfy its requirements, and the sloped demand curve provides price stability that has worked for us for the last ten years plus.

In terms of market, we do not have a three-year market. We procure from six months. We run a six-month strip auction, we run monthly strip auctions, then we run whatever. The rest of it is geared to what we call the deficiency auctions, the spot auctions which are monthly spot auctions.

The sloping demand curve comes in effect in the monthly spot auctions. The strip auctions, the six-month strip auctions and the one-month strip auctions are matching supply and demand.

The other feature which is important is the New York market allows bilateral contracts and self-supply, so we expect the load-serving entities to procure long-term and give the generating companies who are looking for a long-term financial commitment the ability to do that. Our market allows that. It allows load-serving entities into long-term contracts.

What we've found is that the strip auctions, the spot auctions inform the bilateral price formation, so the idea is to give the price which will allow needed investment contracts to be structured. The other thing is that we have a backstop planning construct to preserve reliability, a planning process -- if we see we have a ten-year look-ahead from the planning, if we have a reliability problem, we have the ability to call for a backstop-regulated solution. So we do not depend on a forward market construct to preserve our reliability. We believe that price formation and price signals are important, and we have the planning backstop construct, which we haven't luckily had to invoke in our history yet.

The other thing which we had to do in our market, and this was through 2006 to 2008, was to put in supply-side and buyer-side mitigation. Supply side prevents suppliers from exerting market power, and on the other side, buyer-side mitigation prevents buyers from applying monopsony power.

What we found is that supply-side mitigation is easier to administer for the ISO. Buyer-side mitigation depends on projecting future prices, costs of building, construction, determination of uneconomic builds. And this has been for the ISO difficult to implement, and has been the source of much litigation in front of you before.

What we found in the last ten years is that our markets work. Our markets have effectuated 10,000 megawatts-plus of generation in the correct location. Eighty percent of these builds have been in southeast New York, where our load is heaviest and the capacity is required. We've had 1500 megawatts-plus of demand response, and 1600 megawatts of transmission, which is high-voltage DC-controllable line type of transmissions, which are essentially capacity injections into our market.

It's interesting that we've also had about 1500 megawatts of retirements. So what happens is that capacity additions are lumpy. When you have a new, efficient unit come in, older inefficient units no longer recover their missing money, and at a point they decide to retire. The fact that you have 10,000 megawatts of new generation but 1500 megawatts of retirement is a sign in our opinion of a healthily-functioning market, because you're preserving your resource adequacy while not overpaying essentially. Because if nothing retired, you would think the markets were too rich. So the fact that we've had retirements, we have additions, and we've preserved our reliability is the sign of a healthy, functioning market.

(Slide.)

MR. MUKERJI: This is the one chart I'd like to refer to. You see the red prices are in New York City, the blue prices are in New York Control Area. Particularly there, capacity is lumpy. We had a 500-megawatt unit, you can move the price $5 to $7 in New York City. The New York Control Area as a whole has three times the capacity, so the effect is less. So the market is lumpy. When there is a new unit, prices drop for a few years. When a unit retires, the prices go back up.

This is a price signal that the market gives, and units come in and retire based on these price signals. But this is just to note that these prices are lumpy. However, the fact that you can have bilateral contracts, we expect generators to have bilateral contracts to get the financing in. But these prices inform the market and inform the prices of these bilateral contracts.

We've considered going to a forward capacity market, and we engaged FTI Consulting to look at that. They did not recommend that we move to that. A couple of the salient points were: when you procure forward, you have a tendency to over-procure, and one of the things that we've seen in our neighboring markets is that resources sell in the forward market and then sell out in the reconfiguration auction at a profit. That means that the prices in the reconfiguration auction are lower than the prices in the forward auction. So that seems to confirm what our consultant did tell us: that you might not be saving costs for consumers by procuring forward. You might want to do that to preserve reliability and preserve adequacy, but you will have a tendency to over-procure.

And they found that our planning backstop mechanism was adequate, and did not advise us to go in the forward market, and recognized the fact that our market allows bilateral long-term contracts to function within our framework.

We have a number of initiatives that we are working on with stakeholders, foremost of which is creation of the new capacity zone. The other thing we're working on is improvement of our scarcity pricing, so we do believe that more of the scarcity pricing is more targeted. We had excellent performance last summer with the improved scarcity pricing, and we had only 1,000 units derated or out of service in the hottest weeks of July.

There's a number of initiatives that we're working on on the buyer side, exemptions to buyer-side mitigation. Because we feel that our buyer-side mitigation rules may be overly restrictive. It says that every unit has to be subject to these evaluations, which has a lot of administrative burden, and there's a lot of burden of proof. So that's why this leads to the litigation.

We feel, for example, if someone is building a merchant generation with no funding from a regulated entity, it should be exempt from buyer-side mitigation. We believe that a unit which is viable can repower without being subject to buyer-side mitigation. When we do the evaluations for buyer-side mitigation, we have essentially a six-year look-ahead. Some investors may have a 40-year look-ahead. So we do not want to second-guess them if they are a pure merchant investment.

So we are looking at, we are working with stakeholders some exemptions from buyer-side mitigation rules. We are also looking at the level of mitigation, and maybe we need to increase it, because units that are truly incompetent with goals, to give exemptions for some units which are truly incompetent when coming in, we should increase the level of the mitigated value.

We are also trying to refine the rules for mothballing and retirements, because they do affect our capacity markets. For example, mothballing units are assumed that they can come back when we do the buyer-side mitigation evaluations. They can be economically mothballed and have no obligation to come back for many years.

So we are working on a slew of market initiatives to look at buyer-side mitigation exemptions. And other ones have been better locational pricing and better scarcity pricing.

Thank you.

MR. DENNIS: Thank you very much. Mr. Ott?

STATEMENT OF ANDY OTT, PJM

MR. OTT: Good morning. Thank you so much for the opportunity to speak on capacity markets.

As Commissioner LaFleur indicated, the absolutely fundamental goal of capacity markets is resource adequacy and reliability, and to insure on a long-term, sustainable basis that we have the resources necessary -- coordinated, of course, with reliable transmission planning -- to insure long-term reliability.

We again appreciate the opportunity to discuss this is a holistic way. The Commission has over many years been supportive of the development of the forward capacity market in PJM through many settlement proceedings, et cetera. Again, we believe it's been a progress well worth the results.

I think we need to look at what we're trying to accomplish as we discuss capacity markets today, what we did accomplish, what we've actually seen, because we have examples of the capacity markets working. I actually tried in my testimony to give you some of the testimony that we had in 2006, because I thought it would be helpful to reflect on what folks had said back then. I'd actually heard some did reflect on what they said in preparation for today, so hopefully that was successful.

Many issues will be raised today. We'll replay some debates from the past. There are many views, all are informed by subsequent events. Even though there are many opposing views, I think there's one fundamental reality. The facts that we've seen, at least in PJM, is that on balance I believe we're much better off with the forward capacity market than we were prior to having it.

Not only, I believe, are capacity markets necessary -- a clear definition of what capacity is, so the folks know what their obligations are -- but also a forward market is absolutely necessary. And we think we've shown, the results in the PJM region have shown, that those are absolutely necessary.

Again, although RPM has been subject to continual review, and there's a lot of tweaking going on as we go through, I think on balance if we look at the major issues we were facing back in the 2005-2006 time frame, where we were having retirements spurred by environmental regs, and we were seeing a decaying resource adequacy mix, we look at what recently happened -- the MATS rule with EPA, and some other more localized environmental regs that are putting stress on the generation fleet -- what we've actually seen is a transformation. I think we're in the middle of a transformation, at least in PJM, of the switching.

Again, as you look at the results, we have 28,000 megawatts of new generation come through the capacity market. We've had 14,000 megawatts with demand response. We've also had 22,000 megawatts of retirement. I mean, this is unprecedented, and I think what we've actually seen is, on balance, the market has withstood it and actually delivered forward resource adequacy.

Again, this forward market has given us essentially confidence that, three years from now, we're going to have adequate resources. They're all locked in. They're contracted. Other regions are facing forward uncertainty, and some other regions are actually resorting to surveys of their members to determine if they have enough resources in the future because they're dealing with such uncertainty. That is not a sustainable construct. They think the forward capacity market requires that kind of obligation.

As we look at the performance, though, are we getting performance from the capacity resources that are committed? Generation performance, demand response performance, performance of alternative technologies that have come in as capacity. All are very high performers when we're actually calling the average call of DR in our market. I think the average response rate is 95 percent when we call it during emergencies. There are times when we get over 100 percent.

Generation response. When we call a generator, is it there when needed? Absolutely. The generation response rates are comparable in the 90s. So we are actually getting performance from these resources that are committed.

Of course we can't be complacent. There are issues we need to deal with. We need to better align some of the operational obligations, especially of demand response. We've actually had some operational situations where the demand response obligations are less than maybe they need to be, so we need to deal with that. We need to recognize some of the operational challenges due to the fairly significant increase in imports into our market. How are we going to deal with that operationally? Do we have the reliability measures in place to make sure that we can actually sustain adequacy as we move forward?

We do address issues related to the interactions of the incremental auctions. We've seen again capacity buyouts. Most of the buyouts are from the shorter-term resources, the demand response and the imports. We've seen a disproportionate amount of folks buying out of their forward physical obligation. We need to deal with that and make sure that that on balance is insuring long-term adequacy.

We also need to review the performance of the demand curve. We have seen some price volatility, not in the entire market, but in parts of our market. Price volatility is harmful if it's extreme to both conventional generation and demand response. I've actually had discussions, if we have a high price one year, somebody sets up their demand response portfolio to ramp up to meet their forward obligations, so they're out seeking customers to sign up. Then the year after that, it falls back down. How do they actually manage acquiring that portfolio when they know it's only for one year?

So, that price volatility is creating not only problems for the generation, but also for demand response, and only in certain areas of the market. We need to make sure that it's working correctly. We'll be reviewing that.

I would be remiss if I didn't go back and talk of capacity, although there's nothing like a good capacity conference to get everybody to come in and say hi to you. But we do need to put it in perspective. Capacity absolutely is important. But we do have an energy market, and the last I checked, a fair amount of revenue goes through the energy market. The energy market does, of course, provide the majority of the revenue in the market for resources.

Obviously recently, the forward energy curves have taken quite a dip, at least in PJM. We saw a 10 percent drop in the forward energy curve, so that obviously is creating some stress out there. But one thing, I think, to answer a bit of Commissioner LaFleur's question: I think it's key. I mean, the capacity market can deal with certain characteristics, I can say enhanced to deal with certain characteristics like minimum standards for operation -- in other words, what obligations and operations are minimum standards for all capacity resources. They can deal with fuel security, certainly, and those types of things are very well suited for a capacity market.

But operational flexibility items, like ramping and synchronized reserve and these other types of things, are much more tailored toward energy market solutions, I think, as others have said. So you have to put it in perspective.

If I go on a little bit -- of course, I'm not going to read my testimony to you. But I do want to highlight a few things. One was the goals. If you actually look at the goals of the PJM capacity construct, the first goal, of course, was to provide a mechanism to insure that we had rational retirement decisions. In other words, we weren't seeing the retirements that were looming because of all the stress on the system to be irrational. In other words, we didn't want retirements to occur when we had inadequate resources. Obviously, it had to be retirements occurring because we have competition and displacement of those resources economically.

So if we look through the history of what's happened since the PJM forward capacity construct was put in, we've had 22,000 megawatts of generation retirements. The generators are either actually retired or they're in the process of retiring. We've had about 1700 megawatts where we had to step in, use a backstop procedure called a reliability must-run contract, for a short period of time to keep on a unit, to upgrade the transmission system to allow it to go. Those have been very fleeting. We've had to occasionally use them.

The measure would be of performance -- is it working? -- not needing that, because the market should provide that. I think that we've had relatively good performance there. Obviously, we're in tune to making sure that those backstop mechanisms remain what they are, which is very seldom used, and I think we've already seen that occur.

If you look at the next goal, we had obviously the need for new infrastructure investment, and those key elements of the forward capacity market that we feel have done that. First is the locational signal. As others have said, this is absolutely critical to have a locational aspect to these capacity markets. The other, as I said, is the three-year forward commitment. That's absolutely vital to make sure that we have -- and again, it doesn't have to be three years, but it needs to be forward. It needs to be a significantly forward look.

I don't believe a forward look overprocures. I think what it does is allows you to manage the uncertainty in the most cost-effective manner, because you do have forward uncertainty. You don't know what the load forecast is going to be. You don't know what the three-year forward situation is going to be. It's better to have a forward construct to manage that uncertainty most cost-effectively, rather than have it surprise people, and then if you guessed wrong, then there's a lot of expense to catch up because your options become more limited. So we would think that's absolutely the best approach.

The last, of course, is this sloped demand curve. That has been an issue. Again, we've had some volatility issues in parts of our market because of externalities. That tends to be in the western part of the market. I think we've had much less of that in the eastern part of the market, which is less susceptible to some of the externalities. So again, I think we've seen that.

The last is, again, RPM, which was to create competition, to open up the capacity construct to other types of resources, to have competition. So one other measure is, did it work? Did we see alternative technologies come in? I've already mentioned the 14,000-megawatt system demand response. It's been unprecedented. I probably talk more about the performance of RPM from that perspective to folks than any other. And I think again, we probably to some extent are a victim of our own success. We have so much demand response which is absolutely performing well, but if I turn to the future, what do we need to deal with?

One of the things is, we have 14,000 megawatts of demand response. 13,000 of it at least all gives us the same notice, two hours' notice, and all gives us the same price and the same emergency obligations. So I now have a block of operational resource that is about 8 or 9 percent of our total resource. It all looks the same. It's homogenous in operations. We can't sustain that. We really need to have more diversity in those resources. We can certainly sustain that level of DR in operations, but it needs to break up.

So, one of the things we're looking at is actually very similar to what we have for generation obligation. The DR response would have to be based on physical capability. So, instead of a contract that says, I'll interrupt in two hours, if a certain site can interrupt in 30 minutes based on technology, another one can do an hour, that's what we're looking for. We're not looking for a major change here. We just need more operational diversity than we can feather in, or do better on dispatch.

Second is the economic side of it. There's certainly got to be a correlation between some of the economic -- excuse me, the emergency actions we take and the energy market shortage pricing. There needs to be interaction there with the operating reserve demand curve we have. Therefore we believe that all resources in the energy market generation currently must give us an economic offer unless they have a reason to be an emergency-only resource. I think we need that same rule for demand response to maintain continuity.

As we look forward, we also need to look again at the imports, to make sure that those operationally can be managed. We can't obviously have an infinite amount of generation come in from outside during operations. We need to have some way to manage that. So that is one of the things we'll be looking forward to in the future.

Lastly, I would mention the issue of the interaction of the base auction, the forward price, with the incremental auctions. Unfortunately, PJM, when it procures in the incremental auction, we're selling back obligation. We as part of our test put that sell back in at zero price, which has collapsed the prices and created an asymmetry in our incremental auctions that we'll have to deal with as we move forward.

I think on balance I'll just leave you with a couple thoughts. We've actually had several different reviews of our capacity market. I think the consultant's message was, it has enabled cost-effective substitution of competition to get capacity at the lowest cost. We've actually seen it allow again efficient and economic response to these environmental rule changes that are occurring. So we believe on balance again, we're much better off, but we need to make sure that we deal with some of our issues of operational performance.

Again, I thank you so much for the opportunity to speak to you, and look forward to questions.

MR. DENNIS: Thank you very much.

Before we turn to Mr. Bowring, there's a second overflow room that's been opened; Hearing Room 6 down the hall is also an overflow room, if you'd like to go there. So hearing rooms 2 and 6.

Mr. Bowring?

STATEMENT OF JOE BOWRING, MONITORING ANALYTICS

MR. BOWRING: Thank you, and thanks for the opportunity to be here to talk to you today at the technical conference.

Capacity markets are in place to address what's called the net revenue issue or the missing money issue. That can actually be addressed using a number of mechanisms. It can and was addressed using cost of service regulation. It could be addressed through bilateral contracts, as it is in some areas. It can be addressed through simply letting people exercise market power. It can be addressed through administrative scarcity pricing, and finally it can be addressed through capacity markets.

My view is that the combination of scarcity pricing and capacity markets is the best way to go. And in fact, doing scarcity pricing better will tend to lighten the load a little on capacity markets, shift more of the revenue from energy markets, provide a better mix of incentives.

Relying to the maximum extent possible on markets, whether they be scarcity markets or capacity markets, you are providing incentives and you are letting investors bear the risk. But also, investors respond creatively to market signals, clearly a reason to rely on markets to the maximum extent possible.

Of course, these are administrative structures. But given the administrative structures, and that applies to scarcity pricing and nearly all the other solutions, the goal within those administrative structures is to rely on market signals as much as possible.

So what's the capacity market? What are the elements of capacity markets? Well, first you have demand, of course. Some economists, like Farben, talk about demand and supply, which is okay, and the economic fundamentals of the market. So on the demand side, there's a must-buy requirement. On the sell side, there's a must-sell.

These markets cannot work, as has been demonstrated, without both of those, without a must-buy and a must-sell; the sooner we get to reveal the underlying price consistent with the fundamentals in the market. Some slope is clearly better than no slope; it does tend to mitigate volatility. But the amount of slope is pretty clearly limited.

When you look at the actual demand curve, the slope is over a very small part of it, and that's for a reason. The downward-sloping part can't really begin before the minimum reliability requirements, and the extent to which it can exceed that is really a matter of judgment. How much extra capacity do you want to secure even when the price is low? The total range there is limited. So, while it's a positive to have a downward-sloped demand curve, we shouldn't exaggerate the positive effects it can have on market outcome.

On the supply side, there is and should be a must-offer requirement. But there are several characteristics of capacity. What is it that customers are buying when they're buying capacity? They're buying something that's physical. It's not liquidated damages contracts. It's not slice of system. It's a physical product. It has to be deliverable to load. Load actually has to be able to get it when it's produced.

As to the energy associated with it, it has to be recallable, because when you're paying for it and you're in an emergency, you want access to that energy, and that energy has to be recallable. And finally, as in the PJM market, you need a must-offer in the energy market.

Capacity markets don't exist by themselves. In fact, the only reason for the capacity market is to make the energy market function better. Ultimately, the goal of all of this is to provide reliable energy at the lowest possible cost -- no lower, but at the lowest possible cost. And that's the reason for a capacity market, not because we like capacity, not because capacity has some particular features, but because it allows the energy market to work.

Forward-looking is another aspect of the market. I agree with what's been said about forward-looking markets. It permits competition. It permits new entry. It permits dealing with uncertainty. In fact, in PJM, it's demonstrated to successfully address adjustments to environmental regulations, or very substantial adjustments to environmental regulations, and also permits competition to replace retiring resources.

The market in PJM is appropriately locational. The capacity market prices must reflect the underlying realities of the transmission system. I think, in fact, the PJM market needs to get more sophisticated than it is right now. LDAs reflect the old-fashioned transmission zones, which are a good place to start, but don't reflect the electric reality at all times.

Market power rules are essential. Both supplier-side market power rules, which in PJM have been working very well, as well as buyer-side market power rules. Buyer-side market power rules in PJM are still work in progress, but they're substantially better than they were only a year or so ago.

What are the metrics of success? The first and most obvious, as has been mentioned, is maintaining adequate capacity. If you have maintained adequate capacity to meet reliability, you've passed the fundamental test of a capacity market. But a second test, as I indicated, is to insure that you're providing capacity and energy at the lowest possible combined cost.

Another metric for success is whether capacity market prices reflect the underlying economic fundamentals. That really is the key to getting reliability at the lowest cost. In my view, the PJM market has not always done that, and I'll explain some of the areas where I think that has not occurred.

Some of the issues and challenges facing the PJM market. On the demand side, clearly the markets work well when demand is fully reflected in price. But in PJM there is, as I've been talking about for some time, a 2 1/2 percent offset to demand. Clearly, if you simply artificially reduce demand, that's going to change price. In fact, that's had a very substantial impact on price in the PJM market. This is not trivial at all; about a 20 percent or so reduction in revenues in the PJM market in, for example, '15-'16, and the results have been consistent across the base residual auctions.

On the supply side, markets work best when the product is clearly defined, when it's as homogenous a product as possible, and all supply has those same basic features. It doesn't mean there are no variations in product; there's lots of different types of generation and lots of different types of DRs, and lots of different types of resources that can be capacity. But it does mean that all of the capacity sides have to have core attributes.

As a general matter, again to agree with some of the things so far this morning, it does not make sense, in my view, to subdivide the capacity market by operational characteristics. Those are best dealt with in the energy markets.

In PJM, another issue is that the limited DR and the unlimited DR products actually don't meet the product definition tests. In my view, again, and I've said this more than once, those products are inferior in that they only have a very limited obligation to respond, only a very limited obligation to provide energy. They don't fit as well as other capacity products in the energy market design.

So, the result of letting those products replace generation with an 8760 obligation is that the price is suppressed, compared to an efficient price.

Another point about demand side, and I think Andy said something like this, is that it's being cleared in the market. It's being cleared like other capacity, and should be treated as an economic resource. It's not an emergency resource. It's an economic resource, just like the rest of capacity. We have to figure out a way to try to make sure it's treated that way.

A key attribute of supply is that it's physical. In PJM, that requirement has to be enforced, and I think there's some areas where that needs to be improved.

We've done and published and sent to you all a fairly detailed report on the replacement of capacity obligations between base residual auctions and incremental auctions. If you're making speculative offers in the base residual auctions, because you've certainty of a lower price, then the option to buy that out in an incremental auction is not consistent with the underlying fundamental physical feature of capacity. That should be part of the initial obligation.

So, demand side buys out to a larger extent than any other resource type. But it's not the only one that buys out, and part of the solution is to enforce the existing tariff requirements that those resources be identified, have customers identified, and be physically identified before they can offer the BRA.

But imports also buy out of base residual positions. Imports should also be required to have the same evidence of physical transmission capability, firm physical transmission capability comparable to internal generation and comparable to DR, again to prevent speculative and forward offers, and we have seen some of those.

Again, PJM should enforce an overall simultaneous import capability to insure that PJM is not relying on external resources without the same -- that do not have the same characteristics that internals do. Speculative imports, and we've given you these results before, did have a very suppressive impact in the '16-'17 auction, and we know that about 6- to 7,000 megawatts of additional transmission requests are in the queue now. So it's critical that PJM and the PJM rules address this issue before the next BRA.

Internal planned resources also buy out of their positions. So this is not -- when I talk about buying out of positions, I'm not picking on DRs. A number of different resource types do that. Internal planned resources do it as well, and again the point is to try to insure that internal resources and planned resources are physical and provide assurances that they actually will be provided.

A couple of other areas that need strengthening in PJM, in the PJM markets in my view -- performance incentives. This has been said, and I agree: performance incentives in the capacity markets should look as much like the performance incentives in an all-energy market as possible. Right now, that's not the way they look in PJM. You can get 50 percent of the price in the auction if you don't do anything, and there are issues with the definition of outages, which affect the amount of capacity you can sell.

In conclusion, so I don't go past my ten minutes, capacity markets in PJM have absolutely worked well, as Andy said. They have shown their promise. All the key elements of the capacity markets exist, and there is absolutely no question that PJM markets are better off as a result of the RPM design than they were under the old -- I can't say an acronym, either; I don't even know what it was called -- anyway, the prior daily design.

(Laughter.)

MR. BOWRING: I can't speak without acronyms. It's not possible. Clearly it's an advance over the prior market design. What we need to insure, and it seems simple but it's actually hard to do when you work through the details -- we need to insure that market fundamentals are revealed in the prices without distortion. That gives you the right incentive for investment, the right incentive for retirements. It allows the capacity market in its flexibility to deal with the demand side, to deal with RPOs -- which I actually think it does very well -- to deal with alternative resource types.

The alternative is that you get market distortions. Those market distortions tend to lead to ad hoc solutions, which then sort of have a spiral downwards. You have to step back and make sure the fundamentals are right, not try to tweak things to try to solve problems one off, but to make sure the market fundamentals are right.

Thank you very much.

MR. DENNIS: Thank you, Mr. Bowring. Mr. Patton?

STATEMENT OF DAVID PATTON, POTOMAC ECONOMICS

MR. PATTON: Good morning. I really appreciate your having this conference. I think there is no more set of complicated issues than the issues the RTOs are facing, and trying to construct markets that efficiently facilitate investments and retirements and maintenance, and all the decisions that are facilitated by the economic signals in these markets.

One important threshold question that I think is important the Commission recognize those questions have not been answered is, should the ISO markets be designed to facilitate efficient private investment. That is not an objective that every RTO has answered yes to. I think the three up here have. But I think it's important to recognize that even something as simple as specifying that sort of basic, fundamental principle that all markets should adhere to is something that hasn't been done.

What I'm going to try to do, because this is so complicated, I'm going to try to step back and sketch out the elephant, and where the disconnects are, and sort of the approaches different RTOs are taking.

(Slide.)

On slide 1, we talk about missing money. You hear about missing money a lot. The three sources of revenues that a private investor, going back to the threshold question, that a private investor is going to look at to decide whether to invest, is the net revenue from the energy market during shortages, the net revenue during nonshortages -- which tends to be relatively low except for base load units -- and capacity market revenues. Some combination of those three revenue streams has to produce enough revenue for an investment to break even, if you want the private investor to invest.

So you're basically making choices when you design these markets, of how much of the revenue is going to be in the capacity market, and how much of the revenue is going to be in the energy market. In theory -- go ahead to the next slide.

(Slide.)

In theory, the energy market could entirely provide the incentive. The problem with that is, you'll get probably somewhere in the range of 8 to 10 percent planning reserve margin, and we don't set planning reserve margins at 8 to 10 percent in any of these regions. Generally, they're in the 14- to 17 percent range, which creates a missing money problem.

What are we saying when we say, missing money? The reason an energy market doesn't get you there is because, if you price energy at what it's really worth to consumers when you can't provide it, which I'll refer to as the value of lost load and avoid referring to it as VOLL -- the value of lost load may be somewhere in the range of $5,000 to $30,000 a megawatt hour, depending on what type of consumer you are. Commercial and industrial consumers generally value electricity more than residential.

The one day in ten year planning standard probably implies a value of lost load somewhere in the $100-m to $200,000 a megawatt hour range. We don't spend a lot of time scrutinizing whether that standard makes sense. We've just sort of adopted it. But ultimately, what it means is, we have to find a way to generate revenue, much more revenue than an energy market that just prices on the value of lost load would generate in order to meet these planning standards.

You basically have two choices, not very complicated. You can rev up the energy shortage price to a level that's way above what consumers value electricity for, to try to create more revenue coming out of shortage pricing. Or you can have a capacity market. I think generally what you're hearing from most folks is, some combination of those two makes sense.

Go to the next slide.

(Slide.)

I tried to put in perspective some of the attributes of capacity markets, and where the three RTOs up here stand on these. I would say there are three essential attributes of a well-functioning capacity market. Number one by far is the sloped demand curve -- well, actually, let me not say, by far. Having locational requirements is a close second, and having effective mitigation measures is a third.

So I put check marks where I think RTOs have accomplished that objective. I put nominally a half of a eheck mark where there's still development underway, and there may be some degree of struggle to try to effectively meet that objective. And then, I would put in the optional category forward procurement, and I can talk about why that's not nearly as important as the first three if I have time.

Go ahead to the next.

(Slide.)

Vertical demand curve. This is an extremely damaging aspect of capacity markets. We talk a lot about administrative aspects of these markets, but you have to recognize that, because demand is not fully participating, at this point the provision of reliability has to be administrative. We have to be procuring reliability on behalf of consumers.

So virtually everything on the demand side is administrative. How much reserves we procure in real time is administrative. What value we put on the reserves, which determines how high the energy price will be when we can't procure enough reserves, is administrative. The requirement for capacity is administrative, and how we represent the demand.

But as an economist, you can expect that if you construct a funny-looking demand for a service, a demand that doesn't reflect the underlying value for the service, you're going to get funny outcomes. My wife sends me to the store to buy apples. I would be an odd consumer if I walked in willing to pay -- normally she likes something like seven apples. I'd be willing to pay $100 for the seventh apple, but if they're having a sale and they're going to give me eight, nine and ten for a nickel, I say, no. My wife wants seven. You can't get a well-functioning market like that.

So what we're saying is, a vertical demand curve is the last megawatt you need that can meet your minimum requirements, usually multiples of what it cost to build a unit. And the first additional megawatt after that is worth nothing on the demand side. What that leads to generally is prices that are sustained at close to zero, because in most RTOs they have planning processes that will prevent you from going into a shortage.

Go ahead to the next slide.

(Slide.)

A sloped demand curve, on the other hand, reflects the fact that as you add capacity above the minimum requirements, the probability of curtailing load goes down, and there's value in not curtailing load -- the value of lost load times the probability of curtailing load. And if you calculate how that probability goes down as you add more capacity above the minimum requirement, you'll get something that looks like a sloped demand curve.

The value of this is that the capacity levels are always going to fluctuate in these markets. And the first, most important thing a capacity market can do is provide a transparent, efficient price signal that allows people to contract forward and make long-term decisions. You don't have to set that price signal three years ahead, but the price signal has to be understandable. People have to be able to forecast it, and if they can, they can forecast retirements and additions and look out and have some confidence in the integrity of that market. Then they can start signing contracts to build new generators in the bilateral market, or make decisions themselves to build.

Go ahead to the next slide.

(Slide.)

These are the other two. I'll just touch on them quickly. Locational requirements are extremely important. What we're finding in a lot of these markets is, some of the most important planning requirements now are transmission security requirements, which basically means: if I don't have enough capacity in an area that contingencies can cause my transmission system to become insecure, and result in cascading outages. So I have to make sure that where my load is located, I have enough capacity on line that I'm able to suffer a large contingency and get the system back in a reasonable amount of time, so that I'm not at risk of another contingency happening and having the transmission system go out.

I think this is the one area where I generally think -- the New York market functions well, and has achieved the objectives that are set out for the capacity market. But this is one area where they really do need to work on this. It's a monumental struggle in New York to reflect new locational requirements, as witnessed by the new zone we've been recommending for six years -- I lose count.

The problem is that these transmission security issues are somewhat dynamic. If your market is not dynamic enough to reflect them, then you're not going to be able to allow prices to adjust to meet those requirements. I think PJM's pre-definition of zones and ISO New England is one way of getting at that. The fact that you create a zone doesn't mean you're necessarily going to get high prices there. That zone may not bind, and so the prices would be the same in and out of the zone. But, having it defined so that when you do have a problem, price is immediately reflected, is extremely important.

Lastly, it's critical to address market power. In almost every narrow area you have a pivotal supplier, which means you can't meet your requirement without that supplier. You have to mitigate that form of market power.

It's also important to address subsidized investment that's intended to result in artificial suppression of capacity prices. That does lower costs for consumers in the short term, but in the long term it raises costs, because the retail customers are saddled with this uneconomic investment over the life of the investment. So in the long term, it's very bad strategy.

Lastly, I'll just hit forward procurement quickly. It's important -- I think there's a problem sometimes that I run into in talking to people in this industry, and that is they have this notion that if the ISO does not run the market, the market doesn't exist. So if people say things like, "I need to be able to lock in revenue in order to build a unit, and I need to be able to lock that in three years in advance, four years in advance," sometimes there's the notion that, "Well, the ISO needs to facilitate that market."

Well, there actually is a forward bilateral market, and the kind of lock-in most investors are looking for is lock-in of five, ten, fifteen years' worth of revenue. So they want a contract. The important thing for the RTO to do is to facilitate markets, or to have markets that will facilitate that efficient contracting process. And the RTO markets that do that don't have to be procured three years in advance.

I think there are some potential benefits and drawbacks to forward markets, and I think it's useful that we're doing both. I think it's premature to determine that one is the right answer. So I think it's a great opportunity to collect data, compare performance and make a decision in the future about how valuable forward procurement is.

Operational characteristics -- back to this energy versus capacity issue -- good energy pricing will facilitate the kind of behavior that you want. If you want me to put in something other than gas because you're worried about gas contingencies, then price shortages efficiently, so that when we have gas contingencies and we lose a bunch of gas generators and there's a shortage, people who have dual-fuel capability are going to make a huge amount of money, because they're going to be able to run and make the multi-thousand-dollar prices.

Same thing with operational flexibility. Units that can get on quickly can take advantage of unforeseen shortages, where units that take eight hours or 12 hours to start will not. So the first thing that I think is important to do, in terms of resource characteristics, is really get the energy pricing right. Price energy at the full value of what it's worth when we're in shortage. That will motivate a lot of the sort of resource characteristics you're looking for.

Then, to the extent that that doesn't get you what you want, usually you can figure out why. Beneficial environmental attributes are not priced in these markets. That's a reason why you might not get as much investment in environmentally-friendly technologies. Then you can take steps to really target those areas rather than generally requiring more flexibility or attributes that should be motivated by the markets.

The last thing I would leave you with is, because people are making decisions over 30 years, debility is critically important. One of the worst things we can do in these markets is continually revisit and redesign, because it causes investors to have to put a huge risk premium on any revenues they think they're going to get from the capacity markets. So whatever we can do to sort of incrementally evolve these markets, and not create the risk of significant changes, I think is definitely valuable.

MR. DENNIS: Thank you, Mr. Patton. Thank you, everyone.

Just a reminder that there is an additional hearing room open for overflow for folks who just joined us, Hearing Room 6, as well as Hearing Room 2.

Let me turn to the Commissioners for questions, beginning with the Chairman.

CHAIRMAN WELLINGHOFF: Okay, thank you, Jeff. I appreciate it.

Several things I'd like you to consider. I want to ask questions of the three RTO representatives. In this country, new distributed solar PD systems are going in one every four minutes. The increase in self-generation, in whole or in part, by commercial or industrial customers has increased from about 10,000 over a number of years ago to 40,000.

The question I have for you is, first of all -- well, let's start with this question. Distributed solar PD -- is it something that can be bid into your capacity markets? If each one of you could give me the answer to that.

MR. ETHIER: Currently, what we're seeing in New England is a lot of solar PD happening behind the meter.

CHAIRMAN WELLINGHOFF: That's what I mean by distributed solar PD.

MR. ETHIER: Right. Those resources simply don't participate in our capacity market. They are included in our planning calculations, so we see that decreased load going out into the future, and we buy less capacity as a result. But to date that's how they've operated.

CHAIRMAN WELLINGHOFF: Before the other two answer on that one, tell me how you incorporate that into your planning criteria. I just wanted to follow up on this.

MR. ETHIER: Sure. We actually over the last couple years have developed a methodology for including energy efficiency expenditures by the utilities, which has been substantial in New England, as part of our load forecast methodology. We are looking to replicate that for distributed solar so that we would see the amount that's going to be spent on solar, and it's pretty much going through the utilities these days. And we would incorporate that into our load forecasting in the same way that we do for EE expenditures. For every dollar that's expended, you know, there's a kilowatt reduction that we assume.

CHAIRMAN WELLINGHOFF: They can't bid into your market, then?

MR. ETHIER: Currently they choose not to. Certainly they are able to if they meet their minimum threshold size. They just choose not to.

CHAIRMAN WELLINGHOFF: Rana?

MR. MUKERJI: We have one large-scale solar, which is about 30 megawatts, on Long Island.

CHAIRMAN WELLINGHOFF: Again, I'm talking about behind the meter.

MR. MUKERJI: Behind the meter we adjust the load forecast. The other thing is, if the solar can aggregate to 100 kW, and if they have solar with battery,if they can form it up, if they can aggregate the 100 kW, they can participate in the capacity markets.

CHAIRMAN WELLINGHOFF: Andy?

MR. OTT: Yes. It would come in as a forward DR.

CHAIRMAN WELLINGHOFF: So how do you account for other types of self-generation: combined heat and power, microturbines, fuel cells. How is that accounted for in your capacity market? Andy?

MR. OTT: Well, again, it would depend on the size. If it's behind the meter, it could come in as a DR resource effectively. Again, it depends on what type it is and how it's integrated. If it looks like an energy efficiency resource, we probably could do that, too.

That's the first option. The second option, if it's larger and is larger than a typical behind-the-meter would be, then it would come in as a capacity resource on a forward basis. Either one would work. The behind the meter rule, certain rules would prohibit, after it got to a certain size it would have to come out and show us that it was not behind the meter.

MR. MUKERJI: Again, if they can aggregate to 100 kW, they can offer into our capacity market. The question is, if you are a distributed energy resource, and you're running flat out, we don't allow that to participate in our market. They have to have the ability to respond to the operator instructions.

We know that this is a growing phenomenon, so we have scheduled a workshop with stakeholders in December of this year, which is because we want to know how this -- a lot of the time, we don't have visibility of what's coming behind the meter. So we want to learn more. We want to devise market rules to accommodate this growing phenomenon. So we have scheduled a workshop in the NYISO on December 13 to do that, and we will develop market rules to better integrate this grid.

CHAIRMAN WELLINGHOFF: Thank you.

MR. ETHIER: Unlike PJM, to the extent that resources want to stay in the market, they would come in through our DR rules. If they choose just to have the load reduction flow through, they have that option as well.

CHAIRMAN WELLINGHOFF: I had one question for David.

You talked about -- it mentions there's an experiment going on. We have PJM with the forward procurement, and New York does not have forward procurement per se. You said that if the RTO can facilitate these bilateral markets, then you may not need forward procurement. Could you explain what needs to be done to facilitate the bilateral exchanges?

MR. PATTON: Yes. Just in general, the way most commodity markets work is, you have a spot market that is physical, and there's price there. The forward markets are entirely voluntary. So people engage in a variety of forward contracting, based largely on the volatility of the spot price and the expectation of what the spot price is going to be in the future. So therefore, gas markets and oil markets and so forth.

The kind of forward procurement we're talking about is not a typical forward market. What we're essentially doing by requiring procurement three years ahead is sort of moving the spot market three years out. And whether you do that or don't do that, I think the most important thing that you can do is set an efficient price that represents the true supply and demand in that market, even if it's month-ahead. Because what happens in New York, where it's month-ahead, is you see the price, you can forecast the price. It facilitates forward capacity prices for people who bilaterally contract, just like energy.

So an investor can go out and sign forward contracts for any combination of capacity and energy that it wishes. The one thing that would undermine that ability to forward contract to support an investment or support the decision to retire -- the thing that would undermine that is not having a sufficient price in that spot capacity market.

CHAIRMAN WELLINGHOFF: Andy, did you have a follow-up to that?

MR. OTT: Key point, Mr. Chairman. In other words, RPM is a forward construct, but it's a 100-percent requirement -- or a 97.5 percent requirement -- and the key is, as we establish that forward call it spot market, if you will, if I may coin a term there, so that you'd have competition come in from new entry, so it's actually a pure price formation.

In other words, it's basically a 100-percent procurement far forward enough so you have competition from a variety of resources, DR, new generation, et cetera, and that establishes a very efficient price. RPM was never intended to be the only revenue stream.

Of course, then you have forward markets develop. But the reason for the commitment is so important. The price formation is much more robust, and that's the key. Obviously, having bilaterals develop outside is wonderful, and certainly would facilitate that. But I just wanted to make that point. Thank you.

CHAIRMAN WELLINGHOFF: All right, thank you. Thank you, Jeff.

MR. DENNIS: Thank you. Commissioner Norris?

COMMISSIONER NORRIS: Did you give your response yet?

MR. BOWRING: Oh, I'm sorry.

I wanted to sort of explain why I think the jury may be out. The one thing that a forward market does that a monthly market does not do is, it allows people, new suppliers, to offer. And if they clear, then presumably they have an obligation to build or they have to buy out of their obligation.

So in theory, what we would like is, if I'm building a 30-year asset, and three-year-ahead procurement is going to give me one year's capacity revenue, I'd like to see new entrants offer at sort of a levelized cost. So if I think CONE is $100 a kilowatt year, if they come in offering $1000 a kilowatt year and we set the price, that's not beneficial.

And so, that's where I think it's not yet clear whether that very short duration procurement forward is really a benefit, as opposed to just allowing investors to make decisions based on what their expectations are over 30 years.

MR. DENNIS: Commissioner Norris.

COMMISSIONER NORRIS: Thank you all.

Let me start with Joe, if I can. This is probably Joe and David on this question. The rest of you can surely fill in.

Joe, you mentioned that the buyer side rules now are better than they were, at least since 2006. Both you and David stressed the combination of scarcity, on the energy-side pricing, and a capacity market to fill in the hole.

So related to that question about the buyer-side rules have gotten in your opinion better -- have we reached a point where there's adequate protection from buyer-side mitigation, yet you also honor or allow entities that have multiple reasons for wanting to self-supply their own energy, or states that want to meet certain policy goals, that we can balance those two? Or are we going to be forced to choose between, if you will, let me characterize -- the pure capacity market model that you want to have, which is mandatory, versus enabling entities to make their own choices to self-supply, or other important policy goals?

Have we reached that, or how are we going to reach that? Is there an equilibrium there, I guess is my point? Can we coexist with those two goals?

MR. BOWRING: I think in PJM we're very close to getting to where you suggest we want to be. The first thing that was done, as far as improvement, was to simply give a blanket exemption to anyone who can demonstrate that there are competitive projects, that there are merchant projects. That's one key thing that saves time and effort.

Once you've verified that, then if somebody wants to risk their money, that's fine. You know, I'm not worried about what they're going to offer.

The second broad exemption was for self-supply. I actually think it went too far in permitting self-supply from vertically-integrated utilities. I think it's critical to keep the paradigm separate. If you're vertically integrated and have cost-of-service regulation-based rates to look over your capacity costs, you should remain either an FR -- you should remain an FR entity. You should not be permitted to compete, effectively subsidize, with those who are not subsidized.

Apart from that, I do think the rules are significantly better. One area where they still need to be improved is for the review of state-specific projects, state-subsidized projects. We don't yet have in the rules that it says we have to use basically the same assumptions we used in the net-CONE calculation. But you just make the view clean. It would make sure that you're not making the project look better by assumption. I think that is one area that the MOPR rules need cleaning up, and the PJM membership is in the process of addressing those issues.

In terms of addressing state initiatives, one of the questions that came up is about RPS. Right now, RPS interacts very well, I think, with capacity markets. RPS is not in the capacity markets. It affects the price. It affects the amount of capacity people buy. It affects energy prices.

Let's just say, there are a number of different RPS standards across the PJM footprint. But let's say we went to a 50, 60, 70 percent renewable requirement. That would clearly tend to depress energy market prices. But that's part of the beauty of the way the capacity markets and energy markets interact. if that happens, then the capacity market prices, because they're reflected in that revenue offset, will go up, and the units that are needed for reliability when the renewable resources aren't there would get the money they need in order to be sustainable.

So the one area that was key to the initial MOPR debate about states subsidizing particular kinds of units to take the place of a combined cycle in a particular town, those are not under the current rules permitted unless they can demonstrate that the offer is actually consistent with a competitive offer. And again, I think that makes sense.

So all of the states' options about renewable resources and other options that are there, with the exception of the option to simply build a subsidized unit -- again, those, just like with vertically-integrated utilities, those paradigms really can't work together. I mean, we've demonstrated and others have demonstrated you have a very suppressive effect on the price for everybody else when you do that.

COMMISSIONER NORRIS: Before you go, David, the FRRs aren't used much. Are they not practical to use?

MR. BOWRING: No, I think they are practical. When the market started off, AEP was an FR entity, and some other entities have used that option. There's no reason that it couldn't be used now. FE used it when they first joined the market.

There's absolutely no reason that a vertically-integrated utility that wants to proceed with cost-of-service-based rates for capacity couldn't be an FRR. I think it's very doable.

COMMISSIONER NORRIS: David?

MR. PATTON: This is a complicated area, much more complicated than I anticipated when I first advocated that we needed something because there was a number of initiatives in New York that had the stated goal of overbuilding and bringing prices down in New York City. So I think we're still in the process in New York of clarifying the rules. It's only been applied to a few projects, and every time it's been applied there's been significant learning about ways in which the rules are not ideal.

I think the three -- and I'm going to be producing a report for the ISO identifying a series of changes that I think are important to get it to really function well -- but some of the important areas that still need work in New York is the offer floor for someone who's clearly uneconomic is too low, so that they still have the ability to depress prices. And we really need the kind of competitive exemption that Joe was talking about.

If someone's just a merchant, the only concern is subsidized investment. I don't believe that I've ever seen a private party that would build uneconomically to lower prices that's so big, so dominant, such a monopolist. That's a costly strategy over the long term. It only benefits you in the short term.

But competitive exemption would be great. And then there's a variety of cleanups in terms of how we conduct our various tests and apply them. Unfortunately, there's so much economic value wrapped around these issues that it's difficult to get anything out of the stakeholder process. Like the competitive exemption is sitting there. I think it's critical. I give it almost no chance of getting a positive vote, and in New York, you probably know they can't file anything that hasn't made it out of the stakeholder process unless they claim exigent circumstances.

So, you know, some of these problems are pretty difficult to fix. Maybe the market flaw referral process is something that would allow the Commission to help, you know, fix some of them.

COMMISSIONER NORRIS: To follow up on that, you said that you should design these markets as a signal for investment. But if you have an entity who has different priorities or needs they're trying to serve -- are you saying just for private investors? Or how about those vertically-integrated or publicly-owned entities that have different goals with their investment decisions? Can those coexist?

MR. PATTON: I actually don't think there's as big a disconnect as some people think. It's rare that regulated entities don't care about costs. It's rare that they would have an ambition to invest uneconomically. I think where there is some disconnect is on some of these areas that aren't priced. I may want renewables for one reason or another, to improve environmental quality. Those are things that are actually legitimate, and if that's what's motivating the investments and those benefits are significant, then really they're not uneconomic, and they shouldn't be mitigated under these provisions.

We don't yet have a way of folding that into the evaluation. And the thing with renewables, too, is they're so expensive that if all I wanted to do was lower prices in an area, that would probably be the last thing I'd build.

COMMISSIONER NORRIS: Anything else on this?

MR. OTT: Just to quickly answer: I think Joe's right. I think on the minimum offered price on the buyer's side, I think we're very close. I think they can coexist, the two models. I think the competitive entry is actually a huge breakthrough, because it took the review of every resource coming into the market away. It's a very quick review now to say, is there any revenue that we're worried about that is being subsidized -- down to a very narrow issue.

So I don't think you'll see that erupt into a major debate in the market anymore. I think the issue of the self-supply, we're in a good spot. I think it will coexist within the market.

COMMISSIONER NORRIS: Second topic -- a lot of commentors, not just you, but a lot of commentors at today's conference argue that now that you have certain proxy technologies, you're encouraging only development of a particular technology. Should capacity markets have a role in encouraging new and emerging technologies? Does the three-year construct favor low-capital, quick-installation solutions like gas?

How do we address that issue?

MR. OTT: I'll start.

The breakthrough I think we had again in the market as part of the rollout of the market, of course, locational aspect and the three-year forward procurement. What that did was set up, not only for new generation -- even existing generation was looking at financing an upgrade -- but demand response or any other type of alternative technology. They could actually go out and say, okay, I'm going to have revenue forward and get financing, so they could actually finance new types of technology to provide more reliable demand response, or whatever. We've seen many examples; I won't go through them here. I certainly can get those to you, where they had deployed technology to actually reduce the burden on customers to actually curtail going to emergency.

So they deployed automation. And then they paid for that through the capacity markets. So the capacity markets across the board, I think, in PJM actually -- you've seen the result of that innovation coming back, because people can now actually spend the money, because they've got a forward revenue stream.

As far as the different types of resources coming in, in my testimony I put in a variety of types of resources that are coming into the market. Obviously right now it's very dominated by gas, because gas is so cheap. But I don't think the construct of the capacity is discriminating against anybody else. It's just the fact that the market conditions are that way.

So I do believe we are seeing innovation across the board because of the competition.

MR. ETHIER: I would say that certainly in New England, we don't feel that the capacity market should have a direct role in influencing the type of investments or targeting certain innovations. I do think there are, however, a couple of things to consider. One is, of course, we don't want any barriers to entry, so we don't want our rules to unnecessarily prohibit someone from entering the market, as long as they can provide us the service we want. To the extent that a new technology comes forward, we need to as quickly as possible address any deficiencies we see there.

The other thing is, it's important that the capacity markets reward the right behavior. And by right behavior, I mean behavior that's needed to run the system well. Actually, I think you incorporate those sorts of characteristics and intentions in the market, you're actually going to incent this innovative technology. You're going to incent those new, flexible resources -- and by new, I mean new types of resources -- because you're actually sending those price signals.

So, I don't think it's an explicit -- the explicit purpose of including those incentives is not to drive specific technologies. Rather, if you get those right, you're naturally going to have that happen.

MR. MUKERJI: The capacity market is not structured to exclude any resources. Our tariff says that you set the proxy units based on the peaker, which is the lowest capital cost, highest variable cost. That means that that's the cheapest increment of capacity you can build.

If you had a combined cycle unit, for example, it would have more energy revenues. We could actually come under it. It doesn't preclude -- you know, that's what demand response usually comes under, under that peaker. New technologies can usually -- they have to do the tradeoff between fixed costs and variable costs.

Now, we had a market rule proposed which was, instead of the characteristics of a peaker, use the most efficient unit, and the jury's still out on that because we did not get the stakeholder vote on that. David recommends that.

But one of the things that we have -- if you base the proxy price based on the peaker, hybrid technologies can do that tradeoff between supply and between fixed costs and variable costs. The market doesn't preclude other types of new innovations to come in.

MR. BOWRING: Just very quickly, if you get the price set right -- and I'm not quite sure exactly what the criticism intended to say, whether it intended to say the price was too low. I think the capacity market prices are probably too low for other reasons.

But you get the price right and you define the product properly, then there's no issue. In fact, it does incent, that structure does incent creative investors to invest in any technology that can provide at that price and meet those standards. I think it has been doing that.

MR. DENNIS: Thank you. Commissioner LaFleur.

COMMISSIONER LA FLEUR: Thank you.

Thank you all for your comments. I think you really did a good job to set the stage for the whole day.

I want to start with reliability. When you all went into your markets, you were very long on capacity. So you would expect the markets to clear at a low price when you were long on capacity and had been for a very long time.

I guess my question is: in that environment, and I want to start with Bob in New England, how can you assure yourself -- what can you look at to make sure that the price formation will occur when new capacity is needed to incent steel in the ground when it's needed? Should you be expecting the capacity market to clear, over the long run, cost of new entry? Or are there other benchmarks that you look at?

I mean, you hear people all the time say, the capacity markets are too low because they're clearing at the floor; therefore, they're not doing their job. But maybe that's right, because there's so much extra capacity. But how will you be able to tell when they should kick in? How do you measure that price formation and whether it's really working?

Just an easy question.

(Laughter.)

MR. ETHIER: Yeah, two minutes or less.

A couple of, I guess, sorts of angles on that one. First, we have effectively hidden sort of the true market outcomes in New England for a number of years because of the price floor. We've prevented almost certainly units from retiring that would have driven us to need new units. So we actually, for the most part in New England, haven't experienced a circumstance where we need new units, with one exception, which is most recently in the Boston load zone. We were short of resources and we actually got a new resource to come forward.

That's the best evidence we have that, A, the markets will get us the reliability that we want when new units, new entry is needed. The price went to apparently new entry levels. I think one of the issues that we saw there, though, was the dramatic shift from price floor, price floor, price floor, new entry levels. That's a function of our vertical demand curve that we talked about.

I think a better construct would be a sloped demand curve where you actually could walk up the demand curve and you'd get incrementally higher prices over the years as the area gets tighter and tighter. That actually better signals the need for new resources.

So one of the lesson learned, I think, from that experience is, boy, a sloped demand curve sends valuable price signals when you're actually short of capacity, because it puts you on the right trajectory to signalling, yes, we need new capacity.

Hopefully, that's an answer to your question. On the longer run, I don't think we have the data yet, because we've been long since the start of the market. So for us, it's hard to look at experience and say, you know, we know exactly what we're going to see over a long period of time, because we haven't lived through that yet.

MR. MUKERJI: The market is designed to be at criteria. The planning criteria, we say we need 15 percent or 17 percent of installed reserve. When we designed the demand curve, we say it's one plant more than that criteria.

So the market is designed to be near the operating point. So my opinion is that, long-term, the price should be around CONE when you have an addition, it should go down when a retirement comes up. But long-term, it will be near CONE.

As you said, we started the markets when there was much excess capacity. But if the long-term vision is that the markets are designed to be around CONE, we are trending to that. Now I can tell you that system operators like to have more than just 17 percent. But you have to start operating at that requirement, because that's what the markets are designed for. We cannot expect that the markets will have well above requirements in the long run. We could have it for short terms when lumpy investments come in.

Sam and David said 7 percent is what you need, bare minimum. Operators are used to running at a 20 percent system. But it does go to 17, they do have some qualms, especially hot days or terribly cold days.

COMMISSIONER LA FLEUR: So you're saying, you're seeing the price formation start to trend to CONE, which makes you believe logically that it will meet the reliability needs?

MR. MUKERJI: That's correct.

COMMISSIONER LA FLEUR: Andy?

MR. OTT: I think our market has actually experienced -- it's not been long everywhere. I think the market is larger and more diverse. Certain areas of our market have had shortages. We've had prices -- I'm sure folks out there who've been affected by them can explain. So we have actually seen the price formation incent behaviors which are responsive to the locational signals.

So the characteristics of the market -- we have actually seen the price formation follow an investment. And if you look at where investment's occurring, obviously it's not exclusively in the high-price areas. But generally it's trending there.

I think the one thing we've seen, as I indicated, was the price volatility issue. The price is high one year, low the next. And again, high-low is in someone's vision or reality, and I think probably the area of the market I would say is most susceptible is the western side of our market. There's externalities there. I don't want to talk about other regions, but frankly, you've got another region out there with an inadequate construct right now.

(Laughter.)

MR. OTT: So the point is --

COMMISSIONER LA FLEUR: We're not talking about it.

(Laughter.)

MR. OTT: I mean, the fact is, we've got to make sure that that doesn't create a situation where we're having a lack of investment in reliability. In a nutshell, I think we have actually seen over the evolution of this market, I think, the proper investment response. I won't go through my testimony, but I think we've actually seen that.

Whether it actually settles out at net CONE I think is key. Because net CONE says, there's a certain return on investment. Somebody may come in and say, I can live with less than that. So it may settle out a little bit less than that because it's competitive, and we may see over time a new technology comes in. In fact, a new gas-fired combined cycle -- high-efficiency gas-fired combined cycles are coming in at much lower investment costs. So we may see that actually would come in and compete away, so it would settle a little bit below what our reference was.

But that's competition. That's what we'll see, and I think over time we have seen that. I hope that helps.

COMMISSIONER LA FLEUR: And so your point, you think a forward spot price is enough to incent the investments? I mean, I think New England holds the price for a certain number of years once the new capacity clears, but I think PJM doesn't.

MR. OTT: I do believe it is, but the market has to have confidence in the price, and that's the key. What I talked about was some of the things we need to work on. We have seen some externalities. Each year we have an externality that we've seen where the market doesn't quite have confidence that that price is real, and it's not just an administrative oversight.

But we're very close, in my opinion. I think there are some areas of the market where there aren't those issues, and you aren't seeing a lot of complaints in those areas. But I think the western side has some externalities remaining. I talked about the DR issue. We've got to make sure those obligations are in balance, and we can sustain it in the long term.

The same with imports. Imports are a great thing, but the point is they have to be reliable. They have to get there when you need them, and I'm not sure we have that balance struck quite yet. I think overall, you'll see it evolve with a few minor modifications.

COMMISSIONER LA FLEUR: Dr. Patton, we're here for our checkup.

MR. PATTON: I thought I demonstrated such self-control not to refer to any other markets.

(Laughter.)

MR. PATTON: But I think to your point, it's important to recognize that you can, in well-functioning markets you can forecast what prices are going to be as you approach criteria. It's not like you have to wait and see what prices are, especially in well-designed capacity markets. So I think it's incumbent on us, as market monitors, and on the ISOs and stakeholders in general, to go through that exercise and insure that the prices that you expect to prevail when we start getting tight are sufficient to cover the entry of a new unit.

The one place in New York where we've seen that is New York City. We've seen investment in transmission. We've seen investments in units as units retire. Some of those are supported publicly, and some are not. I think it's generally worked, although you know there's definitely more work to do.

MR. BOWRING: As Andy pointed out, we have seen exactly what you suggest occur in PJM markets, particularly in the eastern LDAs where the market's tight. Again, subject to my caveats about prices actually not being high enough given the suppressive effects of a couple of market design elements.

In terms of the single-year forward, three years forward, I do think it is adequate to incent investment. I think we've demonstrated, the market has demonstrated, that it is. But as both my colleagues here have said, it's critical that participants have some faith that the market is going to continue, that it's not going to radically change. I mean, it needs to change. And really, more importantly, that the market will reflect the fundamentals. If the market needs to change to reflect the fundamentals, I think that would be a good thing. Investors would think that was a good thing, and the reverse not.

As far as net CONE, one of the problems with net CONE, just as a construct, is that it's backwards-looking. So it uses an estimate of growth, but it looks three years back with the historical net revenues. One thing you can be sure about three years ahead with historical net revenues is, they are a very bad predictor about what's going to happen at the time you actually want to build the plant.

So, when people build new plants, and they come in under the new offer rules, they will not have used forward-looking net revenues. But if you get net CONE right, then I would also agree with what Andy said. Something like that is where you want the price to be. It might be low as a result of competition.

Thank you.

MR. MUKERJI: If you get the CONE right, long-term you'll get right-year requirements. If you are on the CONE, we said the demand curve might be higher. The symptom will not be you carry a little bit of excess capacity, because more units can live with that rate of return. If you set it too low, you will not get the investment and you get into reliability issues.

In some ways, the demand curve is self-correcting. It's not perfect. It's designed to have it at requirement, and the price to clear right around CONE. But the level of excess the market is carrying is a symptom of whether it's set right or not.

COMMISSIONER LA FLEUR: Thank you.

Just switching gears, with the caveat that I do understand the value of stability, I want to ask a little bit of a blue-sky question. When I used to run a distribution company, one of the questions I used to ask the engineers is, if you lost everything, and you were putting up new lines -- we could make up the voltages, you were putting up a new system -- what will you put up? Probably wouldn't look like exactly what you have.

You've all been at this for more than a decade, and you've been through a lot of stakeholder processes with compromises, maybe even Commission decisions you didn't like.

(Laughter.)

COMMISSIONER LA FLEUR: But if you were starting, and now you're building a capacity market now, are there things you might do differently?

MR. ETHIER: Since I'm on the end, I guess I'll go first.

I think if there were one thing I could change -- and I don't have a good way to go about doing this -- it would be a more robust demand side of the market. What I see, a lot of the problems that arise with capacity markets, and the reason they're so controversial, is because the ISO is taking the role of the demand side, what ought to be the demand side of the market.

A world with more robust bilateral engagement, with more robust load-serving entities, with long-term sort of obligations, frankly, to serve load, or at least long-term market interest in serving load, I think would facilitate this discussion a lot. Right now, what we have in New England is, we have the load-serving entities for a range of reasons, some of them regulatory, some of them market-driven, presumably, have a relatively short-term focus, and so that tends to prevent them from entering into long-term agreements with the supply side of the house.

That makes these discussions much harder when you have one side and you have another side. I think these discussions, and the market, would be much more successful if you had that long-term counter-party to go with the resource side, which tends to be long-term in nature because these are long-lived investments.

COMMISSIONER LA FLEUR: What would they do differently? They'd make more long-term contracts?

MR. ETHIER: Yes. I think there are a lot of models out there. It could be long-term models. I think one model we're seeing evolving somewhat in New England is more of, you serve load and you also own generation, so that makes you have a more balanced perspective on the market, and also just sort of facilitates the market transactions. You're in the capacity market more for the spot, you know, sort of incremental long-short adjustments than you are for the entirety of your load.

COMMISSIONER LA FLEUR: Thank you.

MR. MUKERJI: If we had perfect hindsight when we created the market in the early 2000s, we would have probably pre-defined the zones that David talks about. We did recognize the fact that New York City and Long Island should be their own zones. But it's easier to set market structure at the onset than change them.

So we would probably have done that. And the other thing would be, if we had collaborated, had the same design between New York, PJM and New England, it would have been nice.

(Laughter.)

MR. OTT: I think when we formed -- obviously, it was a very contentious first capacity auction -- there were compromises made along the way. I think the basic structure of the market seems like it is an approach that works. So I think in hindsight, some of the compromises that were made actually made the market vulnerable to these externalities that I mentioned. So if we'd have spent more effort to say, look, we can't make those compromises because it's going to make the market more susceptible --

COMMISSIONER LA FLEUR: You mean like buyer market power?

MR. OTT: Ignoring the buyer market power issue. The other was the actual slope of the demand curve was cut off, and again that creates some of the risk that we see. The performance of setting obligations for all resources, you know, consistently in operations, we made some compromises there early on that we're going to deal with operationally.

So some of those did actually contribute. Probably in hindsight, we'd have started earlier, meaning we'd have done it a couple years before, and probably have been more successful there. But all in all, I think the basic structure seemed to be right, but the compromises -- again, it was a very difficult situation, and I'm not sure you could have come through it without compromises.

MR. BOWRING: I think the basic elements of the design are fine. As I pointed out in my earlier comments, I think the problems arise when we've strayed from them. If you stick to the essential elements of the design, what is demand and what is supply; what's the definition of capacity. And despite all the temptations to do one-offs and not do those, I think you have a pretty good design.

Actually, I would say a little bit different than

Rana on the LDAs. While predefining zone looks good if you don't have any zones, I would say the next step beyond that is actually letting them be more flexible, base it on the nodal, and have it reflect the underlying transmission system realities as they change. There's no magic to a transmission zone LDA.

One related matter on that, which is: I would have a tighter link between the reliability standards applied under the transmission system -- n-1-1 -- rather than just n-1 in the reliability market, so you don't get into RMR situations. You have the LDAs actually reflect the same reliability criteria that the RTO would apply when deciding whether to let some of them retire.

I would second what Bob said, and that's really more, in my view, about the interaction between wholesale and retail. But the evolving interaction between wholesale and retail is critical, I think, making both markets work better, both the retail side and the wholesale side.

COMMISSIONER LA FLEUR: Do you think the pressures to stray from the purity of the market design are accelerating, or has it been just constant all the time?

MR. BOWRING: I'm not sure. I'd say they've been constant, although I think they are abating. I think people realize that even though you have narrow interests and short-term interests, that everyone was better off if you stick to the fundamentals. That's my optimistic view. I think it's right.

MR. PATTON: A couple things. A private capacity market would have been really, I think, useful to focus on first, and then figure out what residual role a capacity market needs. And I think the first and most important is really, really good shortage pricing that prices locational shortages and prices shortages marketwide at a level that reflects what electricity is really worth, so that you get as much of the revenues to support long-term decisions into the energy market as you can.

That really does motivate people to be more flexible, to be more available. And then, getting to the capacity market, I think there I would agree with Joe that what we say in our state of the market report is, pre-defined zones or interfaces -- the interfaces are actually better. Essentially, it divides west and east New York, and it's the reason why you need capacity on the eastern side or the constraints coming into southeastern New York.

The reality is that some generators overload that interface, and some generators have a very beneficial effect on that interface, and there's no reason not to reflect that in the capacity market and have a capacity price that's higher for particularly beneficial resources. And then the sloped demand curve would definitely be something that I would have in there from Day One. It's been a long struggle to get that to work right.

COMMISSIONER LA FLEUR: Thank you very much.

MR. DENNIS: Thanks.

We're running a little over, but I want to make sure Commissioner Clark has some time for questions.

COMMISSIONER CLARK: Just so we can get back on schedule, I've got lots of questions, but I'm going to ask one just quick, discrete one. I think it's discrete.

In all the comments that we've heard this morning, and in a good deal of the submitted testimony, it doesn't seem like you hear a lot of people arguing that a strict vertical demand curve is a good thing. To draw on the physician analogy, it may be sort of the regulatory equivalent of high cholesterol.

(Laughter.)

COMMISSIONER CLARK: I know it's been a good deal of discussion in New England. I'll direct it at Bob. Could you just give a status report for what is the status of the stakeholder process, discussions in New England, and so on and so forth, with regard to the vertical demand curve and what may come next. Dr. Patton, if you have anything to add to that, please do.

MR. ETHIER: My arteries are hardening as we speak.

(Laughter.)

MR. ETHIER: Currently what we're discussing, as I mentioned, the performance incentives in our capacity market, and we expect that to run through the end of this year. We expect to have a vote in December and file with you all by the end of the year.

Our expectation is that in the first quarter of next year, we would start discussions with stakeholders about a sloped demand curve. I'm unwilling to put a timeline on that, because almost certainly it would be too short. I expect it's going to be extended conversation. The performance, the extent of discussions has been a bit over a year already. By the time it's done it will be a year and a third, a year and a quarter. I would expect the sloped demand curve to be similar in time frame, just because there's a lot of interest in the region and there will be a lot of concerns and a lot of folks weighing in on it.

So our goal would, of course, be to get you something by next year. I'm not sure when next year.

MR. PATTON: Just to sort of step back: remember when I said it's as simple as beef up shortage pricing and try to get the missing money, default energy revenues above maybe the value of offload or capacity revenue? We participate in New England as well and have been talking to them.

The performance incentive you can think of as turbocharged energy prices, shortage prices that may be, you know, five to ten times higher than any shortage prices you've seen. So I think there's a question of whether there's any revenue left to generate via a sloped demand curve in New England, you know, if that gets approved.

That would be my comment on New England. I think, obviously, demand curves exist in the other two areas. Thank you.

MR. DENNIS: Thanks very much.

We're going to do a quick switchout here and keep moving, rather than taking a break. Our RTO and ISO representatives, as well as the market monitors, will be over there and available throughout the day.

So if we can do a very quick switch and get moving, that would be great.

(Pause.)

MR. DENNIS: Let's go ahead and get started. If folks could head back to their seats, I'd appreciate it.

We are almost a full panel. I'm going to go ahead and introduce this panel and then turn it over to the Commissioners. Thank you.

This panel is titled -- and I lost my title -- mechanics of current centralized capacity markets. And I'll introduce the panelists, and then turn it over to Commissioner Norris for the first round of questions.

On this panel, we hope to have Dan Curran from EnerNOC; Lee Davis from NRG Energy; Julien Dumoulin-Smith, from UBS Investment Research; James Jablonski, from the Public Power Association of New Jersey; Richard Miller, from ConEd; Roy Shanker, an independent consultant; and Todd Snitchler, chairman of the Public Utilities Commission of Ohio.

While we're waiting for Mr. Curran, perhaps we'll start with you, Mr. Davis. I'm sorry; we're not doing -- I'm violating my own rule. We're not doing statements. We're going straight to questions.

Commissioner Norris?

COMMISSIONER NORRIS: Got you all excited there for a second, didn't you?

(Laughter.)

COMMISSIONER NORRIS: Mine's a bit of a follow-up question that Commissioner LaFleur asked. But let me set the table here.

You just heard the three RTO panelists before you, and while I think they characterized some issues they have to address, a general belief that their capacity markets are fairly well-functioning -- some even indicated better than their neighbors's. So let me give you an opening opportunity here. I'll just say that everyone has a chance to respond -- the first panel doesn't get a chance to respond -- to today's comments in writing on the record from the Commission. So everyone's got a chance to give a response.

But I'll give this panel a chance to respond. I'll characterize it this way. They all said they think their capacity markets are working fairly well, with addressing a few minor adjustments. If you had to name one or two design elements with regard to the mechanics of their centralized capacity markets that are currently, in your mind -- and some of you addressed these in your comments -- very problematic or troublesome, or are very likely to be in the future that need to be addressed, what one or two design elements of any or all of those RTOs would you point out? Whoever wants to go first.

MR. SHANKER: I'll speak up, sure.

If we're looking in hindsight, and I think that was the way the question came out before, what would you change? I think the point I tried to make in the statement was, you collectively, the Commission, over time had almost all the pieces correct. Lots of the pieces got swept away, compromised away, settled away and eroded. The best general instruction I would give is, go back and look what you approved.

If you looked at the best of it, you would have everything you need. But the kinds of exceptions that weren't there but are creating problems, I think the 2 1/2 percent is a great issue in PJM -- that holdout is blatant price discrimination. It should never have been there. It was one of those argued things that, you know, we can't go into settlements, but it popped out, and it probably was a mistake.

I think the comparability of product definition may have been overlooked. I don't think it was well-enough understood, and I think it raises the issues that Andy talked about. You have products that are callable 60 hours a year, fundamentally getting close to the same compensation as operating facilities that can be running 8760. Noticeability -- this is mostly in the DR areas.

You need to make comparable products. The predicate of all this is comparability is one price -- we do distinguish slightly in price -- but having one price, having comparable goods, having clearing markets, fundamental issues, and we keep creeping away from them.

Another example is, I think we had the demand curve right. I think New England did, I think PJM did, on their initial cuts. And Andy mentioned they got truncated. Actually, the slopes were changed to do exactly the wrong thing. You know, theory tells you some instruction about which way they should have been shaped. Settlement actually inverted them.

The things to fix are things actually you really fixed to begin with. If you read the Commission's initial order in PJM and the ALJ's order in Devin New England, most of the stuff that's in there, we'd be a little bit better off than we are today.

MR. SNITCHLER: Thanks.

Generally speaking, I would echo some of the comments that were first made, but I think the one that we noted in my comments really dealt with how we're addressing the compensation of capacity. And we're treating all capacity products equal, whether it's iron in the ground versus the willingness to terminate or suspend service, or even energy efficiency -- all of which are laudable goals. And energy efficiency, as I note in my comments, really is a cost savings, and that in and of itself ought to have some inherent value where it doesn't need to be compensated at the same level as an entity that may be willing to invest hundreds of millions or billions of dollars in a new generating facility that's in the ground.

I think that that's one of the issues as we look at how we're treating and defining products that would allow for greater reliability. Commissioner LaFleur mentioned that in some of her questions. Really, as the state regulator, those are the issues where the rubber meets the road for us, because we're the ones who get the phone calls when the lights go out, and we need to make sure that we're meeting our obligations to make sure the system is operating reliably.

Transmission solutions will solve some of that, but so will new generation solutions. And in a state like Ohio, and some of my midwestern colleagues that have substantial coal assets that are now either already retiring or scheduled to retire over the next two years, the issue of reliability and sufficient capacity to be able to meet those needs is one of the things that's very top-of-mind for us.

So making sure that we're getting the right signals to get the right kind of outcomes to insure that the lights stay on, and that the system can operate effectively and efficiently, is one of the areas that we think that some improvement with regard to the compensation piece for these other services would be helpful in making sure we get the best balance of all fuel sources, whether it's megawatts in an efficiency perspective or it's new generation to replace some of the coal that's going off-line.

MR. DUMOULIN-SMITH: So, perhaps following up on some of this last discussion, I broadly agree with it. I perhaps want to start off by offering something perhaps just a little less conventional in addressing sort of the bidding element of this all.

To a certain extent, we've been talking about net CONE and entry of new generators broadly speaking. But I think the evidence would suggest, largely speaking of late, it's been dealing with retirements, and what existing generators can bid into these markets. And ultimately, those who opt to retire would lack the missing money, if you will.

So perhaps the first concept that I'd proffer would be, just improving the bidding design to which generators can offer into these markets, rather than necessarily addressing the demand curve per se. Specifically, the return on and of capital is something that, I would particularly stress, has been lacking in the conversation.

Specifically, going-forward costs has been sort of a go-to in a lot of the constructs that FERC has been contemplating. I would proffer, specifically return of capital. Perhaps return on capital is a bit arbitrary ultimately. But return of capital -- I would argue that there are sufficient constructs out there that you can say, there's a 30- or 40-year life on a given asset, and perhaps you can bid that in as part of your revenue requirement.

So I go back to it. Ultimately prices have been trending down in a lot of capacity markets, given demand trends, given the oversupply in a lot of the markets. I would really urge to focus on this element of the capacity market construct overall.

That's the first point. The second point, further points that I would go back to here, kind of the prior discussion -- a multiyear construct, I think there was some discussion. Is three years sufficient? Right, we're pushing the spot market three years forward. Ultimately, I go back to it. A restructured market ultimately, in some senses, has a little bit of a duration mismatch in the life of these underlying assets, right. I understand it's difficult and challenging to work past some of the issues. But ideally, you would look past and have a longer-term, at least new-entrant option, and perhaps offer that ability for incumbents to maintain sort of a comparability in bidding models, but ultimately allowing for that option I think is key in reducing the cost of capital.

Let me make this point very clear. The cost of capital is inversely related with the duration of the contract allowed for. In this case, this is a three-year contract, typically speaking, and it is not necessarily a linear one, either. I would proffer that that's well worth paying attention to. And again, going back to the underlying framework, the cost of capital embedded in a lot of these products is frequently overlooked in view of going forward costs, et cetera.

Beyond this, there was talk about energy offset, if you will. I want to go back to this point again, with the view that a lot of the discussions of late are, can we keep existing assets connected. Do we disconnect? Is the missing money problem structural? Is it specific to me, and should I retire?

I think going back to this, we should be cognizant to recognize that a lot of the units that we are talking about are coal and nuclear units, to be specific. And in some sense, to think about it from that perspective, we're talking about to what extent are the energy revenues and the offsets in net CONE complimentary to the energy market cycle, right; explicitly, natural gas prices are low, so therefore the competitiveness of competing fuel sources needs -- or in theory should -- be addressed via the net CONE mechanism.

Again, to that end, one should strive to improve the coherence of the energy offset. Again, perhaps going back to some of the comments, it should be forward-looking such that the forward-looking outlook is explicitly complimentary and represented through the capacity revenues.

I suppose lastly, in terms of proxy units, just to tackle that briefly, peaker versus combined cycle versus perhaps some other technology -- I would just encourage you all to take note: the other technologies are coming in, right. A combined cycle is going to get constructed in a world in which a peaker is still a proxy unit. I would encourage you to reflect and derive net CONE rather off of what is a reliability unit rather than what is the cheapest technology du jour.

Again, in some senses, if I were to switch to a combined cycle, that would exacerbate the energy market cycle, because energy prices and explicitly natural gas prices would prefer a combined cycle in this case. So again, if you talk about viability and continuity in the construct, I would suggest -- focus on the technology and the reliability characteristics, rather than the technology du jour.

Taken to its logical conclusion, one would say demand response would be the cheapest incremental source. But I'm not sure that would be the best outcome for a net CONE construct. So I'll leave it there.

MR. DAVIS: Hi, good morning.

I'm in general in raging agreement with what's been said so far, but there are three things I'd like to point out in relation to how we make decisions to either enter the market or exit the market as a generator.

The first one is, you know, the advancement of locational pricing is extremely important to us. If you look at the markets which we operate in New England, New York and PJM, we've been able to make decisions in PJM based on the locational price separation in an ANSI zone, where we were able to bring back capacity at a very, very cheap price to the system and enable reliability to continue in Ohio and Pennsylvania.

As you look across New England, for example, the gentleman talked about forward capacity zones, pricing zones. We'd like to see that expanded into additional pricing zones where we can get better transparency on where the need is on the capacity side, as well.

Further on the demand slope, we're in agreement that there should be a demand slope in New England, and it seems to me that that should be something that should be a priority today, rather than waiting until the subsequent years to address that.

The third piece is regarding western PJM, which we have a reasonably large footprint in western PJM. If you look at the amount of imports that are coming into western PJM, there needs to be a mechanism -- I agree with what Andy had to say earlier today about addressing that sooner rather than later, because of the long-term reliability impacts of having that displace generation that exists today in western PJM.

MR. MILLER: Thank you.

ConEdison thinks that the NYISO markets are good. I just wanted to make that clear. But we think they can be better. The first area that we would like to see is a more forward market. And if I contract what was said in the prior panel, I think Dr. Patton took the position that a forward market is not necessarily necessary to encourage new entry. But what Mr. Ott talked about is how where a forward market can aid in managing retirements, and that's where we have a particular concern, where we recently had to manage a retirement in New York City based upon very short-term notice, and we think that a three-year forward signal would greatly help with something like that. So that's why we still favor a forward market, not just for the issue of facilitating new entry, but for managing retirements.

With respect to just Dr. Patton's claim that maybe this could be solved by managing, by creating zones based upon transmission security concerns, I would just point out that that raises a lot of concern on our part in ConEdison. A transmission security zone for us could be one neighborhood in Queens. We just wonder about dealing with the market power issues with something like that.

Secondly, we would like to see the categorical exemptions on buyer-side mitigation adopted. We think in particular the competitive entry exemption is very important, again in terms of managing retirements. Here, we completely agree with Dr. Patton. He recently made an excellent point, we think, at the NYISO that if a developer has a disagreement with the NYISO as to its assumptions as to what generation may retire, it should be allowed to go forward with that unit.

Right now, the NYISO very understandably is conservative as to what it may estimate for generator retirements. But that means that maybe somebody won't come in who should be coming in because of the conservative assumptions of the NYISO, and they won't be able to do that because of the lack of a competitive entry exemption. So we think also this is a critically-important change that would be essential for the NYISO markets.

Finally, just with respect to what Julien said on the proxy units of the demand curve, I agree with him that this is a difficult, complicated question, and that moving away from the CT is not something that should be taken lightly. I will just say that our position has been that there should be no legal or tariff bar towards using something other than a CT as the proxy unit in the demand curve, and that that would be a very important change to make.

We're certainly willing to rely on whatever the determination is of an independent consultant as to what's the best proxy unit for the demand curve, subject to the

Commission's review. But there should not be any restriction in any tariff as to what the independent consultant would choose as appropriate for the proxy unit and for the demand curve as exists in the NYISO tariff right now. As Mr. Mukerji pointed out, that change unfortunately failed in the NYISO stakeholder process.

MR. SHANKER: Two out of three isn't bad, Rich, but I'll agree with you. There's a history there.

The forward market, I think, is important, and I disagree with David on that. Retirement is important. Transmission planning and comparability of transmission opportunity is equally important. We have huge biases in favor of transmission solutions that are structural because of the temporal issue. You can't come up with the solution and slink to retirement. You can't come up with it overnight. You create all these incentives for RMR issues that you can work your way out of if there is a sufficient lead time.

You have the general solution that you're giving supply elasticity an opportunity. But you're also allowing -- the PJM auction allows, I think it could be better if it was even a longer lead time -- allows transmission to compete directly. But the transmission planning cycle preempts the capacity procurement by a minimum of two years.

Those things need to be evened up. But even to talk about evening them up, you've got to have a forward market. It makes it easy to plan for retirement. It makes it easy to retain people, give them the price signal to retain, have orderly exit from the market -- very important elements. And then the flippant one is, oh yes, it allows for price elasticity. But it does. You know, it sends a signal and it does facilitate physical new entry.

The competitive entry exemption I agree with completely. I sponsored testimony on that about five or six years ago that was rejected by the Commission for New England. But it makes perfect sense. I referred to it as the stupid money problem. It's not our concern if somebody out of market support chooses to make a judgment different from the rest of the market. It happens every day. If they want to put their funds at risk, there's no non-bypassable surcharge. There's no subsidy. There's no third-party distortion, you know, buyer-side market power issues. They should be able to do whatever they want. It's their money.

COMMISSIONER NORRIS: Let me move to the rest of the panel, sir, so we can get through this question.

MR. SHANKER: Sure, okay. Just one quick thing, is I strongly disagree about the proxy. There is a technical reason why the peaker is correct. If you think about it as you go through the load cycle, the shape of the load duration curve changes. The relative economics of peakers and combined cycles change because of the utilization.

So, as the shape of the load duration curve changes, you'll see times when a combined cycle is cheaper. And what happens is, you convert your way into more people supplying combined cycle plants, and you still wind up with peaker at the margin. So over time, what you wind up doing as you do this, you pay average based on a peaker as a target some of the time, and less than average the rest of the time. It's just fundamentally wrong to be swapping that out.

COMMISSIONER NORRIS: Jim?

MR. JABLONSKI: Yes, thank you, Commissioner. Thanks for the opportunity to be here.

I'll give three quick points. One is, and it was talked about earlier, is really a by-product of the markets, the volatility in price is a great concern that we have. Originally, as we understood and now understand what would happen with the centralized capacity market of RPM and PJM is, we'd have some pain for a period of time and that prices would go up from what were about $10 to $20 a megawatt day to whatever point they would go up, see perhaps a leveling off, and then come down because the capacity would be constructed where it needs to be, and/or transmission, and we'd go back to having the capacity that we need and therefore see an easing in prices. It's kind of like those road signs that say, you know, when there's construction: temporary inconvenience for a permanent improvement.

Understanding it wouldn't be permanent -- there would be some ups and down -- but the volatility needs to be addressed. Since we talk so much about the administrative aspects to the centralized markets, perhaps there could just be some sort of administrative limit considered from year to year, both up and down, so that there is some stability.

The second item is LDA prices versus the reality of the LDA, to sum it up, particularly in the state of New Jersey, but across 13 states and the District of Columbia for PJM and the other RTOs/ISOs represented here. There has to be pockets of dense population, such as New Jersey, the most densely populated state in the country. But also in New Jersey, and a lot of people don't realize this, a lot of the land is protected by one level of government or another as a park or refuge or what have you. So there's very little place to build anything in New Jersey, except for perhaps the properties that have had or have capacity now.

When you have an LDA generate a price of $245 a megawatt day, but that LDA, there's almost no place to build anything that would solve that problem, the price is really not going to provide an incentive, because there are other barriers such as the availability of land, and likely others. So it just occurs to us that perhaps there should be some consideration given to the reality on the ground, and not just standing up and saying, well, the market says something has to be built there, so build it. Sometimes that can't be done, and I think that should be recognized.

The last thing is, just quickly, you know, there was a lot of talk on the first panel about the minimum offer price rule and exceptions, exemptions, whatever you want to call them. Speaking on behalf of our folks in New Jersey, and I've relayed the experience that covers most of the content of my comments, of the city of Vineland in the state of New Jersey -- and I won't regurgitate that now. But I believe I speak for mumicipals and rural electric coops: we don't want an exception or an exemption. We just want you to put back the way it was the 2006 provision under the settlement. We don't bother you, you don't bother us -- however you want to put it. But that gives us the opportunity to fulfill our mission.

We don't necessarily enjoy having to go through all these processes and spend all the money that needs to be spent. But with that provision, we're here -- the 2006 provisions. We're here. We're the same as we were then when that settlement was reached. We haven't changed. We don't intend to impact the outcome of any markets. We just wish and believe the Commission could just go back and say, look, we're going to put this back the way it was. Figure out the other ones, unit-specific, whatever else you need, but that would be appreciated.

Thank you.

COMMISSIONER NORRIS: Dan, I think you had not commented yet.

MR. CURRAN: Thank you.

I wanted to start by thanking the Commissioners for giving us a chance to speak today. To start off, we certainly agree with what I think is the consensus here that centralized capacity markets have been effective, both in terms of insuring reliability and in doing that in a way that we think produces just and reasonable rates.

On top of that, we would like to state, which you're probably not surprised to hear, that we believe that demand response has been very beneficial to these markets in terms of providing a diversity of fuel, and in terms of providing fast and reliable rates of response, and in terms of adding I think a needed measure of price elasticity on the supply side.

In terms of thinking about how we might, you know, suggest changes going forward, and maybe in addition how we might have operated differently in the past, I think one guiding principle that we'd like to reiterate is the importance of being clear on the definition of capacity.

There was a matter in PJM which I know we're all aware of a year or two ago in which the definition of capacity for demand response fundamentally changed. And I think it's critical to understand what kind of challenges that poses to a firm that's trying to make a long-term investment in a market.

It really ties back to the broader point of the importance of having stable markets, where there's certainty around any future changes. That's, you know, balanced with the need to have these markets certainly respond to the dynamic needs of the system.

Second, in terms of the rules for all participants, but certainly for demand response, we think there's a need to appropriately balance the complexity and the clarity of the rules. When we look across these three markets in terms of things like technology, measurement and verification, and qualification, there is a huge gulf between these markets in terms of the complexity of the rules, and it's not clear that where the rules have been most complex that it serves a benefit to the system. In fact, we think that overly complex rules that really obscure the clarity of how a market operates, certainly for demand response customers, can be counterproductive and can serve as a barrier to entry to the markets.

I think last, there's been a lot of discussion around the flexibility of demand response in a capacity construct, and whether or not the levels of demand response, certainly in a region like PJM, are starting to impose constraints around PJM's ability to appropriately use that from a reliability standpoint. We believe there is much to be gained in terms of additional flexibility from demand response.

In terms of what we're seeing right now in terms of proposed rule changes going forward, we think there is a big divide between what's been proposed right now, which is basically a full integration of the energy market, and a lot of stuff that we think could be achieved to produce the same result, but frankly would be much more effective.

MR. DENNIS: Thanks.

I just wanted to ask folks, just to make sure we have plenty of time for all the Commissioners that have questions, to the extent things are in your testimony, if you'd refer to those, that would help. It's an unfair request, but to keep responses as tight as possible, we'd appreciate it. Thanks.

COMMISSIONER NORRIS: I think that took more time than I thought, so I'll save my next question and pass it on. Cheryl?

COMMISSIONER LA FLEUR: Thank you.

I would like to talk to you as investors, starting with Julien, but all of you, many of you invest in the markets in different ways or advise boards or other people. We've talked about a lot of this. I know the devil is in the details. We've gone into a lot of details.

What are the most important aspects of the capacity market as you look and you decide, I'm going to put money in or I'm going to take money out? Do you think we're ever guilty of, like, overvaluing this bit -- it's more than a bit -- this 15 percent of the money or whatever it is that a generator gets paid, versus the energy and the ancillary services markets? Why are they so much -- I'm interested in how you assess that when you make a decision to go in, the different streams of revenue coming to the plants.

MR. DUMOULIN-SMITH: Thank you, Commissioner.

Let me just make a first observation, and that is the value proposition of capacity being visible for at least a three-year period is, in theory, conceptually, a superior value proposition to sort of a fickle or volatile energy market signal. That should be apparent.

However, in the markets today, there is a discount to energy revenues placed on capacity requirements, given the volatility in prices and given the uncertainty in rules that results in this outcome. And you can look at a number of historical transactions. I'll save the list here. But rest assured that that is the case, at least empirically speaking.

Perhaps speaking more theoretically here, as you look at prices historically -- and again I go back to my construct; it's about saving assets on the margin, it's about investing in incumbent assets, in existing assets rather than necessarily new ones today. And from that perspective, to what extent I suppose have prices been sustainable and viable, and is there a viable construct to see prices recover?

Again, I go back to some of the comments that were made in the last panel. Is there an inadequate construct in the neighboring region, et cetera, that impedes or for some reason undermines the viability of the construct? Because what's been impressive, at least from my perspective, has been the ability for markets to recover subsequent to minimum offer price rules being implemented, right.

So I think from that perspective, the credibility of the markets is indeed intact. And fundamentally, there is ample capital to be invested in the power sector, should it be attractive. I do not doubt that for a second. Rather, it is all about price signal, and again that relationship between the visibility of the revenue provided and the cost of the appropriate capital.

COMMISSIONER LA FLEUR: In answering Commissioner

Norris' question, I think you talked about a new entrant option. Did you mean freezing the prices for a certain number of years?

MR. DUMOULIN-SMITH: Explicitly I was referring to providing a longer-than-three-year option for new entrants. Five or seven -- I know it can be challenging, particularly to provide a non-discriminatory construct. But ultimately, that seems like an exceptional way to encourage new entrants. Look at, I suppose -- not to mention too many other markets, but California is now trending towards a ten-year market. That is notable.

MR. DAVIS: The company I represent invests in new and existing generation across PJM, New York, New England and California and Texas as well. And one of my responsibilities is to look at how we invest into PJM, New York and New England. I must say, there are several gating items that we think about internally when we attempt to make the decision to invest, and the first one is stability of market rules. You know, that's the easiest answer ever, right, in an environment like this.

You know, to compare two markets versus each other, the PJM market and the New England market, where we hold substantial amounts of capacity in both -- the last PJM base residual auction, we actually re-entered about 1500 megawatts of capacity into western PJM, based off of our view of what market signals would be in that auction. And the market signals supported our decision to move forward, and we cleared, and we're investing hundreds of millions of dollars now in restoring facilities that otherwise would have been retired by the company we merged with previously.

That's important to us, because as we look at making investment decisions, not only on environmental controls, restoration of units, or adding different fuel types to units, we look to the stability of how those rules are formed in those markets to make that decision. In New England, on the other hand, we made the decision to retire early one of our generation units that has had exceptional performance in the markets over the past ten years. The primary reason for that decision to retire that unit was, A, we're making a marginal amount of money on that that does not reflect the risk of where we believe market rules are forming in New England.

So we decided to go ahead and take that asset out, even before the summer runs commence, and that's the first time that our company has made that decision for an asset such as that. But we look at risk just as highly as we look at revenues when we make those decisions.

The other things are, obviously, the ability to predict energy and capacity revenues, and we holistically look at our decisions around both of those. Obviously, with capacity revenues being something that is viewed more stable for us, we're much more willing to invest now, because of the low energy markets, in assets that have some type of ability to withstand the markets and participate in the capacity revenue stream.

Again, there must be a balance between capacity and energy. You know, the discussions around the ability to allow energy prices to free up during times of constraint, that's extremely important to us. In fact, the assets that we're pushing back into the market, and ANSI has received those types of payment this year, and it's very encouraging to our investors to see that balance between the capacity markets and the energy markets unfold.

COMMISSIONER LA FLEUR: Roy?

MR. SHANKER: I helped a small independent -- someone with no outside funds -- participate in the last PJM auction, newly-powered 800-, 900-megawatt unit. And so daily we had discussions of the question that you were asking. If I could put the priorities, one, it's the risk of change. What am I going to be seeing next year? Are the rules going to be the same? What can I do?

The second was a huge concern with the issue of out-of-market and related -- buyer market power as a form of out-of-market, or other out-of-market actions that would undercut the value of capacity for them, and energy.

Because those effectively become must-offers as price takers into the market. There was a significant concern about getting a handle on that in the face of -- well, there's going to be a lot of coal retirements. How likely is it that I'm going to have otherwise uneconomic units retained in the market, and I'll be competing against them when I'm basing my view of the world on, I've got a competitive advantage over them and they're going to be sustained by out-of-market payments?

Interestingly, the energy side was probably -- it certainly wasn't unimportant, but it was the most manageable. Certainly within the PJM footprint, particularly because of the Marcellus, there are very attractive hedgeable, let's say out to 10-year transactions that weren't there three or four years ago. And so it changes that risk profile of business decisionmaking and puts a much heavier weight now on capacity. And the biggest weight in capacity is, I need to know what it's going to look like. It doesn't have to be a long-term contract, but it's got to be a predictable paradigm.

COMMISSIONER LA FLEUR: Thank you. Todd?

MR. SNITCHLER: Thank you, Commissioner.

I'll come back to your question, which as I took it was, what are the most important aspects concerning investment in the market? And as one that doesn't invest, but hears frequently from those who do or are seeking to invest, particularly in the Ohio marketplace, the common denominator or the common points of interest really are two.

One is a longer period looking forward, and we had asked PJM to consider that, and they had considered it. And, I believe it was last August, the committee that was evaluating that had elected not to go forward with a five or a seven-year construct, particularly with regard to new generation.

And so the second, really, issue that comes up is, it becomes a question of, am I going to invest my cap X dollars in questionable generation that I'm not sure I'll recover? Or do I just simply invest in my transmission solutions, which are also viable, workable alternatives. But the fundamental question at the end of the day, there must be a generating station somewhere at the end of that wire, or you can have all the transmission solutions you'd like, but you don't have any power to deliver. And it's what is the appropriate balance, and how do we properly incent investment in both categories, not one over the other or merely one in preference to the other.

So we are seeing some response with regards to, as mentioned, some of the shale gas issues, where costs may be lower, generation may be more attractive. But it remains a consistent message that we hear that a longer period of time, five to seven years, is what the investment community has told us through the entities that come to the Ohio Power Siting Board, would make it much more economically feasible for them to make the investments to build those gas units.

And I feel compelled to come back to the prior question that Commissioner Norris asked, and very briefly say: even as an economic regulator, I think we have some obligation to make sure we're monitoring and being aware of over-reliance on any one fuel source. Because at the end of the day, we need fuel diversity, and states like ours have some fuel diversity. It's growing, whether it's renewables, nuclear, coal or natural gas.

To simply solely focus on the absolute bottom dollar at the expense of system reliability and price stability over a long term is one of the things that I think we need to keep in mind as we make some of these economic decisions. There are broader policy forces that are also on the table that need to be considered by regulators.

COMMISSIONER LA FLEUR: Do you think those other considerations are -- obviously valid, about diversity, environment -- should somehow be cooked into the capacity markets, or taken into account otherwise?

MR. SNITCHLER: That's a great question for which I do not have a succinct answer.

COMMISSIONER LA FLEUR: Me neither. That's why I asked it.

MR. SNITCHLER: I think I would defer to the economists that would have maybe the better model on how to contemplate some of those things. As you establish whether it's your differentiation between classes of existing gen versus new generation resources, or the type of resource that's bidding in -- there are probably a number of ways to approach that. But I am certainly not qualified to opine on all of those.

COMMISSIONER LA FLEUR: I think the third panel is also more explicitly on that topic.

Mr. Miller?

MR. MILLER: Yes. Just a quick comment on our perspective as an investor. We're a fully divested utility that supports competitive markets, doesn't build generation, and our only concern is that nobody's going to ask us to finance a long-term contract or enter into reliability must-run agreements.

So it's actually an investment we would like to avoid, and make sure that the capacity markets work to avoid that investment.

COMMISSIONER LA FLEUR: Thank you.

Mr. Curran, from your perspective, you also make investments of where to put in the infrastructure to build DR. I just want to give you a chance, if there is -- as you look at these markets, especially the capacity markets, what you're looking for.

MR. CURRAN: Sure.

I think one thing to probably understand, and I think it's probably not a surprise, is that we're working on much shorter time frames in terms of both how quickly we can build, and also how quickly we can recoup the investments. So that's I think probably the biggest decision, or you know the biggest difference between demand response and generation. And I think that was evident in terms of what we saw for the clearing results in the PJM '16-'17 auctions, where demand response actually pulled out of the market in not a dramatic but a meaningful amount due to the low prices.

I think that highlights that supply elasticity, in that demand response doesn't have to act as a price taker. If prices start to drop, it can pull out of the market, and those resources will still be there. They'll still be there for the future, and if the need arises for them to reenter the market, you know, they'll be able to do so.

In terms of what we think about when we're investing, the potential pool of demand response resources is a really fluid concept. It has a lot, obviously, to do with the price that we expect. It also has to do with the available technology we have and that we invest in and that we build. That allows us access to certain customers that might otherwise not be able to participate today.

So we take both the price and the technology into account when we're dealing with capacity.

COMMISSIONER LA FLEUR: Thank you. I guess I'll give Commissioner Clark a turn.

COMMISSIONER CLARK: Thank you.

This issue of price volatility has taken up a lot of the discussion this morning, as well as a lot of the pre-filings that we receive. So I want to focus in on it a little bit more, but maybe ask the question a little bit differently. Because it seems like there is this tension between two concepts. One is, we have a pretty good laundry list of recommended changes that many of the commenters have brought forward that could help deal with the problem of price volatility, probably the potential for a four-year procurement or multiyear commitment being one of them; a downward-sloping demand curve appropriately set being another, and there's a whole laundry list of others.

But at the same time, there is this tension of the stability of rules is another sort of core concept that we've heard about. By its very nature, if we change the rules, then we're sort of violating that.

I'm wondering if -- just leave this open to the panel -- could you maybe not strictly rank, but give us an idea of those things that you've heard today where there's less bang for the buck, there seems to be less value? And there's that sort of tipping point where, yeah, the Commission could do this, and maybe in theory this is a good idea, but the instability that it brings to the rules and to the marketplace actually probably outweighs the value in seeing that particular change through.

And then, if there's one or two that just really jump out -- it's like, this is a slam dunk, no problem, it's worth the instability to the rules to make the change -- let me know that.

Mr. Davis?

MR. DAVIS: There's been a lot of discussion about competitive entry exemptions so you get the minimum offer price rules, and particularly in New York. There's been a lot of stakeholder conversation around that one issue for the past, mainly the biggest part of this year.

And I would just have to say, one observation of the minimum offer price rule and buyer-side mitigation in New York, we actually had substantial investment take place while that rule was in place, both state-sponsored and actual competitive entry that was able to clear that minimum offer price rule. My observation is: if we're able to have competitive entry under that minimum offer price rule, why does there need to be an exemption?

So that's the first piece. The second piece is, we're a large owner of generation in that state, but we're also a large developer as well. So we really like the idea of being able to enter the market. But we don't want to destabilize the prices in that market to where you're forcing RMRs and other things like that.

You know, as it relates to the competitive entry exemption, I would much rather focus on other things in the markets that aren't necessarily working right at all rather than trying to tweak that rule to where, you know, my investors that guide my decisions for my company see yet another change in the New York market that causes us to stop and think about it for another two or three years.

COMMISSIONER CLARK: Thanks. Julien?

MR. DUMOULIN-SMITH: Thank you, Commissioner.

Perhaps let me start this sort of constructively, if you will, in terms of what's the best bang for the buck, if I could delineate it. I think first, going back to the sort of notion of a black-and-white market. There's a restructured market and the regulated markets. It's a bit akin to the MOPR idea, but ultimately the notion of an FRR mechanism, the notion of having adequate MOPR rules across the board and allowing those to work across markets, a la transmission -- as long as that's very much intact, I think that will reduce the volatility. It will reduce the concerns about price suppression on a go-forward basis. Again, I use the analogy of black and white, because I think that should be the guiding principle.

Second, the notion of the best bang for the buck, a vertical demand curve, leads to price instability, period. You can walk around it by changing the bidding rules for generators to recover their investment both of and on and the going-forward costs, all three components in my mind, separate and distinct, and I frankly think those are the two best bangs for the buck.

As far as MOPR rules and the nuance within them, frankly, that might be at the lower end of the list, at least for PJM, if you will.

COMMISSIONER CLARK: Thank you.

Mr. Miller?

MR. MILLER: Just quickly to respond to Mr. Davis on the buyer-side mitigation, like I said, I think the NYISO markets are good. I think they could be much better. We think we have seen much more substantial merchant investment in new generation in PJM on a percentage of peak load basis than we have seen in New York, and we think that does have the possibility of real bang for the buck, notwithstanding the fact that there has been some merchant investment in New York.

On the concerns side, I just will go back one more time to what I alluded to earlier, that we're very concerned about price volatility from very small zones based upon transmission security in New York. We just don't see that much bang for the buck there.

COMMISSIONER CLARK: Thank you.

Dr. Shanker?

MR. SHANKER: Yes, Commissioner. I think maybe four items.

If there's things that you would do as a Commission that would impact the markets, the first would be to sort of sweep for price discrimination, and it shows up in lots of different ways. Dr. Bowring mentioned the 2 1/2 percent offset, you know, having a must-offer for 100 percent of supply, but only a 97 1/2 percent demand. It sort of implicitly builds an excess into the market. It implicitly denies transparency to new entry if load growth is ever less than 2 1/2 percent. It's certainly been the history for the last period of years.

He mentioned it's billions of dollars. It's an obvious fix. We aren't going to go through it here in time, but you can find lots of little mini-attempts at discrimination in price formation throughout a lot of each of the RTO rules.

The demand curve, I think -- the New York process

I would like to see it forward, but I think the New York process has been stable, and I think it's unbelievably argued, but it gets well-argued. And it's more of an adversarial than stakeholder process, but it works, so that's pretty good.

I have to say that process has become regimented. You know who's going to say what, but there's facts that go behind those statements and those positions, and it's been an interesting process the last now, I think, three years, three cycles at least.

The next bang for the buck, I guess I would say, is locational information -- making sure that we have, ideally it would be dynamic. I actually wrote something that looked like RPM in 2000, and it was an attempt at locational at a nodal basis. I don't know that that's really feasible. It was a nice idea in the abstract as a place to start. But all constraints should be in.

One of the things -- I differ with Rich on this -- is that the volatility that you may get by a constraint binding every now and then but not binding other times is very, very important price information. It's telling you, not so much about new entry, because we have a bias for building transmission to lead. It's really much more the locational signals, at least in the PJM market, are much more oriented towards retention. And that's because we have mandatory transmission fixes when there's variance between zones. It's an explicit violation that has to be addressed, and it's identified forward.

So if it's identified forward, and I know I'm going to fix it, and I'm going to converge the zones on a reliability basis, in the interim, I need to make sure the generation stays there.

And so, those locational signals, particularly that kind of volatility, is very, very important as a proxy or substitute for RMR. And it's a market-mechanism-based signal for retention.

Then I think the last thing -- it's a long list -- would be comparability of products. We have just too many things that don't look alike that are getting close to the same compensation, and it creates a lot of problems in the modeling. I mentioned in my paper, I won't go into it here, that I think some of that product lack of comparability has been mismodeled. It did some significant harm, I think, in terms of conveying information about the demand curve, over 90 percent of the market in PJM for two or three years. PJM's creditors recognize that, and they're putting changes in to try and fix it.

But the underlying problem was the lack of comparability of price. And that needs to get fixed. Andy's comments, whether it's 80 or 90 percent of DR in PJM is emergency services. It's priced at $1800, and it's performance-limited. And that's constituting whatever -- is it 8 percent of the market, 10 percent of the total market -- Joe and Andy can give you the exact numbers, but it's 12,000 megawatts in the LAS, so I guess that's about 8 percent.

It's almost all emergency, and it's almost all coming in block-loaded at the GAC price. So there's a real problem when you don't have a diversity of products or a comparability of products, and they get concentrated like that with no price division or functional or operational division.

COMMISSIONER CLARK: Thank you. Mr. Jablonski?

MR. JABLONSKI: Thank you, Commissioner.

I just want to go back, circle back for just a few seconds to Commissioner LaFleur's question about business decisions. In our case, it's really very straightforward. We look at the RPM prices, the capacity clearing prices, that we've seen, and we see where they're heading. We know we can build for less than that, so it makes no sense for us to buy from the capacity markets. We do our self-supply, and try to move forward and take care of our own customers by the old, traditional vertically-integrated utility format.

But our business model allows us to build for less, so it's a really relatively simple decision, assuming land is available and all those other things. But again, it was brought out -- we keep, both panels now, circling back to this minimum offer price rule and buyer side mitigation, et cetera -- you know, a big bang for the buck, at least as far as we can see it, I don't know how big it is in the overall scheme of things. We've been told, you know, look: you guys in public power, municipals, cooperatives, you're not the problem. The settlement in 2006 and those provisions, that was part of the basis for that. The 2011 activities in a case before FERC, again we were involved and again we were told, don't worry, you guys aren't the problem.

In 2012, PJM came forward with a filing which created the new self-supply exception and the competitive market rules. Again, throughout that process, we were involved; you're not the problem.

We come forward now to the current FERC case challenging the self-supply exception and the PJM stakeholder process, which is wanting to change to the unit-specific exception to the only somewhat unit-specific exception. We're facing great risk and uncertainty about whether we can go forward and be involved in the capacity market in terms of construction. And the problem for the entire market with that is, I thought that's what we wanted.

And if you're prevented in some way, shape or form by these rules, by saying to us, well, yeah, we understand that you can legitimately build for -- just throw a number out, $100 a megawatt day, but we're going to mitigate that up to $175, just because of the market. Then we have to walk away.

So, you know, it just seems again the best solution is to go back to the 2006 provisions, notwithstanding what happens with the rest. Because we're in double jeopardy with the self-supply challenge and the somewhat unit-specific exception that's now evolving at PJM.

COMMISSIONER CLARK: Thanks. Mr. Curran?

MR. CURRAN: I won't offer a long list of items, but if I could give you, you know, kind of one overarching concept in terms of bang for your buck with volatility, I think what we've see is that, you know, it's important to focus upstream. And what I mean by that is, there's been a lot of discussion in the past year over, are these capacity markets meant to be a physical market? And I think the answer to that that has come back has been a resounding yes, which we certainly agree with.

But there have been questions as to whether those physical resources are coming to bear in the market. And a lot of the current focus has been on the downstream delivery of those resources, which I think frankly is treating the symptoms and not the cause. I think PJM got it right in the past year with respect to demand response by looking at the upstream qualifications and making sure that resources that we're providing did indeed have the capability to physically deliver.

We believe that that process, which is still ongoing, has already started to have a positive impact on the market. And we think there are certainly other supply sectors, you know, that could certainly use a second look in terms of how the qualification process on a go-forward basis in terms of actually clearing these megawatts in a three-year construct, how that qualification is being handled right now.

COMMISSIONER CLARK: Thanks.

Just one more question, and I'll turn it over to the Chairman. One of the top questions for this particular panel was how effective the mechanics of this current market is for assuring resource adequacy at just and reasonable rates. This question goes in a little bit different direction than we've explored here this morning, but as we know, one of the presuppositions of a forward capacity market is in helping to plan for retirements. And yet what is required of generators who may be retiring units doesn't always match up with the forward capacity construct itself in terms of timelines. They may be able to shut down at very short notice, but it may not give time for these forward capacity markets to incorporate that information.

Are there any tweaks that need to be made to the construct to counter that, either on the capacity market side or on obligations of retiring generators themselves in terms of the amount of transparency they have to provide to the market on a forward-looking basis?

MR. SHANKER: What's the status of the filing for the change in the dates? Is that in front of the Commission or not?

VOICE: It's pending.

MR. SHANKER: Pending?

PJM has a docket on that, so we shouldn't talk about it.

COMMISSIONER CLARK: Thanks.

MR. MILLER: I would just, Commissioner, mention clarity on one issue -- Mr. Mukerji alluded to this -- that's still being worked on through the NYISO stakeholder process, not yet before the Commission. But I think at least what we have seen in the NYISO to date is that most generators have opted to use the mothball notice as opposed to the retirement notice, and that the mothball notice, because it contemplates a potential return to the market, creates a lot of uncertainty and confusion for a local utility that may be called upon to solve the reliability issue for that generator.

I won't debate what's going on in the NYISO stakeholder process right now in front of you. But I do think that this is one tweak that we think is essential, given the issues that we have faced so far on reliability.

COMMISSIONER CLARK: Julien?

MR. DUMOULIN-SMITH: Perhaps a quick comment. Maybe overall again, going back to the concept of retirement, broadly speaking, I would articulate that at this point of the cycle, this is really where we are. A lot of balance sheets are really quite stressed.

I would argue again, this suggests volatility is problematic. If I'm going to make a retirement decision that is structural -- the large facility that employs a lot of people, et cetera -- I argue that this goes right back to, we need to have very clear visibility and reduced volatility. Because if you want me around the next year, again, I'm going to be biased to go back to that mothball status.

Again, if you want to talk about the symptoms and the cause, I'm going to be biased to go towards the mothball-type arrangement, in whatever RTO. The reality is, send me a price signal -- should I retire? Should I not? -- and send me a reliable one, at that. Do you want limited DR replacing of the resources? I mean, that just needs to be very clear.

COMMISSIONER CLARK: Thanks. Dr. Shanker?

MR. SHANKER: In thinking about that, I was trying to isolate what could be said and what couldn't be said. There's a balance that you should all be aware of. Clearly, your first priority, and reasonably so, would be you want a reliable system. But the notice provisions have a balancing for the parties that do them more than just I'm not making money, I want to go away. They reflect a combination of considerations of labor contracts, complicated labor contracts. The announcements in some cases can trigger, depending on the nature of the owner, can trigger calls on indentures and violation of indenture conditions that could put facilities into financial default. They can trigger potential litigation, in at least one case I'm aware of, on fuel supply arrangements, must-takes, and what constitutes force majeure.

There are very, very complicated business -- you know, these are big assets that you're saying no to, not happily presumably, and some of the things are not fully reversible, and some of them may be irreversible. And so timing, however you figure it out, looks different from somebody who wants to be on the reliability side of things versus somebody who has maybe 20 triggers in front of him that go off when he pulls the plug.

It's keeping an eye to that balance is the essence of what the debate is, I think, in terms of somebody says, I want a lot more notice -- which is fair on the reliability side. Somebody says, you know, I'd like to wait till the very last minute, because I may not have to deal with all of these issues, okay. That all these issues side of things, I don't think has gotten fully developed in front of the Commission, that I'm aware of.

COMMISSIONER CLARK: Thank you. And thanks for keeping me out of trouble with my staff on the ex parte stuff. I'm just outside of kicking range, which I'm usually not in a meeting.

(Laughter.)

CHAIRMAN WELLINGHOFF: I know we are all hungry, and I'm not going to try to take up too much time, but I do have questions I think for each one of the panelists, and sort of an order in the order that I read them, with the exception of Roy. Roy, yours was perfect. I didn't have any questions for you.

(Laughter.)

CHAIRMAN WELLINGHOFF: Your testimony was just perfect, but otherwise I'm going to sort of go down the line here. As I do that, though, if anybody else wants to comment on the responses, feel free to do that as well. But we're going to try to hopefully get us all to lunch in a reasonable time here.

Dan, let me start with you. You talk about, on page 7 of your testimony, you say: "Capacity markets should not be used to meet off-peak needs or ramping rates." Let me challenge that for a little bit.

My concern is, how are we going to insure that, three years hence, say, in the PJM market or another market we might have, a forward capacity market -- how are we going to insure that we have the capacity or the resources available, necessary to meet the needs of the system? The needs of the system I see are not only peak, but also things like, you know, too much wind coming in that we have to absorb in the mornings, early morning, or the rapid ramp rates we may need to help meet the DUC curve.

There's a DUC curve in California. I don't know if you're all aware, this curve the CAISO has created. We have all the solar coming in that reduces peak, then how we meet the ramp rates when the ramps are required.

Do you see those kind of products as things that should be taken care of outside of capacity markets? Just comment on that, please.

MR. CURRAN: I think to that last point, the simple answer is yes, we do. When we thought about this, I think we've tried to start with, what is the goal of the capacity markets? And I think we've talked about that a fair amount. But the main goal is insuring resource adequacy.

If you start from there, the question begs, can you do more with these capacity markets? And then, if you do, if you try to do more in these markets, if you try to provide things like ramping, will you corrode the ability to serve the primary purpose? We feel that that is a very real possibility; that if we ask too much of these markets, if we try to have them be sort of a solution for a variety of products, it's been difficult enough to get to a point where these capacity markets, we think, are effectively working for their primary purpose. You know, it's been a lot of hard work.

We feel that focusing on the energy markets, focusing on the ancillary services markets, that's the appropriate forum for this. And the reason for that is that, if you're looking at the times here that we're talking about, things like ramping, things like flexibility with new renewables -- those are events that happen on short time scales, days, minutes and weeks. That's what the energy and the ancillary services markets were meant to address. Capacity is a much longer-term view.

I think what's critical is to try to make sure, you know, how can we feel confident that those resources will be there, which I think is a very fair question. I think it comes down to having very clear rules in the energy and ancillary services markets to allow investors the ability to properly forecast what can they earn.

We think that the capacity markets will insure that the resources, that the amount of resources that we need will be built, and we think that if we have clarity, transparency in the energy and ancillary services markets of how they'll address these problems, that the right resources will be built.

CHAIRMAN WELLINGHOFF: Okay, fair enough, although I'm not sure I completely agree. I mean, I'm still concerned about how do you insure that enough fast ramping capability shows up three years from now or whatever.

In any case, Lee, let me go to you. You had great testimony as well, and some very candid testimony. I appreciated some of your remarks. Specifically, on page 6, you said that "The ISO is not interested in common-sense reforms to its capacity markets."

(Laughter.)

CHAIRMAN WELLINGHOFF: Looking for a candid response.

MR. DAVIS: I wasn't discussing the MISO, either, in that.

(Laughter.)

CHAIRMAN WELLINGHOFF: And let me clarify that. To the extent that we're talking about these three markets, and we have ideas of them being applicable to other markets, I have no problem discussing that. I think that's perfectly within the purview of our discussion here.

If MISO or CAISO or SPP -- I think that's perfectly acceptable. But tell me why you believe this about ISO New England. Why is it broken? How do we fix it?

MR. DAVIS: Well, I must say that the first panel was an interesting panel for me in that regard, in that we have two other markets in the east region which I've operated in that actually are addressing that problem. And as you look at scarcity pricing -- and we saw a lot of scarcity pricing this year in New York and PJM, and we had units that were able to see that and participate in it, and our fleet performance was very, very good during that. So we were able to actually experience it and make profit off of it.

The idea of having a market mechanism built into the capacity payments, where you're actually incentivizing energy-type performance, it should just be in the energy market. Let's reform the right market in regards to what we're trying to incentivize in New England. We're not opposed to having better performance in New England at all, it's just where does it fit the best. And we believe it fits the best in the energy markets rather than the capacity markets.

CHAIRMAN WELLINGHOFF: What's the best way to get that reform moving forward in New England?

MR. DAVIS: You know, I think on the capacity side, one of the issues that was brought up was the ability to procure fuel. You know, are we covering our fuel costs, and things like that. You know, we cover our fuel costs in PJM and New York with the current capacity market now as it is.

What I would suggest is, on the capacity side in New England, let's get the demand curve and the slope set right first. Let's move into the energy markets and make sure that we're incentivizing the proper performance in the energy markets.

I will tell you, New England actually has mechanisms for ramp rates and things like that that we can take advantage of now. I'm not sure that there needs to be a complete overhaul of the capacity markets to achieve this. I think we should focus on, you know, adding the elements to the energy market that actually gets the ISO what it wants.

CHAIRMAN WELLINGHOFF: You also indicated that VCS, the company you've recently purchased, is exiting the capacity market in the northeast. Why is that?

MR. DAVIS: I'm sorry?

CHAIRMAN WELLINGHOFF: Why is it exiting the capacity market in the northeast?

MR. DAVIS: I don't believe we're exiting the capacity market in the northeast. You know, VCS is actually participating extremely vibrantly in the markets. You look at New York and PJM in particular, VCS has been a big player in the capacity markets, and it's been able to benefit from that participation as well.

CHAIRMAN WELLINGHOFF: Okay.

MR. DAVIS: I hope that I didn't have a topographical error.

CHAIRMAN WELLINGHOFF: They're exiting ISO New England, aren't they? That's what I --

MR. DAVIS: Oh, yes.

CHAIRMAN WELLINGHOFF: Why is that?

MR. DAVIS: As we look at the capacity markets in ISO New England, to be honest with you, the performance initiative that's going on now, we just feel that it's too risky for us to be able to participate as a generator. And on the demand response side, the risk is there as well.

CHAIRMAN WELLINGHOFF: Overall, would you recommend that the types of structures that are contained in the PJM market may be looked at, in part, as best practices that could be spread to other ISOs?

MR. DAVIS: Yes. I think PJM has a very stable market. You know, best practices-wise, I think that other markets can benefit from it. I must share the opinion on

New York. As some of the other speakers on this panel, I also believe New York is relatively stable as well. We've seen entry and exit in the New York market even without a three-year look forward piece in it, and we haven't seen huge price variances in the New York market. We've been able to get new capacity built, and we've been able to -- in fact, NRG has actually exited with one of its units in that capacity market as well.

CHAIRMAN WELLINGHOFF: Thank you, Lee.

Julien, expand on the ideas for flexibility procurements you talked about. Should capacity auctions recognize it and pay for the value of flexibility?

MR. DUMOULIN-SMITH: Absolutely. It would seem, if flexibility is a true reliability characteristic that you in theory need, then why not recognize it through an additional supplementary product? I suppose this could be summarized by saying, it's akin somewhat to limited demand response.

I recognize that implementation of this kind of a message is challenging fundamentally. But it would appear somewhat necessary in markets, in particular California, where status quo you will continue to see significant retirement of generation prospectively that in theory one would require for flexible needs.

So it doesn't necessarily relate directly to the northeast markets. But it would seem like an absolute must in California. Thinking prospectively again to those kind of penetration rates in the northeast, one would think you would want to go down this path. I would caution you, to the extent to which if you were to procure these kinds of elements, this would again kind of exacerbate the proclivity in the market towards gas. I would just be cognizant of that.

CHAIRMAN WELLINGHOFF: Overall, are you recommending uniform capacity design across markets?

MR. DUMOULIN-SMITH: I would argue, kind of consistent with some of the other statements, that PJM does represent the vast majority of best practices here. So ultimately, to that extent, if you're on the white side of the black and white that I alluded to previously, then truly structured fundamentals should apply. An ISO such as PJM does represent to the best extent those fundamentals.

CHAIRMAN WELLINGHOFF: Thank you, Julien.

James, I had one question. On your last page, you had that idea there that I want to just explore a little bit to try and understand. You talked about there should be some accommodation for certain locations where there is constraint and they can't build. How are we going to decide that? What about demand response? What about self-generation or distributed generation or other assets? Do we have to also exclude all those from being capable of being expanded in that area as well, and who's going to decide, and how do we go in and do it? I'm not quite sure how it all gets done.

MR. JABLONSKI: Well, I cannot give you an airtight, perfect answer or idea or direction. But the genesis of the idea is that what the market is seeming to dictate in LDAs, at $245 a megawatt day, is that something is needed there. But if you look on the ground there, that's not going to happen. It's not very likely at all to happen. Even getting transmission there is not.

It's relatively -- some of these LDAs are small enough where you can identify the limitations in terms of space and other barriers that may stand in the way. We went through a long process to figure out -- and I'm not sure anybody knew right off the bat -- the verification of DR, et cetera. So there may be a way.

And as I also said, I'm certainly not wanting to further complicate these complicated markets. But I think it's well worth it, because there's no point in having people, LSEs and their end-use customers, paying for something that really doesn't have much of a chance to be built.

As I said, if we could figure out a way to verify and everything with the DR, we can work out a way to do this.

CHAIRMAN WELLINGHOFF: I agree with you. We shouldn't unnecessarily require some group of people to pay for something that they can't ultimately choose the end result.

MR. JABLONSKI: You know, I mentioned some mitigation of the price, reducing of the price, because in that LDA, the price would be higher, even though things can't be built there. There could be some factor again developed. I don't have a specific idea or approach. It just seems again a logical thing to consider.

CHAIRMAN WELLINGHOFF: Thank you, James.

MR. JABLONSKI: You're welcome.

CHAIRMAN WELLINGHOFF: All right.

Richard, the question I had for you is again sort of like I've asked a number of the other commenters. You seem to allude to it some in your testimony on page 4.

Would you recommend standardizing capacity markets?

MR. MILLER: Yes. We do think some minimum level of standardization would be appropriate, and we wouldn't specify the kind of generic action that might be appropriate. I will just note, even though in my statement I referred to making a rulemaking, my company has also in the past noted taking the broader regional markets initiative and potentially expanding it to capacity markets.

CHAIRMAN WELLINGHOFF: Thank you. Last set of questions, Todd.

On page 3, you recommended that FERC investigate reducing or phasing out all reduced DR capacity resources. What's behind that? What's your thinking?

MR. SNITCHLER: I think that points back to one of my prior comments about looking at how we're treating the different products, offerings, and also how they're being compensated. If we're going to offer compensation of products that aren't iron in the ground of the same value as products that are, then there ought to be some equivalency with regard to their availability, the fact that they are deliverable.

Some of these limited products have a certain degree of flexibility that's not afforded to a provider that's iron in the ground, that then has to run. So if we're going to look to try to treat resources in an equal fashion, then we ought to perhaps limit the number of resources that are contemplated. Then I think it would make it easier for you to determine what the appropriate amount of compensation would be.

And so, I think taking that step back away from that type of product would allow you to more definitively state what value the standard product would then be worth.

CHAIRMAN WELLINGHOFF: As I understand it, from the perspective of reliability -- and I think Andy Ott testified to it this morning -- DR actually comes out better than generation, from a statistical standpoint. 95-plus percent of generation is below that, I guess.

MR. SNITCHLER: Sure. I'm from Missouri on this, and so I say, show me. And they've been able to do that thus far. But I still have, as the reliability point person in our state, I have concerns about what may be available three years from now, and where it's located. And the sizeable increase in the amount of DR that has arrived in PJM over the last three base residual auctions certainly causes me to say I'm hopeful and optimistic, and thus far it's been able to deliver. But at the end of the day, you ultimately still need to have that generation that's there to deliver the electrons when they're needed.

CHAIRMAN WELLINGHOFF: You also talked about DR should be physically on par with generation. You would agree with that?

MR. SNITCHLER: I think that's again how we want to classify how we're treating these resources, and making sure that you can have it delivered. One of the issues that we have experienced, and thus far we have been able to avoid any problems, is not knowing where these resources are located. I know where my generating stations are located, but I don't know where these DR resources come from. And if I have a problem in the eastern part or the AFTI Zone, but my DR is located in an area that can't be delivered, that causes us some consternation.

So, it's again trying to insure that products that are projected to be able to deliver three years from now will actually be able to be delivered. And I think this is one of the steps that we can use in order to make that, help give me more comfort that it's going to actually occur.

CHAIRMAN WELLINGHOFF: Thank you. Great.

I think we're, hopefully, ready for lunch. Thank you.

MR. DENNIS: Thank you everyone. We'll return and begin at 1:30 promptly.

(Whereupon, at 12:40 p.m., the technical conference was recessed, to reconvene at 1:35 p.m., this same day.)

AFTERNOON SESSION

(1:35 p.m.)

MR. DENNIS: Folks, if we could go ahead and get started, please?

(Pause.)

Thanks very much. We're about ready to start panel 3. Welcome back. Thanks for being prompt.

Our third panel is about to kick off here. Our panelists for this panel are: Jeffrey Bentz from the New England States Committee on Electricity; Robert Erwin, from the Maryland Public Service Commission; James Holodak, National Grid; Judith Judson, Electricity Storage Association; Shahid Malik, PSEG Energy Resources and Trade; William Massey, COMPETE Coalition; John Moore, The Sustainable FERC Project; and Ed Tatum, Old Dominion Electric Cooperative.

I will turn it to Commissioner LaFleur to start.

COMMISSIONER LA FLEUR: Welcome back, everyone, as we combat the normal post-lunch lull in these things. We chose one of the most provocative topics to get everyone back in the floor, and that's the intersection between state, federal and local policy initiatives in capacity markets.

Obviously, the central concept of a capacity market is a call on future resources under a single pricing concept, where you use a single auction to make sure you have enough forward reliability resources for resource adequacy. Right now, 29 states and the District of Columbia specifically mandate that a percentage of energy purchases, generally escalating over time, be a particular renewable technology. And there have been calls, most recently from Senator Market, for federal renewable portfolio standards.

Obviously, the concept of choosing a defined resource is directly in tension or in conflict with the concept of a market doing a resource-neutral procurement. So that's what I'm very interested in exploring in this panel.

Several of the pieces of testimony that were pre-submitted, several witnesses argued for that one way to define -- excuse me, one way to accommodate for example state policy choices is to redesign the capacity markets into tranches, where you have like maybe a baseload tranche and a green tranche and a ramping tranche and so forth. It's something that was called for in some of the testimony we got. Or, other ways to somehow take the renewable purchases out of the capacity market and run the capacity market without it.

I'm very interested in people's views on that. What's that likely to do to the core purposes of the capacity market, for price formation, for reliability? At what point are we still running a market, or are we doing integrated resource management with RFPs, and is the capacity market going to be durable in that kind of an environment?

I want to invite the ISOs who are sitting here to still participate if they have comments after we hear from you. So I'm sure that will be my only question, because that will take awhile. Thank you.

Who'd like to start? How about Mr. Malik, who's leaning forward?

MR. MALIK: Thank you, Commissioner. Thank you very much for inviting us today for what's proven to be a very interesting day so far.

We think there are legitimate reasons for states to be involved with respect to promoting some of their policies, for example renewables. And various ISOs, like PJM, for example, have evolved over the years to promote the introduction of renewables, such as solar and wind. And I think they've done a very good job in allowing those resources to come in.

But I think we should also hearken back to one of the principle reasons for having a capacity construct. It's twofold: it's for reliability and resource adequacy. And we do feel that trying to introduce a lot of policies through the capacity market may, at the end of the day, make it so complex that it becomes self-defeating.

So in principle, the way the auction system works right now, for example in PJM, works very well. We believe, in fact, the capacity market as laid out within that ISO has become de facto the gold standard for U.S. capacity markets. But by the same token, we should allow states, where necessary, to have their legitimate policy initiatives.

One thing I would say, though, with respect to those states putting in some of those initiatives. We believe that the jurisdiction of power market prices is something that should be jurisdicted by FERC and not by the states. And so as they go about putting in these policy initiatives, then they should take great care not to influence the price of power, which therefore would then affect the price of capacity and make it very hard for companies like ours to invest with certainty in the long term.

COMMISSIONER LA FLEUR: If I understand, in PJM there are the exemptions for certain renewable technologies. And with the sloped demand curve, they more or less accommodate that. But at some point, at what point can you not even accommodate it that way? I mean, if we had 40 percent renewables?

MR. MALIK: That's a great question, and I believe at some point there will be saturation, just as we believe right now, for example, demand response is coming to a level where it probably is rather saturated for the reliability that it provides to the grid. So I think it depends on the location of where those renewables are. I think the locational aspect of these markets is very important, and the more ability we have to designate certain LDAs, for example, as areas where they might be saturated with renewables, versus areas that are not saturated, I think that's a standard that we need to develop as a network.

COMMISSIONER LA FLEUR: I was referring to, if there's a certain amount, how much does it affect the price or suppress the price? But I'll move on to Mr. Tatum.

MR. TATUM: Commissioner, thank you. Ed Tatum with Old Dominion. I want to thank you all for the opportunity to come back, and also thank Andy Ott, because he reminded me that we were here before. I sort of went back and looked at my comments from seven or eight years ago, which was, "Please, let's not do this."

(Laughter.)

MR. TATUM: And throughout, Old Dominion has been able to work through this settlement process as well as the stakeholder process to come up with a workable construct.

With regard to tranches, which I think is where you're going with this, we like the idea of keeping it simple. We heard from the first panel today a lot of comments about a market that informs and then supports bilaterals. And if we're talking about markets, then I think that's where we should be going with this.

We already have a fairly complex construct with RPM. I was thinking, as a visual aid, I could bring all the rules. But time was pressing. As we get more complex with it, it's going to be harder to adjust to changes. It's going to be more difficult to incorporate emerging technologies. It's going to be more difficult to understand what a changing resource mix would be.

So if we're thinking about what we need to do as a tune-up, and how's the cholesterol looking, I would suggest that we keep one word in mind -- and it's not plastics, it's residual. This is a residual market. It's been one, and that's how we originally set it up. We did not design RPM to be the end-all and be-all. In fact, we're very clear it was not holistic, and that was how we set it up. So I would imagine a good path forward would be to continue on that.

COMMISSIONER LA FLEUR: So you would allow people to do things bilaterally, and just have this as an optional, extra market?

MR. TATUM: I think that's the right way to go. I think that that is the sweet spot, if you will, and we actually did indeed initially set that up in the original 2006 settlement.

Now, I heard a lot of folks on the previous panel talk about compromises. Well, I think compromise is a good thing, especially when you're marrying a theory of economics to the practical realities of the grid, and the number of different players and business models that come through there. And we came up with something that was indeed workable, but a major component of that original construct was: self-supply would clear.

There was a mechanism in there whereby, if the price was affected, that we'd be able to adjust it. And then both buyers and sellers would bear some of the responsibility for that, and our friends at the states had an ability, based upon reliability issues, if they needed, to move forward as well. That was residual to me.

Thank you.

COMMISSIONER LA FLEUR: Thank you. Mr. Massey?

MR. MASSEY: Thank you.

COMMISSIONER LA FLEUR: I'm sorry. Chairman Massey.

MR. MASSEY: Thank you, Commissioner. As I always say, it was one heck of a weekend.

(Laughter.)

MR. MASSEY: I think it's a very good question.

I'm representing the COMPETE Coalition, with 730 members, very diverse, generators, customers, demand response providers, technology companies, and others. So once we drop down from 30,000 feet, we don't agree on everything.

But one thing the coalition does agree on is the value of the existing capacity markets. I mean, they happen to be working. They are keeping the lights on. And as you heard from the first panel, they are basically well-structured. Obviously, they can be improved. But I think changing them fundamentally is not what we would like to see.

I like the concept of simplicity. One of the beautiful things about it is that a full range of resources can now participate. Demand response, we've seen a lot of it. Efficiency, generation, renewables -- everything can get in there and participate in the market under basically the same rules, and we think that is a good construct that the Commission ought to stick with.

COMMISSIONER LA FLEUR: Bill, would you raise the renewables -- like in New England, where they're not clearing out of the market, and just say, do that to the side, and we'll leave the market to market?

MR. MASSEY: Well, we think that all ought to be invited into the marketplace.

COMMISSIONER LA FLEUR: I don't -- they can bid, but if they don't clear, they don't have any exemption to exempt the minimum offer price rule.

MR. MASSEY: We have not had an internal debate on your order on the New England program, and so I'm not here with a specific proposal. But I can say as a general matter, the broader the market, the more entrants that there are with resources being treated basically the same, is what we think is the fairest and what we think will provide the regional price signal. There's really nobody else out there that's concerned about the regional price signal but you guys. Simplicity, clearing the way it does not, we think is the way to go.

COMMISSIONER LA FLEUR: Thank you. Mr. Moore?

MR. MOORE: Thanks, Commissioner LaFleur.

On behalf of The Sustainable FERC Project, we're very happy to be here. We represent a coalition of environmental and clean energy groups from around the country, and capacity markets have been an increasing area of focus for us, both offensively -- in terms of how can it facilitate new resources in the market -- and also defensively, in terms of what capacity markets, what kinds of barriers markets can erect to resources.

We think that it's a complicated question, reflecting I think an increasingly complicated grid. Renewable energy standards are a primary driver, but not the only driver, for increasing diversification of the grid: the production tax credit, a large amount of distributed generation, much of which is behind the meter, will be affecting peak load and overall energy demand.

Other considerations: I think in our comments we really called out the effects of energy efficiency portfolio standards and wanting to get them into the market as well. So I think that from where we stand, one size doesn't fit all. I think the experience in California, where they're going with increasing levels of renewables, is to some extent a long-term forecast of what could happen in the eastern RTOs, where we think that eventually we'll get to 50 percent renewables plus energy efficiency, and the grid ought to plan for that.

I think your answer has both short-term and longer-term components. We believe, we agree with PJM to an extent, that intent is very important when it comes to looking at minimum offers, applying the MOPR. We do not believe that state renewable energy resources, or for that matter other state-driven resources, ought to be subject to the MOPR.

We understand the challenges with it. But the reality is, we don't think it's quite as black and white a situation as, you know, others might think; that the states have a continuing role, and the federal government, through future carbon policies which are coming down now from U.S. EPA, will also affect the markets.

So we would say, tranches might work. Other, longer-term vehicles for operating reserves or flexibility resources -- you're going to hear a lot from Mr. Hogan's regulatory systems project on our next panel on this. But we think one size doesn't fit all, and we're also not convinced that the energy and ancillary services market may be sufficient to drive the investment in the newer, flexible resources we think are necessary.

COMMISSIONER LA FLEUR: Thank you. In view of the time, I'm going to keep moving through the speakers, through Judith, James, and then I'll let Mr. Ethier have thee last word and turn it over to my colleagues.

MS. JUDSON: Thank you, Commissioner LaFleur, and thank you to FERC for inviting the Electricity Storage Association to participate in today's panel. I'm here representing the Electricity Storage Association.

So in getting at your question, I first want to say that first and foremost, there are new storage technologies that can play a role in resource adequacy and insuring reliability, both for the current grid and for the grid of the future. To date, there isn't the ability in many markets for storage to participate in the capacity markets. Tomorrow there's a vote in PJM to start the stakeholder process, so we'll see how that goes.

In New York, there is a four-hour, energy-limited resource that could potentially qualify under, and the ISO New England limit's not clear where storage fits into capacity. So first and foremost, insuring that the existing markets can accommodate these technologies.

Storage resources have the unique ability to provide peak power using low-cost off-peak power. When I first started working on capacity markets, it was about eight years ago. We were here in this room at FERC. I was a commissioner in Massachusetts, and the thing I kept hearing over and over again was, we need to make sure we have adequate generation to meet peak, because electricity needs to be supplied and consumed at the same time.

From that, you think: well, what if we had storage? Storage can provide a lot of value to the grid, and there's been huge advancement since that time in storage resources.

Now, to get to your question specifically about tranches and different capabilities, what we're seeing right now is in markets such as California, where they're looking at a 33 percent renewables mandate, they're creating a flexible resource adequacy product, and that's to procure resources that can provide regulation, load following and ramping. Storage is very able to respond very quickly to ramp within seconds. If that capability is needed, and it looks like it will be needed if you reach those levels of renewables, that capability and that operational characteristic should be valued in the capacity markets to insure that there are enough resources to provide those services.

COMMISSIONER LA FLEUR: Is it significant to be in a capacity market rather than a forward-reserve market, or in ancillary services?

MS. JUDSON: That's a great question. It's possible a forward reserve market could work. The one thing that we're finding is, we've had advances in opening up energy and ancillary services markets to storage. And we're very thankful for the Commission's Order No. 755.

The challenge, though, is these are resources. They're steel in the ground, and these markets are designed for variable cost recovery. Just like every other resource, storage needs fixed cost recovery to get traditional financing.

So the capacity component, we believe, is necessary in addition to the energy and ancillary services market piece.

COMMISSIONER LA FLEUR: Thank you. James, and then Mr. Ethier.

MR. HOLODAK: Good afternoon, and thank you for the opportunity to speak.

I represent National Grid. Although we're not a vertically-integrated utility, we do have transmission electric distribution and gas distribution and generation throughout our various corporate entities.

One of the pressures that we always see is how to balance costs most effectively for our customers. There's a lot of constraints, a lot of build pressures that customers see. Renewable power is certainly one of them, and to the extent that we've got RPS requirements from the individual states that aren't necessarily handled through the wholesale market, we're pretty concerned about that. Rather than having the onus on the distribution utility entering into long-term contracts with renewable suppliers, and then trying to have them bid into the market, clearing or not clearing, whether they can get credit back to the customer base load -- you know, I think as an idea, a tranche is an excellent idea.

When we talk about exemptions to mitigation, to the local rules, the more I hear of exemptions, the less I think that we're satisfying the wholesale market. We're getting further and further away, the more exemptions that we apply. We think that the market might not have been set up correctly in the first place, when you talk about resource adequacy being completely independent in a blind eye. I'm blind to what particular type of generation it is.

You know, we get very concerned about fuel diversity. We've got the issue in New England about gas-electric interdependency, and a lot of generators switching over to gas, and having to satisfy that requirement as well.

So the idea of tranches might be an excellent one -- either that, or some form of attribute pricing in the market as well. So when we talk about fast ramp capability, black start capability, we could have environmental capability. I mean, it's not quite -- we're not proposing a carbon tax or something like that, but paying for an attribute that's important for the region or for the country is a viable alternative to that.

The idea of tranches also might work. The only issue that you have with tranches is the more you try to break it down -- we're not, certainly, proposing integrated resource planning again. But the more tranches you have, you know, you talk about what regions do they need to be in? Are they zonally constrained? How do you handle that?

If you have a more robust transmission system throughout -- both New York and New England actually satisfy that -- that may be a way to be an enabler for those. There's been a lot of transmission expansion done in New England compared to New York. There's a lot less congestion. In fact, congestion is nearly relieved completely in New England. No RMR contracts.

Transmission planning and build-out in New York is a lot more difficult. To the extent that we had done more up front, maybe we could have avoided a new capacity zone. But the idea of tranches would certainly be enabled by a stronger and more robust transmission system.

COMMISSIONER LA FLEUR: Thank you. I share your observation about the potential complexity. This was part of my question.

And I may give Mr. Ethier the last word on this one.

MR. ETHIER: Thanks for the opportunity.

Just a couple observations about tranches from an ISO that, about a year and a half ago, actually publicly considered this idea and then sort of moved past it, I guess. First, I think it's important to be clear about what people's goals are when they talk about tranches. It's one thing if you're saying, we think we need to acquire resources with characteristics that the market wouldn't otherwise provide, versus this is the way to price discriminate and to select who gets paid more and who gets paid less. So I think you need to go into it with at least knowing what your goal is.

Now, assuming it's the former goal, which is: we're worried the market on its own, as currently constructed, isn't going to provide ramping resources, fast-start resource; I don't think tranches are a substitute for more general resource performance. 2000 megawatts of ramping capability is not going to solve our 8000 megawatts of gas units offline because they don't have fuel problem.

Third, I would argue that, at least in New England, we've had excellent success with renewable portfolio standards and RECs. They have gotten lots of resources built in New England from what we can tell. The market monitor does financial calculations for new entry tests, and those revenues make a big difference in whether those resources are viable or not in our market. Just having dealt with a six-state ISO, the idea that we would move from a system where they each get to decide what's renewable, how much that's worth, to one where we're forced to coordinate all six states, I think I like the system where they each get to chose, honestly.

And then third, sort of at the more technical level, I guess my belief is that tranches are not necessary to get us the operational characteristics we need. However, I'm happy to engage in that discussion in sort of a rigorous way, but I think you really all need to be -- I think the discussion needs to be predicated on the right goals to start with, and then we can have an open discussion about whether short-term markets will incent this behavior or not.

COMMISSIONER LA FLEUR: Thank you very much, all of you. I'm going to turn it over to Commissioner Clark.

COMMISSIONER CLARK: Thank you.

I just wanted to follow up a little bit on, Cheryl, your discussion with Judith on the storage capabilities. Because that was a question that I had. It intrigued me as well.

But I'd be interested in hearing from the other panelists about their views on the role of storage and the appropriateness of storage in terms of participating in capacity markets, especially for their abilities to perhaps commit to providing energy during peak periods.

Go ahead.

MR. TATUM: Ed Tatum with Old Dominion Electric Cooperative. There definitely is a role for storage. We've had storage for years via pump-storage hydro, and that's worked pretty well. But the thing we're talking about today is a resource adequacy constraint, and in PJM we're looking at the peak load obligation of an LSE -- I'm sorry, a load-serving entity. And the load-serving entity's peak load obligation is based upon the top five hours on non-consecutive days.

That's what we're talking about, resource adequacy constraints. We're not talking about operational reserves. As an electrical engineer, I try to differentiate between those. So when I think of storage and opportunities, I think of energy and I think of the ancillary services and other operational performance opportunities.

That's one of the fears I get into as we try to put more into this resource adequacy bucket, if you will. I think there is a role for storage. I think that Judith raises a great point about some of the capital investment they have to make. So that is something I think we should work on. I don't believe this is the forum.

COMMISSIONER CLARK: Others want to chime in? Mr. Moore?

MR. MOORE: Thanks, Commissioner Clark.

We think storage has a role. We support PJM's effort to include storage, the proposed development of including storage in the capacity market. And I think there are lots of different types of energy storage available for the short term and the long term, and I think Ed's comment does once again bring us back to what is the purpose of the capacity market, what are the primary purposes. If it's just for serving peak load during those five hottest days of the summer, that's one thing. Again, I think what we're seeing in other markets is that there is an evolution.

I think that we see storage as a useful way to integrate renewable energy when done right. Proposals I've seen, for example, in one of the other RTOs that shall not be named to bring significant hydro into the United States to help balance out the variability actually in wind power -- actually, those studies don't show that it's actually very cost-effective to bring those large chunks of hydro in to balance out the winds, does not need it as much.

So, we think we like storage. We want to be careful about how we apply it as a cost effective way of integrating wind. It has a lot of other very valuable services, though, and we support including it in all the capacity markets as a resource.

COMMISSIONER CLARK: Thanks. Bill?

MR. MASSEY: Commissioner, we have not internally debated storage in capacity markets. We've had storage company members. We support storage. We do stand for the proposition of a big capacity market tent. The broader the range of resources that can participate and meet the standards, the better it is for a true price signal in that big market as long as you, with a good MOPR, protect against uneconomic entry. That is our perspective.

COMMISSIONER CLARK: Judith?

MS. JUDSON: Thank you.

If I can just follow up to that, I just want to add that, as mentioned earlier, there are many different storage technologies. And of course, there's been pumped hydro, and there's rules in place for pumped hydro. There just isn't a rule for other types of storage in many of the markets today.

But we're seeing more and more long-duration batteries, compressed air, other storage technologies that can provide peak power, and they do so with lower-cost off-peak power. To the extent that the goal of the capacity narket is to supply peak power, then at least define the rules and the requirements, and if storage has the capability, allow it to come into the market. We would advocate that there is that capability, and that capability is growing.

So these markets take time to have new changes integrated into them, and of course, where there's a forward capacity, that needs to start now so that you can be in an auction that applies three years from now. I would highly recommend that the market define the characteristics they're looking for, and then if storage has that capability, it can provide that. And of course, we think storage has a lot of other capabilities as well, but there are long-duration technologies that can provide cheap power.

COMMISSIONER CLARK: Thanks. Mr. Bentz?

MR. BENTZ: Thank you, Commissioner. I learned to turn on both mikes when the prior panel was here. I hope you can hear me okay.

Thank you for having us down. I think I'm just going to echo a lot of the comments of the other panelists. We haven't had probably very detailed discussions about storage. We've had some. I think that opening up the market to all aspects of capacity suppliers is important. We've seen some of these industries start out small and grow into large industries that have provided great benefits to the New England states.

I guess, since we are in a large discussion about where we are going with FCM markets in New England right now, defining what we need and then allowing those types of resources to come in and serve it will be important. So I think it's a little bit hard to answer the question, should they be in. I think anything that adds to the broad-based resources that can compete is always a good thing.

COMMISSIONER CLARK: And then one final question. Oh, go ahead.

MR. MUKERJI: A comment on storage. As Judith mentioned, as long as the storage can perform for four hours, New York ISO allows that. We have bump storage that participates in it, and hydro with pondage. Potentially, batteries and compressed air can also participate in that amount of storage.

One thing I just wanted to clarify, though. You had a comment on large hydro from Canada. We have an intertie with Canada, and we are using -- one of the things we did in the broader regional markets initiative is, increase the frequency of our schedule from one hour to every 15 minutes. That has really helped us, for a relatively modest investment in software, allows us to use the immense storage in Quebec to balance our intermittent wind in New York.

I know that Hydro Quebec does want to go down to five-minute scheduling, and we plan to do that in the future. So we've had a success story for relatively modest investment in software, to have access to a significant amount of storage from hydro.

COMMISSIONER CLARK: Thanks.

One last question. This is kind of a big one that gets to the heart of a lot of the consternation that we've had over the years, it seems like, with capacity markets. And I hearken back to Mr. Dumoulin-Smith's comments this morning. It's a black and white construct, and some just don't fit very well together.

When I've sometimes spoken around the country, the way I've put it is, once you pick a course as a state, whether it's as an integrated resource state or as a restructured state, you kind of need to stick with it. It's tough to smush some of these concepts together.

So my question is, with regard to accommodating state policies -- and understanding that states have specific reserved powers, and FERC and the federal government have specific reserved powers and things that we need to be looking over -- with any sense of specificity, do you have, if there was a change to be made to the markets that you're familiar with or you're working within, to as best we can accommodate both of those goals, that are sometimes in tension, what would that change be if you had to pick one or two?

I'll open the floor to whoever wants to take that one up. Jim?

MR. HOLODAK: The RPS requirements that we have in New England -- and I take Bob's point that New England is sometimes like herding a group of cats; you can't get anybody to agree on anything -- to the extent that they are able to push in a regional procurement, which is something they are working on, and get to an agreement on what a regional RPS requirement might look like, that would be a good thing.

Secondly, if there was a way then to accommodate that in the capacity markets, then what we're seeing with onshore wind energy is that the combination of energy production tax credits and the REC, they're getting to a point where they can clear the capacity markets. So I would look at that and say, if that is indeed the case, then maybe the wholesale markets can accommodate them without having the individual distribution company enter into long-term DPA contracts to finance those resources.

Now, it may be that the REC environment is too volatile to be able to finance off. But to the extent it was integrated more into the wholesale markets, maybe that could change. And if you had a REC for wind versus a REC for hydro versus a REC for solar, you know, getting back to sort of the specific attributes that the states are trying to solve for, if we could handle that in the market it would be much better from a utility standpoint than burdening the customers with long-term contracts.

COMMISSIONER CLARK: Mr. Bentz?

MR. BENTZ: Thank you, Commissioner.

First of all, we do continue to believe in these competitive markets in New England. But those markets are a means to an end, and they can't just be an end in and of itself.

To the question of, how can we marry the two -- and we heard a lot this morning about it's difficult; nobody's come up with an answer -- I agree with that. When the MOPR came out, we worked with a lot of people to try to figure out an answer to that question. And what we came up with was, an exemption.

To Commissioner LaFleur's earlier question, I kind of look at that as a little bit of a tranche. It's an exemption. We tried to narrowly tailor it to kind of balance the ability to have the states meet their needs without having as difficult or as material an effect on the market. I think that's the balance that we're with. We give an exemption, it does have some price suppression effects.

But I think it was Julien who said earlier, or Dr. Patton -- the benefits that the states are looking for are hard to be priced in. There are attributes that just can't be priced in. There are benefits for these resources getting the subsidies. So to that point, having them continue to stay outside of the market and essentially have a market that grows with excess capacity, I think, then starts to go against the sustainability of the market.

We heard a lot from the panelists this morning about, we need to have price scarcity. We need to have the right price signals. But over time, if you don't have an exemption, and these resources are just staying outside of the capacity markets, continuing to provide energy, I think at some point you continue to have a price concern on the energy side that we don't get the scarcity conditions that then drive the rest of the capacity market.

So I think by narrowly tailoring the exemptions to RPS standards that can be shown out into the future so that people can price that into their bids four or five years out, knowing what that exemption is and what limit it is going to be, I think would be helpful to the overall market.

COMMISSIONER CLARK: Ed?

MR. TATUM: Commissioner, thank you for that question. This is Ed Tatum with Old Dominion.

As far as things and opportunities in PJM, perhaps we should take a different look at the peak load obligation, and making sure that the LSEs really have a full and complete well-defined reliability-based criteria that they have to indeed meet, and then come up with some products that will fit that criteria. I think that's one opportunity.

I think another thing that I really would like to happen is, I would like us to stop looking behind every tree for that monopsony power bogeyman. In 2006, in the eleventh hour when we were negotiating this, our folks came back and told us, after Judge Brenner locked us in, that they were concerned about -- types of organization like the Old Dominion Electric Cooperative, exercising monopsony power. I said, "They think I'm going to do what?" It was incomprehensible. But nonetheless, we continued to work through this.

It's very, very difficult, as you have to think about intent. You have to think about incentive and ability. It's a very, very risky, risky business for someone to try to get in there and actually do something solely to tank that price. So that's another concern I have.

The last concern I have is getting the proper perspective of what we are indeed talking about. Panel 1 today talked about the long-term view, and net CONE over the long term. I'm an engineer, so I don't have the horsepower a lot of the other folks have, but I don't know that we've had the wrong results over the past few years. I don't know if we haven't solved the missing money. I worry that the missing money might now actually be coming out of my pocketbook --

(Laughter.)

MR. TATUM: -- because our net CONE has increased, almost doubled, since the time we actually put it in, and that has changed the shape of the curve.

So the simple answer is, I think we have a few things that we can tweak and look at. I think we need to get a perspective on the ability, intent and inspiration a buyer would have to exercise this power, and put that in the right perspective. I think there's plenty of room in the tent for RPS as well as states taking care of their own reliability criteria.

COMMISSIONER CLARK: Thanks. Bill?

MR. MASSEY: COMPETE as an organization is very concerned about uneconomic entry and price suppression with the capacity market. The first question if you're going to accommodate states is, okay, which states are you going to accommodate? You know, that's come up in your MOPR proceedings before. If New Jersey subsidizes generation, Maryland subsidizes generation, Pennsylvania intervenes and says, wait a minute. They're affecting prices in Pennsylvania as well.

This is a regional market with regional adequacy issues. In our view at COMPETE, you need a strong MOPR to insure that there's no uneconomic entry, and that's the way you ought to deal with this problem. Because otherwise, you end up in a position where you're trying to decide which state goals to accommodate, and you've got states that disagree strongly in the same region. So that's our message on this point.

COMMISSIONER CLARK: Thanks. Mr. Malik?

MR. MALIK: Thank you.

We completely agree with COMPETE on this issue. There are legitimate roles for states to play in promoting new technologies, for example, like solar, like wind, maybe even battery as well. But we believe that when it comes down to, you know, affecting the investment climate of new potential builds, new generation builds, states shouldn't have a role in setting market prices, wholesale prices for energy, nor wholesale prices for capacity.

We have a MOPR that has been, let's say, negotiated over the last few months at PJM. It seems to have made significant improvements. The change from net CONE of 90 percent to 100 percent, for example, we believe has been a good thing. But now it covers the entire RTO rather than just what were deemed to be constrained areas.

Then the competitive exemption, which we support, for legitimate policy reasons, and frankly we believe that the stakeholder process that we have engaged in and others have engaged in should be the vehicle for changes. In general, that has appeared to work pretty well. Occasionally we've had problems in getting them through the final regulatory approval, but in general that seems to have been a process that worked pretty well.

I think there is a legitimate role for states to play, but not one where they're able to affect market price, and therefore the future investment climate. PSEG, for one, was very actively looking at building a new power plant, and we turned down the opportunity because we were concerned that the impact of this subsidization the state was promoting would put us at a competitive disadvantage. So we decided not to build it.

COMMISSIONER CLARK: Thank you. John?

MR. MOORE: I agree with the first speaker, Jeffrey, that capacity markets should be a means to an end, not an end in themselves. And I feel like one additional point even could be worked on more in the mostly deregulated markets of the east, is more coordination with state planning. And I think the planning that takes account of these state actions needs to be fed into the resource adequacy/capacity markets in some way, so that you don't overprocure.

I think Order 1000 said, let's take public policy requirements into consideration in the planning process. I think a lot of those public policies that occur need also be reflected in, say, net resources that you're seeking through the capacity markets.

So, it's a hard question to bring the states together more in this process, but I think we're just going to be seeing a lot more of these state actions and drivers that result in more distributed generation, more behind-the-meter generation, more variable and intermittent resources that need to be reflected in the alternate capacity goals for the market without overbuilding.

COMMISSIONER CLARK: Thanks. Mr. Erwin, did you want to jump in?

MR. ERWIN: Thank you, Commissioner.

As a representative of the Maryland Public Service Commission, and keying off Mr. Jablonski, we are the problem. I need to start with the standard disclaimer that, while the written comments we filed were approved by the Commissioners, my comments here today are mine, and not necessarily that of the Commission.

The reality is, states are going to adopt public policies that will affect reliability, and they will affect prices in the capacity markets. That is going to happen, and there's nothing PJM or anybody else can do about it.

Maryland has enacted a very aggressive RPS standard, where we want 20 percent in Tier 1 by 2022. We have adopted strong energy efficiency statutes. We are instructed to reduce regular load by 10 percent by 2015, and peak load by 15 percent by 2015. Those things are going to affect the capacity markets, and they're going to affect reliability in Maryland.

Now, what can we do about it? The MOPR was originally put in to avoid use of market power. Every state is going to end up with its own unique market configuration. Maryland ordered new generation built, baseload gas plant, because we knew we were going to have a lot of renewables, and we needed that flexibility. 80 percent of our generation was either coal or nuclear. We needed something that could adapt to the renewables we knew were coming in our state.

Now, what to do about it. One, you could go back to the original deal, the settlement, that said state-sponsored exemption from MOPR is there as long as it's for reliability. That was not carte blanche to the states. I don't really fool myself to think that the Commission is going to do that now.

But one thing you could do is, get away from this irrebuttable presumption that whenever the states do this, we're doing it to tank capacity market prices. And that's really what PJM says, is that it's a state-sponsored exemption; you're doing it to affect prices and drop prices. And that simply is not true.

The Maryland statute says, when we issue an order, the court on appeal is to review that, not to substitute its judgment, but to say: does the record show there are facts to demonstrate that the Commission's decision was one which reasonable minds could reach based on the facts before it. PJM and FERC could say to states, if you had a project, and you can show us facts that you were doing it for reasons other than tanking market prices, you get an exemption from MOPR. Certainly we would support that kind of an approach.

Thank you.

COMMISSIONER CLARK: Ed, did you have one more?

I want to make sure --

MR. TATUM: I do, and I want to be very quick, and I appreciate the second bite at the apple here.

I just would like to comment that some of the answers you heard do a very nice job of framing really the choice this Commission is going to have to be thoughtful about. Do we want to have a capacity construct that is set up for a predetermined answer for a certain group of resources? And folks who know, who are a lot smarter than me, who know that the answer is wrong right now, based on maybe ten years?

Or, do you want to have something that's a little bit more narrow, as we started out with, it's residual, and as Dr. Patton was talking about this morning, informs the bilaterals? That's kind of just the juxtaposition of what I saw.

Thank you.

COMMISSIONER CLARK: Thanks, Edward.

COMMISSIONER NORRIS: To change gears a little bit here, I'm going to come back to a question the Chairman asked the last panel, and start with you, John.

You had mentioned in your testimony a discussion or concern about distributed generation, and whether the RTOs are properly accounting for that in their resource adequacy projections, and in fact may be overpurchasing resources.

Do you have additional ideas of how capacity markets can be made more transparent in order to accommodate these resources? We heard some answers this morning that that was being done. Is it a matter of transparency, or are they taking, properly accounting for it?

MR. MOORE: I think it's both. I think that actually, I thought what the RTO said this morning in the main was good news. We like the fact that ISO New England, in particular, has been looking at the distributed resources, the increasing levels of distributed resources in the system, and accounting for them.

What we would like to see is greater ease of aggregation for including them in the capacity market, because I don't think we're seeing a lot of them up here yet. We know in PJM, there are many hundreds of distributed resources that are in the interconnection queue now, and I don't know that they've really been aggregated yet and bid in significant quantities into the market.

I liked what we heard this morning in terms of receptiveness to including those distributed resources in the market. We think they deserve comparable treatment in the capacity market, just as they should be receiving comparable treatment for solutions to transmission planning problems. That's a connection again, the planning-capacity market connection. If you're using the capacity market to help solve transmission problems in a way, you want to see those resources at a very granular level, and you can do that through allowing them to participate in the market.

COMMISSIONER NORRIS: A little broader question, following up on some of your comments, John, and expanding them.

You mentioned the need to get more energy efficiency bid into the capacity markets. So we've got energy efficiency, distributed generation, demand response being treated differently in the different capacity markets, storage being treated differently in the different capacity markets. Yet, Bill, you said that simplicity is important here.

Are the characteristics unique enough in the different three RTOs that justify the vast differences of design elements, or is that outweighed by a more simplistic way for everyone to participate in the multiple markets by having more extreme lag or common design elements across all three RTOs? Anybody?

MR. MOORE: Can I just say, on the energy efficiency point, Commissioner, that we think some standardization is possible. We think that there ought to be more standard MMV protocols for different forms of commonly-used energy efficiency. We think that energy efficiency ought to be given credit for its full measure life to maximize its value.

So I think, in this case, in the case of energy efficiency and other resources as well, some of the distributed generation resources -- solar panels in particular -- I think you probably can come up with some common metrics that would help to expand their use in the markets. The MMV and measure life, I think, are two ones that we view that should be relatively similar unless there are very specific regional reasons. They ought to be similar.

MR. MALIK: Yes. At PSEG, we believe that there are more similarities between the different markets and products as well. We generally support regional approaches to markets, recognizing that there are some differences. But there are definitely certain elements that are present in all capacity markets, whether it's distributed generation or solar.

Locational design is important. Effective buyer-side mitigation is important. Measurement and verifications are important. So definitely we do agree that there are some instances where there can be some common themes throughout the various ISOs, and we would encourage that. It would help reduce the complexity of the markets and enable us to look at the northeast as one market, as opposed to multiple markets right now.

MR. MASSEY: I voted for standard market design.

(Laughter.)

COMMISSIONER NORRIS: I made sure I said "consistent" and not "standard."

(Laughter.)

MR. MASSEY: That was a huge success, I would say.

(Laughter.)

MR. MASSEY: It was the right thing to do.

But let me just say: either the Chairman or one of the Commissioners mentioned, let's take a look at best practices, and maybe think about whether there's a generic approach to some sort of best practices. I don't know about standardization, but you know, electricity is electricity. Perhaps there are regional differences. But there have to be some best practices that could likely be incorporated in all capacity markets.

MS. JUDSON: Thank you, Commissioner.

You mentioned in your question the different treatment for storage across different markets. So the one thing I would say is, a key element that needs to be in all markets is that we reduce barriers to entry for new technologies. How that's done may vary across the markets, but that key principle should be required or considered across all markets.

MR. HOLODAK: I agree with the comments of the other panelists. I think consistency across the region would be terrific.

One of the things that I get concerned about dealing with some of the demand-side resources, especially in New England -- they tend to want to play in the market when there's money to be had, but they're not really there for long-term commitment, necessarily. To the extent that they've got another business that they're in the business of running, you know, depending on the price signals, they're either in or they're out.

When you're comparing a demand-side resource to steel in the ground, I mean, you're trying to plan a system for the long term, and DR jumping in and out of the market seems to me not to be necessarily the best thing. If you can count on it, that's fine, but how do you count on a resource for a business that may not be in business in two or three years.

So it's just that consistency across the board needs to be had, but the consistency of DR also needs to get taken into account.

MR. TATUM: Commissioner, thanks. This is Ed Tatum of Old Dominion.

I think there's opportunities for consistency, I think, with Order 1000. You all have demonstrated that there's opportunities to try to get aligned with how we do some things.

One area to think about, I would hope, is again keeping in mind what we're trying to accomplish here. In PJM, we have top five hours, and that's how we're defining our peak load obligation for the resource adequacy constraint.

So if we have a group of products, there should be products that hopefully would have certain characteristics that would be able to meet that obligation. In PJM we have three flavors now of demand response. We have limited, extended and annual, and so we talk about six and ten hours' worth of performance over different time periods.

So if different types of resources can enter into that, and those are useful attributes for the overall holistic regional resource adequacy, then that could be an opportunity for standardization. But those relationships, I think, are important.

MR. MALIK: One other thing, slightly beyond the issue of distributed generation and demand response, is the issue of transmission planning and having some consistency across markets. I think if we could see some additional consistency between the way we plan for transmission and the way we plan for capacity, I think that would be very beneficial to the market.

So, for example, considering similar elements with respect to the demand forecasting, we recognize that transmission projects generally take longer than generation projects. But certainly, it's been relatively easier and preferred for some utilities in the past to build transmission rather than generation. And there may be a more effective solution than that.

CHAIRMAN WELLINGHOFF: Let me -- I've got some other questions, but let me just follow up on this line, because it's one of the most interesting things for me.

You know, we have multiple resources that potentially can bid in or are bidding in, in fact, in these different capacity markets that we're discussing here today. And we have this other resource called transmission, that doesn't bid in but it gets paid and compensated in a different way.

So I think this was discussed some in the last panel, but I'd certainly like your-all's comments. How do we rationalize this so that we have, you know, the demand response asset may have a financing window of three or four years. A generation asset may have a financing window of, you know, 20 years or more, as well as a transmission asset, and they may have different requirements for that financing and for that ability to, in fact, procure the asset and insure that it's reliable and available and there when needed.

So, how do we insure that we get the right mix of the least-cost assets in designing a capacity market, and also include the aspect of transmission as being one of the potential solutions? Just a simple question; anybody?

James?

MR. HOLODAK: I think it's a very valid point, Mr. Chair. One of the issues that we've seen operating in these markets, as a customer and as a transmission owner, is that transmission, especially in New England, is considered just a backstop. So if there's a capacity shortfall, the market's supposed to resolve that capacity shortfall.

But that doesn't mean that, through a new generator, that that shortfall is satisfied in the most cost-efficient way. We've had price separation in NEMA Boston, and then we've got a new generator that cleared at $1499 a kilowatt month for five years. The price separation there relative to the rest of ISO New England, that increase was about $250 million a year to customers, and we've got a potential transmission solution that is $200 million, and that could help satisfy and relieve that constraint.

We're not suggesting we compete eye-to-eye or toe-to-toe. But I think reviewing the transmission system and looking for the most cost-effective situation, the most cost-effective solution, as opposed to just being a backstop, would be a good thing for customers. It would relieve constraints and would likely reduce prices over the long run.

CHAIRMAN WELLINGHOFF: I agree, Jimmy. The question is how functionally you actually do that.

MR. HOLODAK: Good question.

(Laughter.)

MR. HOLODAK: Absent something like an IRP process, I mean, it's difficult.

CHAIRMAN WELLINGHOFF: Rana?

MR. MUKERJI: Transmission projects have to be controllable. Would you like high-voltage DC lines in New York to get capacity market payments?

CHAIRMAN WELLINGHOFF: I'm sorry? It has to be controllable to get capacity?

MR. MUKERJI: Capacity payments.

CHAIRMAN WELLINGHOFF: If you can control it like a DC line --

MR. MUKERJI: Like a DC line. So now, if you have a difference between nodal pricing and the energy market, and we have either reliability or economic planning to justify transmission when we have locational capacity markets and different prices in different locations.

Currently the DC lines and controllable lines can get the price difference. AC lines do not in our market.

Our market monitor, David Patton, has recommended that we look into that aspect of it, and that's something we can certainly do in the future.

CHAIRMAN WELLINGHOFF: So in essence, if you had an AC valve on a line, you might be able to then get a capacity payment for it.

MR. MUKERJI: Yes, between the nodal differences and capacity markets.

CHAIRMAN WELLINGHOFF: Interestingly enough, there are technologies that have come to FERC that have talked about putting in, functionally, in essence a valve on an AC line. So it's very interesting.

Edward?

MR. TATUM: Chairman Wellinghoff, thank you for that.

Eight years ago, when I came here, I asked you not to do this. But I also asked for one other thing, which was a very robust transmission system, which would be essential to supporting anything that we do. I think the Commission is to be commended for all the progress that's been made in that regard.

With regards to the idea of transmission having a bias or being able to trade it off for capacity, I'm having a hard time with that concept. If we're embarking upon competitive markets, we're going to fit lots of buyers and lots of sellers together. That's the facilitator. Transmission enables everybody to get on together, and it's something that's a very long-lived asset. It is something that is regionally planned.

We've turned over all the transmission planning to the regional transmission organizations. So my hope would be that we would be spending a little bit more time getting a wee bit more innovative with regard to the way we approach transmission planning in and of itself.

We've learned a lot over the past ten years, but the world has markedly changed. It used to be we did have resources that we would substitute for transmission at the very end of the line for voltage support or something like that. But resources are now competitive. So how do we have a transmission delivery system that accommodates a competitive grid?

So my suggestion would be, additional focus on opportunities for planning in the transmission grid that would focus more on capacity benefit, would relook at the benefits of economics for the energy market, and would be able to incorporate some of the energy-only technologies that we've talked about. That would be my suggestion to move forward.

CHAIRMAN WELLINGHOFF: Judith?

MS. JUDSON: Thank you, Chairman.

I don't want to get too far afield here, but you raised the issue of transmission, and one of the things for storage is the challenge of where does it fit in the puzzle. It's not perfectly generation. It's a net consumer. It can provide some of the capabilities of transmission, or allow for deferrals for different aspects to provide things like voltage support that were just mentioned.

So how you put that puzzle together from a broad standpoint of how capacity markets and transmission fit together I think is a huge challenge, and a hard question to answer. But certainly from a storage standpoint, insuring that the resource can be used in different applications across the spectrum as it's capable of doing is something we'd like to see continue to be explored.

CHAIRMAN WELLINGHOFF: Shahid?

MR. MALIK: Yes. You asked the $100 billion question, Chairman.

You know, first I'd like to commend the FERC on its transmission policies over the last few years. Clearly it was creating a huge build-out of transmission that's reduced local bottlenecks. If you look at, for example, the area where my company, PSEG, is located, in northern New Jersey, you'll see that we've spent upwards of $5 billion on transmission projects over the last few years. That will relieve that congestion that was there.

That's also facilitated new power plant development. And in fact, as part of what we've been able to do to reduce that bottleneck, there are three new plants being proposed to be built in northern New Jersey.

To complete what Mr. Jablonski was saying earlier on, there are three new plants, three new combined cycles, that are being built in northern New Jersey. So I think transmission policy is helping.

I think the question of this panel has been more about capacity markets. I think we need to transcend just capacity markets, with energy, ancillary reserves and transmission together. I believe that if you try and come up with the optimal solution for one and squeeze that balloon now, you're going to have a problem elsewhere.

So I would certainly urge the FERC to maybe expand the discussions that we're having and include those other areas, too.

CHAIRMAN WELLINGHOFF: Thank you. John?

MR. MOORE: Sure, Chairman.

One point of commonality, I think, among many of the environmental and clean energy groups and the generators who submitted comments is, more consideration of non-transmission alternatives, inclusion of them in the markets.

We tend to think of demand-side management and some of the suppliers think of generation, but we're both talking about non-wire solutions.

So that's one point of observation. I think, to get to the answer to your question, I think more granularity in the markets for all the demand-side resources, and non-wire solutions in general, would help. More granularity is better in terms of subzonal pricing.

You know, right now, to take one example, Commonwealth Edison has a tremendous amount of energy efficiency that it bids in and clears in the capacity market. I don't know that that energy efficiency in ComEd's large zone is deemed able to be deployed in any particular areas to relieve transmission constraints on the margin. I don't know if that's possible right now.

Even with PJM's relatively tight connection between planning and the market, I don't know that you're able to target it down to that level yet. So more granularity in the market would be helpful there.

CHAIRMAN WELLINGHOFF: Great. Anybody else?

(No response.)

CHAIRMAN WELLINGHOFF: Okay.

Let me go on to the next. Did you have a follow-up, Cheryl?

COMMISSIONER LA FLEUR: No, not to that question.

When you asked, anybody else, I thought you were asking us.

(Laughter.)

CHAIRMAN WELLINGHOFF: I have one other area I want to get into, and then we still have plenty of time, actually.

This goes to testimony, I think -- Robert, it was in your testimony. I found it very interesting, and I agreed with a number of recommendations there.

We talked about, in the previous panel, some of the positive things about PJM and its capacity market. And here you're recommending I think a number of suggested modifications, improvements. Just to paraphrase, I think the first one you indicated that RTOs and ISOs should break up the capacity bundle into more discrete segments that would result in more accurate price signals, was one suggestion. The second was compensation of capacity resources should vary to reflect the type and value of the capacity services provided in the markets. Third, that administrative rules, though necessary, shouldn't be used to establish arbitrary, unnecessary pricing floors or prevent price competition. And fourth, FERC should preserve the ability of sophisticated buyers and sellers to engage in mutually-beneficial long-term transactions.

I don't think I could disagree with any of them. The ultimate question always is, how do we get them done, I guess. What would you suggest as to how we, for example in PJM, move forward on working on these issues?

MR. ERWIN: To try to give you some concrete examples, Mr. Chairman, looking at recommendation number one, for example. PJM, both in 2006 and again in their recent written comments, said: we have a capacity market for two different purposes. One is to get existing generators to stick around and commit that I'll be there in three years, for reliability. I also want to send a signal to somebody to go build a brand-new power plant.

Now, the signals that you send for those two products, in just my common sense says, they're very different things. Should we be paying a single price for both of those? And my analysis seems to indicate that we may be overpaying generators to stick around, and we're underpaying enough to get new generation built.

So maybe, what we need to do is break those two things apart, have two separate auctions, let them bid, and find out what is the right price signal for each of those two products. Indeed, there could be a third product of an up-rate or expansion of existing plant that's not nearly as expensive as a brand-new plant. But it's more expensive than, just stick around.

So we need to think about: is a single price signal really going to work? One of the things -- the

Maryland Commission, like FERC, our job is to provide safe and reliable service at a just and reasonable rate. And one of the things that I find is often overlooked in this discussion of capacity markets is the just and reasonable rate piece. The assumption is, well, one price is going to be just and reasonable. I suggest to you that may not be true, and that needs to be rethought.

Number three, for example, goes directly to MOPR and CONE. You really do have to get those right, and if you arbitrarily say, the cost of financing is going to be X, as opposed to what is your cost of financing, you're going to mess up all the signals. So we need to get those correct.

Finally, what's the difference between a megawatt of capacity that Maryland generates and a megawatt of capacity from self-supply or from a vertically-integrated power plant? Those are all going to have exactly the same effect on capacity price. So why should we say, well, Maryland's megawatt's a bad megawatt, but those guys' megawatts are good megawatts? And that's what we're getting at at number four.

If we're going to allow bilateral contracting, a state contract for differences is no different than another form of bilateral contracting. Our contract for differences is essentially a hedge against the volatility of the capacity market. If you looked at that graph out in the hall, you see for eastern MAC, it's bouncing all over the place.

When the bankers came before the Maryland Commission, they testified there's no way I'm going to lend money on that price signal, and certainly not if it's only for one year.

CHAIRMAN WELLINGHOFF: Just to follow up with you, and then I've got a couple of hands up over here that I want to go to.

So, item number one, for example -- and again, I don't necessarily disagree that we can disaggregate more these different types of capacity, and we might get better results. But how would you then respond to people who might say, well, that just adds more complexity to the market?

MR. ERWIN: I think the question the Commission has to ask is, is it appropriate complexity. Is it complexity that's needed to get the rates just and reasonable?

CHAIRMAN WELLINGHOFF: Joe? Comment?

MR. BOWRING: Thank you.

So, old and new. The question becomes, when does new become old. New becomes old after the first auction. If you need to recover your capacity costs over 20 years, then that's why you pay old units the same as new units. The missing money is missing from everybody. It's going to be missing from everybody over the life of the asset.

That's why, while I understand it's tempting to try to distinguish there, it does not actually make sense as part of a market design, particularly going forward. If you build a new unit today, it's going to be old tomorrow. But if it knows that that's what the price signal is, it will require more money to clear in the capacity market the first time through.

I agree with you about just and reasonable. I'm an economist, so I don't know really what that means. But as an economist, I take it to mean, as I said before, the lowest -- I take it to mean competition which results in the lowest possible price. I agree with you: as long as that's what we both mean, that is the objective of markets.

On the MOPR question, I agree with you. We need to get the component prices right, and that's what we've said in our comments on unit-specific review; that everybody should be using common assumptions.

Finally, the point about the same capacity having the same impact. I'm not sure I exactly understood. I thought you were going to say something else. But it is right that any kind of capacity has the same kind of impact on the price. Therefore, it should clear through the market, get paid the same price, or not clear and not get paid. But there's no reason to treat them differently and to have different revenue recovery mechanisms. Let's treat it all through the market. That's the way it's supposed to work.

Thank you.

CHAIRMAN WELLINGHOFF: Thank you, Joe. Andy?

MR. OTT: I don't need to repeat. I think we're good.

(Laughter.)

CHAIRMAN WELLINGHOFF: You're good? Okay.

Anybody else on the panel have any -- yeah, Bill.

MR. MASSEY: Well, if I could respond to Mr. Erwin. The difference was, the state of Maryland set the wholesale price, required the EDCs to sign the contracts, and it was a 15-year revenue guarantee which other market participants did not have.

That is different in the capacity markets, and skews the capacity markets in a way that this Commission should, in our judgment, not allow to happen. And that's the purpose of the MOPR, which we encourage you over time to strengthen.

CHAIRMAN WELLINGHOFF: Robert, one chance for rebuttal.

MR. ERWIN: Let me try to clarify, anyway, this notion of Maryland is subsidizing power plants. That is not true.

The contract for differences irons out the capacity revenues that are going to come into the plant. Nobody knows today whether, in the end of 20 years, Maryland ratepayers will have paid CPD, or if CPD will have paid Maryland ratepayers. That will depend on what the clearing price of the capacity market is for those 20 years.

Our analysis came in and said, if the capacity price averages this, Maryland ratepayers will pay for five years and get paid for 15, and at the end of the day we'll be net gainers. So this notion that we're paying CPD every year for 20 years just isn't true.

CHAIRMAN WELLINGHOFF: And that was a net present value basis?

MR. ERWIN: Yes.

CHAIRMAN WELLINGHOFF: Shahid?

MR. MALIK: We at PSEG couldn't disagree with you more.

(Laughter.)

MR. ERWIN: Why am I not surprised?

(Laughter.)

MR. MALIK: You state that the intent is not to reduce price, which is great. But the very actions that you do do do reduce that price, and therefore do affect the market, and do affect new potential entrants into the market.

You know, I think that, as I mentioned before, I think there are clearly some legitimate reasons for states to get involved in promulgating their policies, whether it be renewables or whether it be trying to fix a local reliability issue. We don't have an issue with that. But it shouldn't be in a way that jeopardizes the construct of the market, whether it's the capacity market or the energy market.

CHAIRMAN WELLINGHOFF: I didn't mean to start a debate, but thank you. I appreciate it.

(Laughter.)

CHAIRMAN WELLINGHOFF: I'm done. Cheryl?

MR. DENNIS: Commissioner LaFleur?

COMMISSIONER LA FLEUR: Thank you so much, Mr. Chairman. I just had one follow-up question I was burning to ask during Commissioner Clark's time.

Mr. Erwin and Mr. Bentz, among others, both argued that state renewable contracts, or purchases made pursuant to state renewable rules, should be exempt from minimum-offer pricing requirements, because there's no intent to suppress the market. They're not being done intentionally to suppress the price. I'll grant that. They're being done to meet environmental standards for environmental reasons.

But my question is: don't they have the same effect nonetheless on reducing the price we're relying to send the investment signal? So, I mean, regardless of benign intent -- more than benign, very worthy intent -- don't they have the same effect on the market?

And for Mr. Bentz: isn't that particularly true with the uncurvy curve --

(Laughter.)

COMMISSIONER LA FLEUR: -- that the states have I think insisted on in New England? Would you be willing to think about a slope in order to accommodate your renewables?

(Laughter.)

MR. BENTZ: Thank you for that last question.

(Laughter.)

COMMISSIONER LA FLEUR: You're more than welcome, before the cone of silence descends on us.

MR. BENTZ: And I'm sure there's a lot of people in New England waiting for my answer.

(Laughter.)

MR. BENTZ: I guess I will answer, we have discussed it in the past. We had a lot of discussion a year and a half ago. I think there will be a lot more discussion, from what I heard from Bob's outline this morning with the demand curve coming.

I'm not in a position, Commissioner LaFleur, to answer that question. I understand why you're asking it.

To your first question, about the price suppression, especially on a vertical curve, the answer is yes. Obviously, if a couple hundred megawatts come in, you know, somebody has to leave. That's the tension that we started this panel with: how to work state public policy, you know, into the capacity markets.

I agree with Mr. Erwin's comments earlier, though. You know, the states will meet what is state law. These projects will be built. They will have to be built. So the question comes: as they're built, is there harm to the market as you get 2- or 3- or 4,000 megawatts of excess generation that's not counted in the capacity market? Is that cost-effective for consumers to have to double-pay for those?

I guess that's what I would ask the Commission to think of as well.

MR. ERWIN: Commissioner, the answer to your question is, yes. Another megawatt in the market has an effect on prices, and it will depress them.

But I would also point out to you that it's no different than a state which now says, we're going to have emissions limits on power plants. A power plant closes because they can't meet them, reduces the amount in the market, and that's going to help raise them.

Yes, they're going to have effect on prices. But it's going to work both ways -- or it could work both ways. Let me phrase it that way.

COMMISSIONER LA FLEUR: I'll resist the urge to continue this conversation. Thank you -- Chairman Massey?

(Laughter.)

MR. MASSEY: Well, I won't, but I'll be brief.

I think you're exactly right. The effect is precisely the same. I would just say it again. We're talking about a regional price signal that all resources count on -- demand response, efficiency, generation, all of the others. And any price suppression is going to have an impact on the willingness of those who are not subsidized to invest.

COMMISSIONER LA FLEUR: Thank you.

MR. DENNIS: Other Commissioners? Commissioner Clark, Commissioner Norris?

(No response.)

MR. DENNIS: Okay.

We just have a few minutes left. I don't know whether any more staff around the table want to ask anything -- oh, I'm sorry. Mr. Ott?

MR. OTT: I'm sorry. This is Andy Ott from PJM.

I'm not sure -- the answer you're getting on the renewables seems a little bit too simplistic. I don't think the effect is the same.

For example, 100 megawatts of investment in renewables shows up as about a 13-megawatt capacity requirement or capacity resource in PJM. And again, there's other areas where it might be 30 percent or whatever, depending on the quality of the wind resource.

So, the effectiveness of, if an entity were going to use a renewable portfolio standard, if you will, to manipulate price, it's not a very effective way to do it. In fact, the effect on the market is substantially different. It's not megawatt for megawatt.

One of the reasons the minimum-offer price rule is narrowly tailored in PJM is because of that. It's really, the resources that are most likely to be used to manipulate the market are gas-fired, et cetera.

Very similar, back to Commissioner Clark's question from some time ago -- for example, the state of West Virginia making decisions about its integrated resource plan. You never hear a word about that being used to somehow manipulate the PJM market, or there's any concern that that activity over there on the regulated side is somehow causing a problem. That's because they're looking at their composite requirement. The state's owning up to rate recovery for all resource recovery, 100 percent of the requirement in the state. They're not saying, I'm going to invest targeted in a small resource and let the rest of the state go on market.

So that's the kind of thing that I think you're seeing. It is a bit different. I apologize for jumping in.

COMMISSIONER LA FLEUR: Thank you.

MR. DENNIS: Sorry, I didn't see you.

We're close to 3:00 o'clock. Perhaps we could take our break and come back and start right at 3:15. Thank you.

(Recess.)

MR. DENNIS: Welcome back. We're ready to begin panel 4.

This panel is titled, Considerations for the Future. Let me introduce the panelists. We have Peter Cramton from the University of Maryland, Michael Hogan from the Regulatory Assistance Project, Susan Kelly from the American Public Power Association, Michael Schnitzer from Northbridge Group on behalf of the Electric Power Supply Association, Sue Tierney from the Analysis Group, and James Wilson from Wilson Energy Economics.

Commissioner Clark, when you're ready.

COMMISSIONER CLARK: Thank you, and thanks to everyone for being on this panel, and for everyone in the audience who's been hanging in throughout a very interesting but long day.

This panel, as Jeff noted, is to turn a little bit and focus on the future, some things that may be changing and ways that the stakeholders and the Commission may respond to that. One of the things that has been a trend throughout the course of this day is, the increasing focus on non-traditional types of resources, as opposed to what we had traditionally seen as really the backbone of the electric generation supply. We now have that in addition to other types of resources; so a turn, say, from coal, where we used to look at the coal pile, to gas, where it's instantaneous. Or, from a nuclear plant that's dependent on fuel rods to an intermittent resource that's dependent on the clouds and sun and wind and things like that.

So, my question would be: are there things that the Commission should be thinking about incorporating into the models that we have, the capacity constructs that we have, that account for this sort of change in where we're getting our fuel from; in term of whether we should just let some of these intermittency issues or, say, the gas issue play out in the market, or is there something we should be more proactively doing in terms of recognizing some of these changes? Or on a similar note, are there things that we could be doing to encourage, for example, intermittent resources as compared with some other sort of resource that firms it up and provides greater capacity certainty to the market, and how they interact with the capacity market?

So, I'll turn it over to the panel from there. Mr. Cramton?

MR. CRAMTON: Thank you.

That's a very good question. In fact, I think there are some things that the Commission should be thinking about. Fortunately, it actually brings us back to where we were some time ago, I believe, in emphasizing what's important in a well-designed capacity market.

I think a focus on the fundamentals -- Bob mentioned the three Ps: product, performance and pricing. I'd add a fourth p, planning, which I'm sure Bob would agree with. And the one that your question raises, the importance of the product definition, and what is capacity.

Capacity is not iron in the ground. Iron in the ground is worthless, worth absolutely nothing. What the consumer should be buying is energy in shortage situations. That's what's valuable.

So the capacity product needs to be defined in that way. And once you do, then it accommodates all resources. It accommodates storage. It accommodates intermittence, so wind, solar, the slow resource like nuclear, everything.

Essentially, what needs to be done in the planning process and the prequalification process is, you know, first, how much do you need. Then second, you need to rate each of the resources relative to this metric; that is, what is their capability to supply energy during reserve shortages.

That is their contribution to the reliability objective of the capacity markets. Once you do that, so now you've defined the products, then you just have to make sure that, in fact, you get what you're paying for. And you do that the same way we do with electricity in the spot markets. We have the day-ahead market, and then people have obligations that are made in the day-ahead market. And then deviations from that are settled according to the real-time spot market.

So, we do the exact same thing in the capacity market, where the capacity resources are taking on obligations. Those obligations are calculated based upon the expected performance during reserve shortage situations. And then the resources are paid additionally from the capacity payments more or less, based upon their realized performance.

So in fact, different resources should be paid different amounts. We should have one capacity price, but then the performance is going to be different ex post, and those that perform better are going to be rewarded in this second settlement. Those that are performing poorly are going to be dinged.

Then the ratings of the resources are going to be adjusted based upon actual performance. So in fact, what parties are paid is consistent with their long-run performance.

COMMISSIONER CLARK: Thank you.

Let's go to Sue Kelly first, and then Sue Tierney.

MS. KELLY: I don't want to be rude. Were you planning on going down the row, or were you planning on responding by card?

COMMISSIONER CLARK: It's a jump ball.

(Laughter.)

MS. KELLY: Then I will jump.

(Laughter.)

MS. KELLY: I just wanted -- it's a great question -- to look at the future, sometimes you have to go a little bit back to the past. And I just wanted to share my epiphany of the morning with all of you, which is: Mr. Ethier from ISO New England saying, if he had to do it over again, what would he like to see. What he said he wanted to see was more robust load-serving entities, with obligations to serve load. You need to have long-term contracts on each side, a more balanced view, only in capacity markets for adjustments on the margins.

Well, that's what we are in public power. That is our model. That has always been our model. And actually, there are RTOs to the west, that shall not be named, where all the LSCs have that model. So my point is, please don't make it so that we can't continue to do business, because frankly, we think we have it right, and it was wonderful to hear somebody else say that, too -- although I'm not sure he meant to.

(Laughter.)

MS. KELLY: Saying that, the reason I bring this point home is because, we are already out making the decisions that you're talking about. Mr. Jablonski, on the last panel, was talking about the city of Vineland, New Jersey. If you read his prepared statement, they are building new gas-fired, and they got an award from the Solar Electric Power Association for the amount of solar that they've put in on their system. So they are dealing with these issues now.

What I would like to insure that they have is the flexibility to do that, rather than being put into a Procrustean bed of a capacity market with a MOPR and a CONE based on one type of unit. And anything that you do that might be backed by a long-term contract -- heaven forbid -- is considered out of market and must be penalized.

I mean, we just have it bass ackward -- excuse the expression. Because in order to get the new resources that we're going to need -- I guess Commissioner LaFleur mentioned about how we've been in a capacity overhang up until now. I call it the biblical approach to generation planning. We've been in the seven fat biblical years, and now we're going to be going into the seven lean biblical years where we're going to have to make some hard choices. We're playing for keeps. We have to change out old resources. We have to pick new resources. We have to deal with the unhappy characteristics of some of those resources, and we need the maximum flexibility to do that, and we're going to need to make long-term investments.

So, when we do that, I would like to not be penalized for that. And that gets me to Mr. Tatum's discussion about a residual market. If this is a residual capacity market, then we can go out and do what we need to do to support the new resources to meet this new paradigm, and then clean up the excess in a residual capacity market.

So that's kind of my vision of where we need to go.

COMMISSIONER CLARK: Thank you.

MS. TIERNEY: I love following Sue Kelly.

(Laughter.)

MS. TIERNEY: I had a couple of epiphanies today, too. Hallelujah.

One of them is that, for as long as I have been in the electric industry -- and I'm amongst the oldest people in the room -- I have understood the resource adequacy one day in ten year scarcity requirement that we've all been talking about today. I have understood the operational requirements, making sure every single nanosecond that you're balancing the system properly.

But I think the system of the future actually has a different reliability construct that we need to start talking about. So, I bet you didn't expect this was what I was going to say.

The world of the future could come in a lot of different flavors and forms, probably will. But at least some of those have a situation where reliability isn't just about that one day in ten years. It's about different times of the day, just as it is in the short-term operating day, but that you can anticipate in a forward period that you're going to be having those kinds of circumstances, or at least want to make sure that you have products or definitions of reliability that get you to thinking about future requirements that are different than that one scarcity event.

I mean, the thing that I have understood in one part of my brain that we're talking about is, coming up with a residual payment for missing money for scarcity, but at the same time thinking that, in the famous DUC curve --

which, who knows, could happen in Massachusetts years from now, not just in California -- that one would have very different reliability requirements over the course.

Looking forward, and making sure that you plan for that type of outcome, that's number one. Number two, and maybe aligned with that, is that one could imagine actually a longer forward period for contracting -- sorry; a longer forward period for capacity markets, a short-term reconfiguration period, but that you actually have longer-term reconfiguration periods within the five- to seven-year period, so that you are accommodating changes in the markets.

I understand that one of the problems of looking much farther ahead is the planning challenges and the IRP troubles and all of that. I do understand that. But there could be some better ways to adjust the long-term or the short-term.

The third issue is a word that I haven't heard spoken here today, and that is that one can anticipate the next few years inviting the world of state implementation plans for existing power generators under the greenhouse gas rules that EPA will be issuing next year in proposed form, and will be coming out, it's anticipated, in the year after that. That would be 2015.

We've been talking about a forward market that takes us to 2016-2017. That's a period in which states will have to declare what it is they expect they're going to do with their resource mix, so that the generating units have a certain set of standards of emissions that they're going to meet.

We can assume every state's going to do that differently. It will come out a lot of different fashions. But we can't forget that here as we think about what the markets need to be adapting to, and I don't think -- that's an IRP in one form or another that each state's going to do, and we're going to have to think about that.

COMMISSIONER CLARK: Thank you. Mr. Wilson?

MR. WILSON: Thank you.

I think your question encompasses about a third of the issues we've spoken of today. You have the intermittent resources and integrating them. You have gas-fired generation that may have non-firm fuel supply at times, use-limited resources such as demand response.

Count me among what we could call, I guess, the purists who think that the resource adequacy construct ought to stay focused on peak day meeting one day in ten years, rather than trying to make it more complicated to include ramping requirements or tranches, that sort of thing. But within the one day in ten years, we meet that at least cost if we accommodate the broadest range of the different types of resources that can contribute to it.

I think a very good example there is PJM's integration of the limited demand response limited to ten days, six calls. They have an analytical approach to determine how much of that they can use, and still get full reliability value of it. And so, that meets a good chunk of their peak, 4.8 percent. So that's a very good way to meet that requirement, at least cost, by integrating limited amounts of that.

Otherwise, I would agree with so many other speakers who suggested that you really should focus on the energy and ancillary services market and getting the incentives right there for things like ramping ability and the DUC graph. There's one other comment I want to make about the famous DUC graph. It's a different situation from peak day requirements. If you don't meet your peak-day requirement, it curtails firm customers, and of course we don't really want to do that.

But if on a morning, an RTO doesn't appear to have enough ramping ability to accommodate all the variable resources that are coming at it, it's probably going to curtail some of those variable resources rather than, you know, risk not being able to meet the evening ramp. In that, you know, it kind of brings up the question of cost causation, because it is those variable resources that are creating that need for so much ramp.

COMMISSIONER CLARK: Thanks.

We've got two Sues and two Michaels. So we'll start with Michael Schnitzer.

MR. SCHNITZER: Yes, thank you, Commissioner, for the opportunity here.

I think I'm going to echo some of the comments that were just made by Jim. But I do think there is an issue of product definition that has been running through the conversation today, and I think there are two dimensions to that that are in relief here.

The first is, how much of a particular kind of resource can actually contribute to a reliability benefit on a peak day, and when do you hit diminishing returns? One of those was just spoken about, limited DR, and I think Dr. Cramton in his paper talks more generically about when wind and solar change the peak, then incrementally there's less effect, less benefit, et cetera. And so we need product definitions that take account of, both in a static and a dynamic sense, what the actual contribution of some of these resources is to peak.

The other comment about product definition, I think it was by Dr. Patton this morning. But he alluded to how capacity markets support the energy markets, which is: when you're a capacity resource, you have the obligation to offer or schedule every hour and every day your resource is available. And that's how the Andy Otts of the world know that they've got stuff to run the system every day.

So we have a challenge of the resources that only have six calls, you know, a year, or six calls or whatever. Are they the same as the classic resources, Commissioner, that you mentioned in the introduction to your question? You know, we know that nuclear and coal and gas -- we know what it means to offer or schedule every day you're available, and how that should count. What should it mean for resources that are more intermittent?

So we have to get over that hurdle. Every RTO has got a different methodology but similar approach to de-rating the capacity of some of these resources for getting the credit. I think there's a question: as those amounts grow, are the statistics that underlie their analyses sufficiently robust to not over- or under-compensate those resources? We'll need to look at those over time as the proportions and the mix shifts, as your question suggests.

The other comment I wanted to end with was that, you know, the number one priority for fixing the capacity markets may well be fixing the energy markets. You know, these scarcity prices, energy and ancillary services, are just critical. The combination of lower natural gas prices and the influx of resources associated with state policy goals do have an effect of reducing energy prices and energy margins, and those put more pressure on the missing money that we have talked about that you've heard about all day for the capacity markets.

And so, part of that is obviously unavoidable, and not a bad thing for consumers, by the way, for natural gas prices to be lower and the like. But to the extent that we're artificially suppressing those energy prices in scarcity periods, and not even just in scarcity periods -- in periods where an oil unit is committed after the day-ahead market because the ISO thinks there may be an issue the next day; it sits at its minimum -- it won't set LMP. Yet a judgment was made at 6:00 the evening before that there was a cost that should be incurred to make sure that we're reliable at 4:00 tomorrow afternoon, but at 4:00 tomorrow afternoon we don't show anybody the price signal of the fact that decision was made at 6:00 the evening before.

So, we have a number of examples where the energy markets ought to be improved. Those will give greater incentives for storage, for quick start, for all of that, if you stop understating the differential between off-peak and on-peak prices. You will help yourself in a lot of ways, so I think it's important that the Commission start there, if you will, in terms of capacity market priority lists, would be the energy markets.

COMMISSIONER CLARK: Thank you. Mr. Hogan?

MR. HOGAN: Thanks to the Commission for having us today. It's been a long but very interesting day.

I'm working on a new script for a movie called "The Missing Money Problem."

(Laughter.)

MR. HOGAN: It'll probably come as close to describing the missing money problem as many of the comments about it have come today.

Commissioner, you asked about the implications of future changes, and I think our view is, arguably the most, and certainly one of the most, important ways that tomorrow is going to look different from today from a reliability perspective is the inevitable growth of the share of supply that comes from variable resources or intermittent resources, to use your term. It's become very commonplace to observe that these resources are variable and intermittent, and that they impose challenges on the system. But the implications for the change in the amount of flexibility and the balance of resources on the system that they have is probably less well understood or less well appreciated.

If you look at -- Sue Tierney actually stole one of my lines from my paper, which is that in the future, how many resources are necessary for resource adequacy becomes a contingent metric. How much will depend on what time.

MS. TIERNEY: Sorry.

(Laughter.)

MR. HOGAN: No, that's okay. Imitation is the highest form of flattery.

I think that's absolutely true. We think that's absolutely true. And there have been a number of comments to the effect that, well, we should let the energy and services markets deal with operational issues like flexibility, and we should let the capacity markets deal with resource adequacy.

That formulation presumes a level of design purity and a level of convergence between theory and practice that we simply don't have today. As was discussed in the first panel this morning, if energy and services markets were working the way the theory says they should, or being implemented the way the theory says they should, they are perfectly capable of delivering an economic level of resource adequacy. And in that world, the role of a capacity market is to deliver the political margins of resources needed over and above an economic level of resource adequacy.

Put differently, an energy and services market working properly would deliver 8 to 10 percent, whatever the right number is, reserve margins. But for political reasons, historical reasons, whatever, we set the targets at 12 percent, 14 percent, 15 percent, 20 percent.

I'm not here to debate whether that's the right number or the wrong number. The point being that, in a world where the energy and services market was working and could deliver and could drive a shift in the mix of resources in the portfolio to the level of flexibility that the system is going to need, then we could have the kind of capacity market that Mr. Tatum talked about or that Sue talked about, which is a residual market. And that, frankly, would be one that looks like the one they have in Sweden or that's been proposed in Germany, which is a strategic reserve with a strike price that's somewhere at or above a real value of lost load, say $15-, $20,000 a megawatt hour.

That's not what we have. The capacity markets that we have in the eastern RTOs is a hybrid. It's not only delivering that political reserve margin, it's also -- whether we say it explicitly or not -- it's also serving to address shortcomings in the way the energy and services markets are functioning relative to the theory. And if energy and services markets are struggling to deliver economic reliability, as the design implies that people believe they are, then they will certainly struggle to drive a shift in the mix of resources towards the more flexible mix of resources that a properly functioning energy and services market would presumably deliver.

That's true even if there weren't going to be big changes in the demand for flexibility on the system. But as almost every analysis out there shows, we can expect as the share of variable resources on the system grows, a significant growth in the demand for flexible resources on the system relative to the levels that have historically been required.

We need, if we talk about comparability of products, comparability of services, we need to make sure that resources that are capable of meeting specific needs that the system has are being paid the same level as other resources that have the same capabilities. Resources that don't have those capabilities should be being paid the same amount as other resources that don't have those capabilities.

That's it. I'll leave it to the rest of the panel to have a chance to get in and ask their own questions.

COMMISSIONER CLARK: Thanks.

Sue, did you have one last thing you wanted to circle back?

MS. KELLY: I just wanted to note that there's more than one way to address the variability problem that's caused by integration of variable resources. My members in

California, for example, have their own DUC curve, which they have filed in their own docket, in the California docket, which indicates that they have constructed their portfolio to both meet the resource needs and the renewable requirements, but to do so in a way that actually follows their own load.

So I would caution. Building the entire market around the assumption that variable resources are going to be loaded first, and that everybody needs to pay for that variability, is not necessarily the right way to go in all cases, because there are some people out there who are trying to bury their own dead and deal with variability on their own, and they should not be penalized for having done that.

COMMISSIONER CLARK: Thanks. Sue?

MS. TIERNEY: Thank you, Commissioner.

The one addition I wanted to make is that my reference to the state implementation plans for addressing greenhouse gas emissions from existing fleets was not intended to indicate, on the one hand, that I don't support competition. Certainly I do.

But one could imagine that in that type of proceeding, one thing that a state could conceivably do is actually limit and restrict the amount of resources coming out of fossil units -- a coal plant, a natural gas plant --

to a particular period of a day. Were that to be the case, we actually have a different set of energy-limited resources than we would in a situation where that didn't exist. So I think it's a different world ahead.

COMMISSIONER CLARK: Thanks.

I want to turn it over to Chairman Wellinghoff. I know he has to leave here in a few minutes.

CHAIRMAN WELLINGHOFF: Thank you. I appreciate it. I won't take too much time here.

Professor Cramton, Peter, I have a confession to make. I ate too much for lunch, and when I did that, I was sort of somewhat, you know, in an after-lunch daze here. And then I heard you say, "Iron in the ground is worthless," and I woke right up.

(Laughter.)

CHAIRMAN WELLINGHOFF: Because I know if I had said that, I could already see the Wall Street Journal editorial.

(Laughter.)

CHAIRMAN WELLINGHOFF: So I'm glad that you said it first. But I want to talk about that a little bit.

I want to talk about the capability to supply energy during reserve shortages, which you're defining with the capacity market is trying to solve. I'll admit, that's a historical operational problem, right. But don't we have other historical operational problems -- not historical, excuse me.

Don't we have operational problems that are not historical, but are ones that are emerging, that are very quickly emerging; one being this ramping issue, the other one being oversupply from wind in early morning. Don't we have to figure out how to meet those problems as well?

MR. CRAMTON: Yes, we do. But I think that if we have the capacity market focused on making sure that there's enough -- that capacity resources are rewarded for their ability to supply energy during reserve shortages, then you're going to have a coherent capacity market that's sending the right price signal.

Now, there could well be -- and certainly, the other thing that you have to do with respect to the intermittent resources, is you have to improve your energy ancillary service markets to accommodate those resources. And I think actually, a well-designed capacity market focused on the products that I mentioned is going to be consistent, is going to be complimentary, with improvements in the energy market.

So, for example, we need the shortage pricing. That's been the big problem. That's the source of the missing money. Well, with the product as I've described, then with a strong performance incentive, then what's going to happen is, the load is going to be hedged against these high scarcity prices by the products they purchase in the capacity market. Therefore politically, it's going to be acceptable to have high scarcity prices, because essentially then it's just between the suppliers. Those that oversupply, that supply more, are going to be rewarded. Those who supply less than their obligation are going to be punished.

And very little quantity -- the suppliers are going to be in a largely balanced position, so very little quantity is going to be traded at those very high prices. But you need those very high prices in order to motivate those marginal responses.

So I still think that one has to work on both the capacity market and the energy market and the ancillary service markets, but that a well-designed capacity market, focused with strong product definition and strong performance incentives, is going to lead to these improvements in the energy market.

CHAIRMAN WELLINGHOFF: But you agree that there may be products necessary, and therefore a market necessary to obtain those products, for meeting these needs of ramping and oversupply.

MR. CRAMTON: They largely should come forward based upon the anticipation of the rewards that they're going to receive in the capacity market and in the energy and ancillary service market.

CHAIRMAN WELLINGHOFF: But aren't you saying that we aren't going to pay them anything in the capacity market; that we should only pay for things that provide for the capability of supplying energy during reserve shortages?

MR. CRAMTON: If I can ramp quite quickly, then I will be there when the price is $5,000 or whatever it might be in the energy market. So those resources, and an inflexible resource like nuclear, is going to get paid for that, because it's going to be providing that energy.

CHAIRMAN WELLINGHOFF: That can't ramp at all.

MR. CRAMTON: Even if they can't ramp at all, they're going to be on already. So they're going to be providing the energy that's needed in the reserve shortage situation. So that's their contribution.

CHAIRMAN WELLINGHOFF: How do we insure we get that incremental additional ramping capability that we need? Are you saying that you believe that those resources will be adequately compensated by an energy market if we design it properly?

MR. CRAMTON: Yes. We'll be compensated by the energy market and the capacity market in combination. All those sources of revenue -- take a stock resource. It's going to be looking at, it will receive a capacity payment for its expected service in the shortage hours. And then it's going to be, depending upon the form of the shortages, it will be able to contribute more or less. And that could be quite substantial payments for the storage resource.

CHAIRMAN WELLINGHOFF: That's what I wanted to make sure I understood. You do agree that things like storage and demand response and other non-traditional resources should get paid for capacity.

MR. CRAMTON: That's right, yes. They should be paid for capacity to the extent that they provide the service.

CHAIRMAN WELLINGHOFF: All right, thank you. I appreciate that.

Mr. Wilson, I had a question that actually related to a comment you made on this ramping thing, I guess on the DUC ramp. You were indicating that there may be some curtailment of the variable resources. I didn't quite understand what you were saying there. Could you explain that, please?

MR. WILSON: I think, if in the morning the ISO is looking at a really fat DUC, so he's looking at a need for a huge amount of ramping in the evening, when the solar and wind drops off --

CHAIRMAN WELLINGHOFF: He's going to have to ramp down in the morning and then up in the evening, right?

MR. WILSON: Yes.

CHAIRMAN WELLINGHOFF: Do both. You've got to ramp down very quick and then you've got to ramp up very quick.

MR. WILSON: Right. But if he sees that he just doesn't have the amount of ramping to ramp up in the evening, then what he's probably going to do is, he's going to curtail, not accept, some of those variable resources and dispatch something old-fashioned, like gas-fired resources or coal -- not in California, perhaps -- that will run in the trough, but also be there for the ramp. He simply will not be able to accept that quantity of variable resource.

CHAIRMAN WELLINGHOFF: But he'll have no variable resource to curtail, because this will be at a peak time in the summer when there's no wind. What he'll have is all the solar PV all of a sudden goes off when the sun goes down.

So he's got no variable resources to curtail. The solar in fact goes off. That's his problem, and he's got to ramp immediately with something.

MR. WILSON: Right.

CHAIRMAN WELLINGHOFF: So I'm not sure how in that situation you curtail any variable resources. Typically in California at the peak time, there's no wind.

MR. WILSON: Okay, let me clarify.

In the morning, he'll have to say to some of the wind, I'm going to have to dispatch some gas-fired resources in order to be able to meet the evening peak, which means I just can't accommodate, right from the morning, all of the wind and solar that I'm being offered. He'll have to run something else that will run starting from the morning and will allow him to meet the evening peak that he would otherwise not run.

CHAIRMAN WELLINGHOFF: I'm not sure I still understand that, but thank you, though.

Let's see.

(Pause.)

There's a possible problem of not knowing where I'm going -- Sue Kelly, let me --

(Laughter.)

CHAIRMAN WELLINGHOFF: I continue to not understand this, and I don't know why, about the issue of voluntary capacity markets. So explain to me what you want us to do with respect to voluntary capacity markets.

MS. KELLY: Okay, I will.

CHAIRMAN WELLINGHOFF: You're saying, you can't voluntarily just self-procure yourself now. We force you to be in an RTO.

MS. KELLY: Correct.

CHAIRMAN WELLINGHOFF: What areas of the country do we force you to be in an RTO?

MS. KELLY: In New England.

CHAIRMAN WELLINGHOFF: You must be in an RTO? You have no choice?

MS. KELLY: Believe me, my members in New England, if they wanted to pick up and move Braintree out into the ocean, you can't do that. You're physically located where you are. If everything around you --

CHAIRMAN WELLINGHOFF: Physically located, but you don't have to be a member of the organization, right?

MS. KELLY: Well, if you have to take transmission from the organization, it kind of is silly not to be a member. Because then you have no say in the stakeholder process.

CHAIRMAN WELLINGHOFF: It's not a legal requirement. Let's make it clear here. It's not a legal requirement.

MS. KELLY: Well, we can have the discussion of whether it is voluntary to participate in an RTO. The position of our association is, if the transmission owners around us are in it, it's extremely difficult as a practical matter to live not being in it.

So, my argument would be, if we are pretty much required to be a member of the RTO, or we cannot pay our membership fee, we cannot go to the stakeholder meetings and will be forced to do everything anyway. So that doesn't make a lot of sense.

CHAIRMAN WELLINGHOFF: SMUD's not a member of an RTO.

MS. KELLY: They are outside the California ISO's footprint.

CHAIRMAN WELLINGHOFF: They could be surrounded by the footprint, though. LADWP is surrounded by the footprint, right? LADWP is completely surrounded by the footprint.

MS. KELLY: I don't think they are.

CHAIRMAN WELLINGHOFF: I think they are. I guarantee they are.

MS. KELLY: Are they contiguous with IID?

CHAIRMAN WELLINGHOFF: No, they're not contiguous with IID. Edison's completely surrounded, I'm sure, and they're not a member of the RTO.

So again, I'm trying to understand this voluntary --

MS. KELLY: I believe this conference is limited to the three eastern RTOs.

(Laughter.)

MS. KELLY: I read a footnote to that effect.

CHAIRMAN WELLINGHOFF: You did, you did.

MS. KELLY: And I will tell you that most of our members of these three eastern RTOs are what are known as transmission-dependent utilities. When that's the case, they don't have their own transmission, such as the ones you mentioned in the west do. It pretty much becomes a requirement for them to be -- if they are in that footprint, and they need to be able to receive the power they need to serve their retail customers --

CHAIRMAN WELLINGHOFF: It's not open access on those transmission lines, and they can in fact get firm service on those lines for their capacity?

MS. KELLY: The embedded IOUs whose system they are in are in the RTO, have turned over their transmission facilities to the RTO. And if you want transmission over them, you need to be a customer of that RTO.

So, I mean, as a practical matter, that's where we are. Now --

CHAIRMAN WELLINGHOFF: The customer requires that you be in the capacity market of that RTO?

MS. KELLY: Yes. We are required to be in the market. Jim Wilson, do you have a different view of that?

(No response.)

CHAIRMAN WELLINGHOFF: I don't think he wants to get into this.

(Laughter.)

MR. WILSON: Please don't drag me into this.

(Laughter.)

MS. KELLY: Andy Ott? Are my members required to be?

MR. OTT: Andy Ott. You actually are not required to be a member. You would have to take transmission service. You'd have to buy transmission service. But you could form your own control area. You could essentially contract bilaterally with generators. You could buy firm transmission service and sit it out.

The point is, I think what you're going to say, and I would agree with you, economically, that's a lot more expensive than being in the RTO. But you really don't have to be a member of the RTO. You could go out on your own.

MS. KELLY: Forming our own control area, I believe, would not be desirable from you, the Commission's perspective, especially from a NERC reliability perspective. Having a lot of really teeny, tiny control areas is not something that you really want to have; a lot of different BAs nested within the RTO.

CHAIRMAN WELLINGHOFF: Like we do in the western United States? You're right.

MS. KELLY: Well, they're not nested. They're all contiguous there.

So I'm not going to concede that it's voluntary.

(Laughter.)

MS. KELLY: I take Andy's point. I take your point. But I think as a practical matter, if everybody around us is in, we -- you know, no system can be an island.

CHAIRMAN WELLINGHOFF: Call it a draw. Thank you, Sue.

MS. KELLY: Is that it? I thought that was just the lead-in for the real whack to the side of the head.

(Laughter.)

CHAIRMAN WELLINGHOFF: James? Thank you.

MR. WILSON: I just want to add real quickly, with regard to voluntary markets: on the one hand, you have your short-term energy and ancillary services market. At the other extreme, there's the long-term market for new capacity or for major investments in existing capacity that takes into account all attributes between those six-year capacity markets.

If it looks very small and very residual, there wouldn't be much concern about market power on buyer or seller's side, and it could be voluntary.

CHAIRMAN WELLINGHOFF: Thank you, James.

That's all I have. Thank you.

COMMISSIONER NORRIS: Well, I was going to start with you, Sue, but I'll give you a break.

(Laughter.)

COMMISSIONER NORRIS: I'll come back to you.

Let me go two different directions here, and then give Cheryl a chance. Let me go back to the flexible resources issue.

We are talking in this panel about the future, and I don't see any way in which the future, what we're looking at, we're going to need a different mix of resources than we've had to have in the past, largely to respond to intermittent resources in a different kind of resource in the future. Which means this is about adequate resources, right?

So, there seems to be two sets of opinions, if I can generalize: those that think, within the capacity markets, we can set up some kind of tranches; more thoughts about how that works, do we need to have different capacity markets for different types of resources we need an adequate amount of. Or, there's some folks who are saying, no, this is still resolved in the energy markets, energy and ancillary services.

Is that strictly through shortage prices, or is that how it's resolved on the energy side to get the right amount of the kind of resources we need? Help me sort through, whichever side you're on, how that works.

MR. CRAMTON: To me, the idea of tranches is a nightmare. The reason it's a nightmare is, you're going to have to make all kinds of additional decisions that are going to have huge effects on what people are paid and what you get. But what people are paid, that's the biggest concern, because that's going to lead to all kinds of rent-seeking in the process of setting out.

Just think of it. The size of the tranche is going to have a huge impact on the price that that tranche is paid. So you can basically push one tranche's capacity price to zero and have a very high price for somebody else. There's some difficulty in establishing a single demand curve. Now, you'd have to establish demand curves for each tranche.

I think that it is not workable with respect to the capacity markets. That's not to say you can't have other instruments, such as a market that's just procuring a sufficient quantity of renewable resource, and that that's taken into account in the planning of the capacity markets. And the contribution of that resource is understood and accounted for.

But I think the tranches is a very dangerous idea. It would lead to, not just massive complexity, but the worst kind of complexity, which would invite extensive rent seeking.

COMMISSIONER NORRIS: Michael?

MR. HOGAN: Great question.

I mean, I think the theory is that if scarcity pricing in the energy and services market is reliable enough, accurate enough, and is allowed to emerge, as it will, without offer caps, that as the need for flexibility grows, more flexible resources will be able to earn more in the market, and therefore will prosper. And less flexible resources will suffer as a result, because they can't respond as quickly to fast-changing wholesale prices for energy and services.

That's the theory. The same theory says we don't actually need a capacity market to deliver economic reliability. Those same dynamics in the energy and services markets would deliver a 10 percent reserve margin, and that's reflective of the value of lost load, somewhere around $15,000 to $20,000 a megawatt hour, which is what most economists I think would say is probably about an average value of lost load, and Bob's your uncle.

Two problems with that. One is that most people seem to believe, and I think they're probably right, at least now, that the theory of how the energy and services markets should value more flexible resources is not yet currently playing out according to plan in the real-world markets.

For the same reason, we don't have what the theory says should be the capacity market, which is a strategic reserve that sits off and is almost never called on, and is really designed to provide that extra margin of reliability that customers wouldn't actually pay for, broadly speaking. You know, people run around, Obamacare, Obamacare. I mean, we've had Obamacare in electricity reliability for years. We've required people to pay for insurance.

MS. TIERNEY: Don't say that.

(Laughter.)

MR. HOGAN: It's true. We require people to pay for insurance they wouldn't otherwise purchase themselves, for a service they don't actually receive. Don't get me wrong; I love Obamacare.

(Laughter.)

MR. HOGAN: If the theory was working, that's the kind -- you know, we'd have our strategic reserve, the same way the Swedes do. The BDEW in Germany has proposed exactly the same thing, a strategic reserve. The strike price, $15-, $20,000 a megawatt hour. And we'd be done.

That's not what we have. What we have is a capacity market that is kind of a hybrid. It addresses both things. Whether we say it or not, it actually deals with the fact that people see imperfections in the way the energy and services market is actually delivering price signals.

So we believe that, if we need a capacity market to deal with the fact that the energy and services markets do an imperfect job of foreseeing the need for new capacity, then certainly we need a capacity market that also deals with the fact that they do an imperfect job of foreseeing the need for more flexible resources. To criticize it because it's complex -- I mean, that's kind of like major league baseball sort of criticizing the NHL because the hockey season's too long. I mean, that horse has well and truly left the barn. These are complex animals, and we shouldn't be afraid of a little bit of additional complexity if that's what's required to get it right.

COMMISSIONER NORRIS: Sue?

MR. HOGAN: I'm sorry. By the way, we already have tranches. To PJM's credit, they've tranched the DR auction. And as far as I know, it's working just fine.

COMMISSIONER NORRIS: Sue?

MS. KELLY: First of all, let me say, this is an issue on which there is some diversity of opinion within my membership. And as a trade association, I love all my members. So my remark is going to be highly balanced.

(Laughter.)

MS. KELLY: There are some regions where the markets are already quite complex, and people feel like the best way to call forth a new product is to support it through the possibility of examining -- tranches, I think we're pronouncing them. I've had a lot of philosophical discussion about the best way to pronounce that word.

So, there is some interest in it in some regions. On the other hand in PJM, it was noted I believe in your paper that, when the original market came in, there was discussion of four different tranches. And so I went back to the brain trust in PJM and said, you know, would you be considering that now? And the answer to that was, no. So just note that.

I think I personally am quite concerned about the additional opportunities for arbitraging between. It's one thing that we have learned, to our sorrow, since these markets came in, in that there's always an extremely enterprising financial player who is out there, who's able to arbitrage between those markets, and will do that if that will bring them in additional revenues, which generally have to be paid by consumers.

But that doesn't mean that I don't agree that we need to have different types of capacity and different types of products. I guess my argument would be that again, if we had a residual market with the ultimate tranche of an individual, bilateral contract best suited to procure the type of resource needed to back that particular resource -- in other words, it's the ultimate in customization -- is let everybody go out and make their own deal, as long as it adds up to what the RTO needs it to add up to to maintain reliability and to integrate the resources that are chosen.

So, I would kind of argue for a more bottom-up approach to that, rather than attempting to impose by administrative fiat a series of markets. But again, I have some members in some regions who are interested.

COMMISSIONER NORRIS: Michael?

MR. SCHNITZER: Let it not be said that you are not on-message today.

(Laughter.)

MR. SCHNITZER: What I thought I heard from the RTO panel for the three RTOs we're talking about here, were two things. One, that none of them saw a current need to tranche the capacity market for operational needs. And secondly, that there could be improvements to the energy and ancillary services markets that were important. I think that was pretty universal across the three RTOs. If somebody else heard differently, then I'll stand corrected.

So for what we're talking about today, I think what we're hearing is we should start with the energy and ancillary services. You know, Michael, I guess I don't accept the premise that, because they're not currently doing the job, then can never, and so therefore we should just assume we need to do it in the capacity market, because the present energy and ancillary services markets may not do the trick.

I think that it would be better to focus on the existing energy and ancillary services markets to see what we can do. And I say this for a couple of reasons. The first is that when the rubber would hit the road and we might be more concerned, or I might be more concerned than I now am, is that what the market operator is trying to figure out is: how does my minimum load plus exports compare to the minimum load of all the resources I want to have committed to serve the peak for the next day? And can I squeeze enough resources into the commitment at at least their minimum load so I have enough capability to kind of move up and down through the course of the day?

I think in these markets, I'm not hearing that there's a problem with that currently; that they can get that commitment in place, which gives them enough flexibility to deal with the intermittency that we have. Now, if you price that right in the energy and ancillary service markets, the differential between on-peak and off-peak, and the compensation for somebody who can move very quickly, will give some incentives for people. But, as long as you have that capability to get that commitment that will work for you, you're okay.

The problem with trying to do it in the capacity market, which I think is what Peter was alluding to, is: how do we know, and who decides, whether the economic way to have that ramp capability is a steam unit with a turndown ratio or an operating range of 4-to-1 between its P-MIN and its P-MAX, but some heat rate penalty when you put it on at P-MIN, versus a brand-new LM whatever that'll start in ten minutes that via the ISO New England market monitor trigger price, is going to cost, you know, $13 a kilowatt month, whatever that one works out to.

So who makes that decision, and how do you structure the capacity auction so that you retain the right capacity in that respect? I think we're much better off handling that in the energy and ancillary services markets, and letting the stock adjust over time -- which I think it will -- as opposed to declaring that we need to go solve this -- right now, we need to go solve this other, much harder problem.

COMMISSIONER NORRIS: Sue?

MS. TIERNEY: This is a really hard question. Clearly, we need to improve the pricing in the energy and ancillary service markets. One of the very things that Michael said a minute ago was that, we need to make sure that if a grid operator is committing a resource in advance of need out of merit order, that it is not distorting the energy price if indeed it is there for reliability purposes. Because otherwise, that's a problem in the energy markets, because we're mixing the two of those.

That is an example of one that leads me into the, let's fix the energy and the ancillary service products in the real term markets urgently. Because this is a real issue in current times. And let's -- okay, I'll stipulate. Let's just call the capacity markets a one-day-in-ten reliability standard, and the missing money for that purpose. But we need other things.

We need other things because, during this period, as I said -- and I won't try to repeat every word in my gazillion-word paper -- every bit of the world tells us that we can expect low gas prices. By the RPS requirements, we're going to be doubling the amount of renewables in this region by 2016, and then another three times the amount by 2020. That's happening at the same time the fossil units are going to have to be emitting less.

We are going to have a set of constrained resources. The grid operators, who understandably want to keep the lights on, like we all do, they're going to curtail resources if they don't have -- they're going to curtail sun in the afternoon if they don't have ramping capability. If prices in the short-term markets fly up, I don't trust the politicians -- and you're not politicians, so we can trust you guys. But I've seen lots of examples of worries when prices fly up in those real-time markets.

We need other products to address this ramping capability. So don't call them capacity products. Don't call them short-term day-ahead real time prices. But there's got to be something else.

MR. WILSON: The missing money relates, I guess one way to describe it is two things: the various shortcomings in the energy and ancillary services markets, and also the fact that we're shooting for a very conservative resource adequacy criterion, one day in ten years. Professor William Hogan and others will give us a long list of all those shortcomings in the energy and ancillary services markets, and as we work that list down and cross a few out, Professor William Hogan and others will take a further look, and add a few more to the list. They're not making them up, they really are. So that's a really hard problem that we're not going to solve soon enough with what the capacity market is providing.

But given that that missing money is provided through the capacity market incrementally, we need to provide an incentive for, say, fast ramping ability. And I believe that that is a much simpler problem to solve. And if an RTO is very clear about what the products are that he anticipates he will need in the future to integrate variable resources, makes it real clear that he's going to compensate for them in order to get them through the energy and ancillary services markets, I think that will be a sufficient incentive to bring it forth.

If you do it in a forward market, you're probably going to forecast incorrectly what you need. You're going to satisfy it in a forward market with the resources available at the time, which kind of preempts some of the newer resources that might come along. So I think it really is doable and much better to do it through energy and ancillary products.

I also want to second the statement that it would be a nightmare. What PJM does with DR products, which is sort of like tranches, is much simpler than trying to do various operational products, yet it is very complicated. That was a very complex addition to PJM's markets. I like it because it accommodates some resources that contribute to reliability, but it's a lot of complexity.

COMMISSIONER CLARK: I mostly agree with you, Sue. This is very, very complex.

(Laughter.)

COMMISSIONER NORRIS: I think it's pretty obvious we're going to need these different flexible resources. I mean, someone said earlier, Massachusetts is going to face the California DUC curve at some point.

But I'm troubled by the fact that we have capacity markets because we accept that we can't solve the problems we want to solve through an energy market. Yet some of you are saying, well, go ahead and solve this problem in the energy market, when we know there is political resistance to scarcity and shortage pricing.

So if anyone wants to take a crack at this, which is, neither of these -- one is perhaps complex, one is perhaps politically unpalatable. Which is the more likely one, in the end, that we'd be successful in accomplishing?

Go ahead, Sue.

MS. KELLY: I just want to make one point, then ask a clarifying question. Because I think we may be setting up a slightly false paradigm here, because we've been talking only about the energy markets and the capacity market. But of course there's an array of ancillary services markets, and it seems to me that one way to start to address this problem -- and I believe you even note this in your paper -- the solution is to develop additional services products with the characteristics we desire, which I think is kind of an alternative way to deal with that that may get some of the products that we need and avoid the horrible nightmare that my friends on each end seem to fear.

COMMISSIONER NORRIS: I probably misspoke.

MS. KELLY: Okay. That's why I was asking

COMMISSIONER NORRIS: The energy market we're talking about is probably where you're going to find that added value of what the service can provide.

MS. KELLY: Having said that, the only thing I will add to the discussion -- because there's some great minds on this panel -- is that every time I hear about how we need, quote, to get the prices and the services in the energy and ancillary services markets, quote, right, all I can think of -- I think it was Paul Newman being told that he needs to get his mind right back in prison. I think it's "Hud". I can't remember which movie it is.

But that really starts to worry me. Given that my members are controlled by local elected officials, some of those extremely high prices could be a concern. So it just makes me all the more interested in being able to have a physical hedge against those prices so that, you know, if we can under our business model, contract forward to avoid some of that, that we'd have the opportunity to do so.

COMMISSIONER NORRIS: I'm going to come back to you on that. Michael?

MR. HOGAN: Exactly. If we got shortage pricing right, people would be hedging with long term contracts.

MS. KELLY: That's what I want to do.

MR. HOGAN: No, exactly, and that's what the market should be driving you to do. As Sue Tierney said, absolutely we should work on it. And to PJM's credit -- you know, PJM's recently done the operating reserve demand curve and incorporating emergency demand response in the formation of cash-out prices in the balancing market, all these things that will help sharpen and make more reliable and accurate shortage pricing. Getting all that right has all these wonderful beneficial consequences.

But again, if you do all that, frankly, the argument for a capacity market gets pretty thin, because it starts to address most of the issues that capacity markets today are trying to address, which is shortcomings in shortage pricing in the energy and services market. In that world, where you, quote, get shortage pricing right, whatever that means for you or Paul Newman, in that world, that sort of sun lit up, and you've got a well-functioning energy and services market and a strategic reserve. You don't really need these sort of complicated single clearing price auction capacity markets. They become somewhat redundant.

We're just not there yet. And as I think I said in my submission, for as long as there's a robust argument for continuing with the capacity market model that we have in the eastern RTOs, there is an equally robust argument that says, something needs to be done to make sure that we're properly valuing the need for additional resource flexibility. Because the energy and services markets just won't get it done, in the same way that they apparently aren't getting it done in the capacity markets

COMMISSIONER NORRIS: Bob, I'll come to you, then come back to the panel.

MR. ETHIER: Thanks for the opportunity to interject here.

I just wanted to note that New England actually had some experience with procuring flexible resources in advance. We have a forward reserve market, which looks quite similar. And I guess the observation I would make is that, you really need, for that to work well, you need a robust spot market for that same service. If you don't have that, then you have no way to cash out the folks who actually don't deliver what they said they were going to deliver, and that's going to happen, right. Not everybody can deliver what they promise forward.

So I think it's sort of a false choice that we're talking about here. Oh, do we do it forward or do we do it spot? We have to do it spot, to me. And then the question is, does it make sense to also do it forward? That's a fair discussion to have. But to try to do it forward without doing it spot, I think, is going to create problems. And frankly, our problems with the forward reserve market mainly revolve around the fact that it's not well-integrated with the spot market and doesn't interact in as clean a way as you would like it to, and in a way that forward markets traditionally interact with spot products.

MR. HOGAN: I neglected to thank Sue for pointing out that in our paper, we do talk about that as an alternative, forward services procurement. If someone doesn't want to deal with complexity of apportioning the forward capacity market, that is certainly an option. But something needs to be done.

COMMISSIONER NORRIS: Peter?

MR. CRAMTON: I agree with Bob that it certainly has to be done. THe fixes have to occur in both the spot market and in the forward market. In fact, the spot market is the foundation, and the most critical.

I think that where your specific question takes me is that, in order to get the spot market right or righter -- we're not going to get it perfect -- we know that the prices are too low during scarcity periods. I think there should be consensus on that. There's lots of empirical evidence.

What a capacity market with strong performance incentives does is, it puts the obligation to supply during reserve shortages on the participants, on those that are selling capacity, and those that are able to deliver more are getting paid for it at these high scarcity prices. So the very strong motivations from the spot market are there, but what it does is, it makes the spot market work better, because you have people taking on the capacity positions far forward, so that they have balanced positions in the spot market.

They don't have an incentive to create scarcity events. Instead, they're well-motivated just to be there, but largely in a balanced position, which takes the heat off the politics. High prices are problematic when you have a lot of volume trading at those high prices for extended periods of time, and that's the motivation for strong performance incentives.

So the load is perfectly hedged by the obligations that the suppliers are taking on. The suppliers are hedged because of the physical reports, and all the wonderful work they're doing maintaining their plants and having dual-fuel capability, and all these things so that they know that they can be there. So they've got what they need to hedge physically against this financial obligation, and that overall reduces risk to the system and is, I believe, workable.

COMMISSIONER NORRIS: Two more on this, and then one more question.

MR. SCHNITZER: I'm not sure I can help with the politics. But I just would point out that, at least from my perspective, the energy and ancillary services fixes that we're talking about here basically affect real-time pricing, in the most part. So we're not talking about -- I don't know what PJM and whatever, it's 90-some-odd percent of the energy clears day ahead and all the rest.

The real-time prices obviously are important to the price formation day ahead, but we're not talking about, you know, sort of these dramatic price swings, you know, occurring in the day-ahead market. So I would hope that putting these important fixes in place in the real time ancillary services and energy markets would be politically palatable and would not be the same as pricing everybody's monthly energy at $5000 a megawatt hour one month. That's not, I think, what would happen here.

As Michael pointed out, it would also give people incentives to go and hedge this residual risk, do forward contracting, both to hedge the day-ahead risk -- which they can do today -- and they can also now try and write contracts where they put the volume risk or the imbalance risk also on a supplier. All that's fine. But you have to start with getting the spot markets right, and from my own policy view -- perhaps naive -- but I think it's too early to declare failure that we can't do that.

I think we need to try to do that. I think it operates on a small part of the market. There are hedging opportunities for the rest of the market. There can be hedging opportunities for this. I hope it can be viable. I'm certain it's preferred.

COMMISSIONER NORRIS: Sue?

MS. TIERNEY: The only addition I was going to make is, if I thought the world could be decided by economists all the way through, and get it into debits through a stakeholder committee, and get it through financing tools and through the RTO and then into the world and let those prices rip, I would say, this is a great world that you all are describing. It's a world that I ascribe to and wish for. But I don't think that that's actually -- I don't even know who all said the various reasons why that's not exactly the world we live in.

First of all, the first stopping point is the stakeholder process in most of these RTOs. How many times did you guys say, well, we'd like to do this, but we didn't pass it in the stakeholder committee, and therefore we're barred from proposing it to FERC. That's a legislative process determining efficient market rules from the get-go.

So that's the first order, and then it kind of rolls from there. I remember a moment in May 2000-X when there was a very short-term excursion. Whoops. Prices zoomed, huge political fallout.

So of course, sustained high prices are very important. But I think short-term high prices are also politically very difficult for people to live with.

I think we have to look at these other products very aggressively to look -- not just five years from now, but in the transition process to get there. Short term needs to be done right, but there have to be other steps along the way.

COMMISSIONER NORRIS: Jim, I'll give you a short one here.

MR. WILSON: Just real briefly. I think when you're talking about something like ramping, that it's very likely a day-ahead, ancillary service. The RTO is going to want to know how much ramping he actually has for the next day. So we talked about very high prices. It's not necessarily going to be the case.

COMMISSIONER NORRIS: Sue, I totally respect the Chairman's questions of you. I also respect your answers. I also agree with your answer. It's not practical for you not to be a member of the RTO.

MS. KELLY: Thank you.

COMMISSIONER NORRIS: Therefore this residual market we've talked about, and Ed talked about, I'm just curious. It's kind of on the lines of it's not practical not to be a member of the RTO.

Is the FRR a practical resolution for your entities if you just had the fixed revenue requirement, and step out of the capacity auction through that mechanism? It's not used much, so I'm just curious.

MS. KELLY: That's correct. By FRR, we're talking the fixed resource requirement under PJM's RPM, reliability pricing model, just for all the acronym heads here?

(Laughter.)

COMMISSIONER NORRIS: I even used the wrong words just trying to say it out, so I just stuck with FRR.

(Laughter.)

MS. KELLY: And of course, I was not sitting in the room when the original settlement was negotiated. But based on what I know from those who were, including my members, that was developed for one very large entity who had the generation capacity to serve not only all their loads in particular regions, but the reserve requirement on top of that.

My members are not in a position where they can provide 115 percent of their resources right now. I do have members who have embarked on fairly ambitious building programs to try and become more resource self-sufficient, exactly because they've seen what's happened in these markets, and they want to have a physical hedge against these prices.

I mentioned one of them in a footnote in my prepared paper, was AMP, which is doing four run-of-the-river hydro units on the Ohio River. I think it's about 300 megawatts altogether. There's a huge capital investment there. They would not be able to do that if they were subject to a MOPR. They would not be able to finance that. But because it's hydro, a resource that's not covered, you know, well then, that's a possibility.

So they've done that. They're trying to get up to the point where they're basically resource self-sufficient if at all possible, because of what they see has gone on in these markets since their inception. But they are not there now, and therefore couldn't take advantage of FRR, and I doubt that almost anybody else in PJM could either.

Now, I know Duke may have done it at one time. I think AEP has. But, you know, we just are not well-endowed enough with resources right now to be able to take advantage of it.

COMMISSIONER NORRIS: Jim?

MR. WILSON: I just want to briefly note that there are some other models for an opt-out rule in some of your other, more recently-approved RTOs that are more workable.

COMMISSIONER NORRIS: You're getting killed now, go ahead.

(Laughter.)

COMMISSIONER NORRIS: Sue now, and then I'm going to turn this over to Cheryl.

MS. TIERNEY: It was my understanding that that mechanism in PJM -- and Andy and Joe can set me straight on this -- that it could be met by long-term contracting or mid-term or short-term contracting, as long as the LSEs got them firmly committed under a contract, and then moved outside the market. Is that the case?

VOICES: Yes.

MS. TIERNEY: You could keep a lot of near-term resources and long-term resources in the market under that kind of mechanism.

VOICES: Isn't there a five-year period?

COMMISSIONER NORRIS: Yes.

Cheryl?

COMMISSIONER LA FLEUR: Well, thank you.

We have been blessed with fabulous panelists all day. But I think of this as like the Apple genius bar, here to tell us the future given the topic of this panel, which is so forward-looking. It's been fascinating listening to the conversation, particularly Sue Tierney's comment about all the complicated vectors that are shaping the future with the federal legislation, the state legislation, the different business models, stakeholder processes and so forth.

So I'm trying to sort through this. And I want to pull it back a little bit to the present.

I believe that about the only thing that all of your testimony has in common was in some way, shape or form, every single one of you said the capacity markets might not be getting the prices right, for various reasons. You've been sitting here for eight hours. I'm going to ask you to do our job. There's six of you, there's five of us.

Does anybody have any suggestions about what we should do? We could go back to being like the blind man and the elephant, just eight hours smarter, and go back to looking at the specific things, maybe, with a little more understanding. We could let a thousand flowers bloom in the stakeholder processes, and just pray that we're not here in 2020 discussing the New England demand curve and saying, oh, I remember the 2006 conference -- I mean, not us, but our successors.

But on the other hand, when you start thinking of sectionalizing this problem with ancillary services, the issues of the capacity markets, all the things you've talked about, it doesn't fit itself -- it's not immediately apparent how it fits neatly into the various tools that we have.

So I'm interested in, if anyone has any suggestions kind of where either the Commission or where we, as a community of stakeholders and ISOs, start in dealing with this. Because we can't attack everything at once. It has to be viewed holistically, but then it has to be attacked in some kind of sequence.

I'll start with Peter and go down the line, I guess.

MR. CRAMTON: I think the good news is, there's been enormous progress in the price performance of the capacity markets. If we do think way back to the first capacity markets, they were absolutely dreadful in terms of the prices that got spewed out. They were often zero, but very occasionally quite astronomical, and it was because there was no ability -- you know, first the product was very poorly defined, that you didn't have any obligation to do anything. And second, it was just a spot signal with a vertical demand curve, and you've got a vertical supply curve. And so we know that markets, both vertical supply and demand, are not going to lead to really attractive prices.

So what we've done since then is, we've had sloped demand curves in most of the markets, and that's a good idea. New England certainly proposed a sloped demand curve. It was just the settlement that eliminated it. So I think that there's strong agreement that the sloped demand curve is going to improve the prices.

Why does it make sense? Because, in fact, what is a demand curve? It's a representation of the marginal value that the demand side is getting, and there is marginal value to additional resources in terms of reliability. And that's the theory behind the sloped demand, and it makes a lot of sense and should be done.

The other thing that we did was have capacity markets be a forward market, many years forward, so that new entry could compete with existing entry without having all the costs on. In some of the markets, a longer-term lock-in for the new capacity with respect to the market clearing price. New England has that, and New York and PJM do not.

Around the world, other markets have the long-term lock-in, too, for new entries, which I think is quite desirable. Because that gives us more reliable price information that's coming from the cost. Essentially, this is a procurement auction, so that price information would be coming from the supply side, and that's going to be their cost. And so, you need to have suppliers that haven't yet sunk all their costs, and for units that are deciding whether or not to retire, again there's going-forward costs that aren't yet sunk, so you get reliable price signals there.

I think when you have strong performance incentives, then again you're going to have better price information, cost-based price information, reflected in the bids. On the demand side, that's necessarily going to have to be administrative, but logically should have some slope -- although as we've seen, one good thing the capacity market has done is, gotten a lot of demand-side participation.

So, demand side is participating. They're participating with their negative supply, which is being valued appropriately. I think progress has been made. We just need to do more of it.

COMMISSIONER LA FLEUR: Do you think that, from your observations, the stakeholder processes are just pushing toward those improvements as they go along? Or do you think there's any element of this that the Commission should bore in on and say, well, we're going to look at the long-term lock-in or need for more ancillary services for balancing renewables and start doing a piece of work on that?

MR. CRAMTON: I think there's a critical role for the Commission to exercise leadership in these market design issues. Because we know that the stakeholder process is not a perfect process for market design.

MS. TIERNEY: Let's vote on that.

(Laughter.)

MR. CRAMTON: You know, it's very important for people to have voices and so on. But there are sensible, logical market design elements that need to be promoted by the Commission, and I think that's an essential thing that will then mitigate some of the problems with the rent-seeking that are inevitable in the stakeholder process.

COMMISSIONER LA FLEUR: Thank you.

MR. HOGAN: I'll interpret your question as being, if that's the way you see the future, let's think about what we can do, like today.

COMMISSIONER LA FLEUR: That's a much better way of saying what I was trying to say. If that's where we're going, but we don't know where we're going, but there's a range of possible outcomes, what do we do first to make it less painful when we get there, or less painful today for people who think it's broken today?

MR. HOGAN: As someone who has spent most of my professional career as an investor in generation and an owner of generation, only recently converted to a talking head, I will sort of second comments that were made earlier in the day that, in the end, the most important commodity for investors is confidence. I completely agree with the comments from the RTOs that how far forward, how long a commitment period, is not all that really important.

COMMISSIONER LA FLEUR: What was the most important?

MR. HOGAN: Confidence.

COMMISSIONER LA FLEUR: Confidence?

MR. HOGAN: Confidence that they're not going to be whipsawed into a completely different market design tomorrow.

With confidence, the PJM model can work, the New York ISO model can work, even with its vertical demand curve, perhaps the ISO New England model can work, although they'd be much better off with a sloped demand curve. But that sort of leads me to say that, you know, we can all dream about what we'd like to see the world look like in five or ten years. The focus for the moment probably should be on incremental improvements.

Frankly, I think our view is that, although they're certainly not perfect, the current capacity markets, in dealing with the world as it is today and was yesterday have probably not been wildly off-base in terms of the results. We just think that the way the world is going to be tomorrow is not going to do the trick.

So how do you start dealing to prepare for that? First of all, I completely endorse the idea of getting more reliable real-time pricing in the energy and services markets. It should be a priority, and there are lots of things that can be done that are being done in some of the RTOs to deal with that.

Then secondly, and we deal with this in the paper, we can start by a more structured initiative to begin to forecast net demand in the regional systems. Because if the net demand issue -- for those who aren't familiar with it, net demand is what you're left with after you deduct zero marginal cost, must-run variable resources -- it's what the rest of the system is left to deal with. And that's really what drives this concern about flexibility.

And we can debate until the cows come home whether, you know, we need lots and lots more flexibility next year, or next year's going to be okay but we need lots and lots more flexibility by 2020. We don't know until we start forecasting.

So before we go jumping around making big changes to the market, the first order of business should be, I think that it would be well-advised for the Commission to ask the RTOs to do a more deliberate job of forecasting net demand. And that would incorporate not just growth in variable resources, but also energy efficiency, growth in demand response, growth in different types of demand response. And perhaps most devilishly difficult, growth in distributed generation -- behind the meter, FUD, and that sort of thing.

All very difficult, certainly; arguably no more difficult than forecasting the need for peak resources. Certainly, no less prone to being wrong, but you've got to start somewhere. So I think we would say that's a good place to start.

COMMISSIONER LA FLEUR: Thank you. Sue number one?

MS. KELLY: I guess, you know, we all come at this from our perspective. I came at it from a FERC lawyer, and I'm thinking, what is she asking? Do we do a rulemaking, do we do this, do we do that?

COMMISSIONER LA FLEUR: That is sort of what I was asking.

MS. KELLY: I thought that might be where you were going.

COMMISSIONER LA FLEUR: Following Commissioner Norris's comments, I don't want to terrify everyone.

(Laughter.)

MS. KELLY: I'll tell you what would terrify me, which is the mother of all rulemakings on standard capacity market design, that says we're going to adopt best practices.

COMMISSIONER LA FLEUR: I guarantee that's not what it'll be called.

(Laughter.)

MS. KELLY: That would really scare me, and many of my members.

COMMISSIONER LA FLEUR: Those words don't even come out of the FERC computers any more.

MS. KELLY: For example, I have members in New

York who kind of think that things are generally not so bad there, and would hate to be dragged into a world they never made, you know. So let me just get that out there.

COMMISSIONER LA FLEUR: They might also be quite unworkably broad and huge.

MS. KELLY: The mother of all rulemakings. I don't think you want to do that.

On the other hand, and I want to expand upon this in, hopefully, the written comments that you'll allow us to file after, because I haven't talked about this with my members, and I don't want lightning to strike. But another possibility might be to think about a policy statement where you could just kind of ask for comments on certain broad themes, and maybe based on that ask RTOs to consider certain issues and how best to address them. Because I do have to agree that the stakeholder process, without any white lines to be driven in, can be death of a thousand resource cuts.

My members don't have the same resources to participate in those processes that many other sectors do. So just sending us off to endless stakeholder death is something I would really beg you not to do. And again, the mother of all rulemakings scares me as well.

Subject to further thinking and comment, maybe some kind of policy statement, asking to consider the kinds of issues we've raised today, might be an idea. But, you know, no warranties, express or implied.

COMMISSIONER LA FLEUR: Thank you. Caveats accepted. Mike?

MR. SCHNITZER: Well, I can't play FERC lawyer at all. But I think the idea of assuming you're going to invite post-technical conference comments, of making that among the things you're soliciting comments on, would be helpful, and I think you would get a lot of suggestions -- maybe more than you'd like -- about how best to proceed, or which pieces. So I think that would be a good place to start.

I think we heard today from each of the RTOs, not just the status, but their agenda, right. Their development agenda, they were all laid out I think in the first panel. And so you will have to form your opinion as to whether those sound good to you, and whether they're best prosecuted, you know, through the windowless room stakeholder process in each of the RTOs, or some other fashion.

From my observation, again, I would say that common on everybody's to-do list that we heard this morning from the RTOs was, scarcity pricing in the energy and ancillary services markets. To which I would add, reducing the contribution of uplift in real-time markets, and getting uplift into real-time price formation as well. I think that was a common issue that was identified by all three of them this morning, and however that's prosecuted, I think that should be high on the list. Even though it's not a capacity market per se, I think it has a lot to do with what we're doing here.

Then as I said in my statement, which I won't repeat in detail, but I think that there are, as you heard this morning, there are some important clean-up issues to be dealt with on eliminating price discrimination and dealing with price discrimination. That's not just the dreaded MOPR kind of a thing. It has also to do with new entry price assurance. It has to do with this conversation on the granularity of the capacity markets, and if you give somebody an RMR contract, are you discriminating against some other generator who is meeting the same reliability need and you just couldn't see it, because, you know, your markets were not granular enough.

I think there's a set of issues there that I think should have a high priority, including the interplay between transmission into a load pocket and new entry in the load pocket. You know, Bob described this circumstance, I think, in the Boston load zone about the new entrant, and the price was talked about. But what wasn't mentioned was that on the transmission plan is a set of investments which will de-bottleneck that constraint.

So trying to build new capacity into that is an issue. And CONE calculations that are based on a 20-year levelized cost are not particularly appropriate when you might only have four or five years until the transmission policy changes. And now you've got a different problem, but you need the capacity today.

So these price discrimination issues arise in a number of situations, and I think we ought to continue -- somebody used the term, cleaning them up. I think we ought to continue to clean those up.

COMMISSIONER LA FLEUR: Thank you. That's very helpful.

MS. TIERNEY: I like the idea of some kind of policy statement, too. Here's an example of the reason why.

A couple of months ago, I participated with a group of state commissioners in the northeast, where the purpose of the conference was to try to vision what they were all aspiring to in terms of their policy goals, and then to back up the administrative proceedings that it would take to actually take up all the dockets that would change the rules that would effectuate the entree of the various resources they saw.

It didn't add up. You couldn't get there fast enough for the time frame that they thought about. So I'm thinking maybe some combination of a visioning thing in a policy statement -- what are some of the implications of these goals -- and what does that mean for urgency and examination of issues.

I could imagine, as part of that, however loth you are to do it, you might do an analysis or two. One analysis would say, if you looked at short-term markets and they were priced at this under these kinds of reasonable scenarios, does the money add up to keep resources in the market, every single quarter that shareholders are looking at quarterly returns, sufficiently to get to the time frame that you have changes in the market five years out that are addressing some of these issues.

Does the money add up? I don't know if it adds up in that frictionless world. In the real world of course there are these time constraints of the very stakeholder processes, your dockets, investor decisions, permitting requirements. And so if you looked at a sticky world, a constrained world, do the numbers add up when it's actually more expensive and more difficult than it is in a frictionless world?

I don't know if you guys have that kind of modeling resources. But if so, it might be interesting.

COMMISSIONER LA FLEUR: Thank you. Mr. Wilson?

MR. WILSON: I share your sentiment in your question, about are we going to be here in 2020 discussing these same things. And I think in anything we do, it probably would be useful to kind of raise the question of, where do we really see the role of the capacity market going. And my view is, you really want it to shrink over time.

We've talked about how the energy and ancillary services markets should be further developed, of course. The more revenue there is there, the less you would have to have in the capacity markets. And on the other end, you want the bilateral markets to live again to rise again. Long-term resources like a new power plant or a major rebuild to an existing power plant -- it's a long-term resource, and it's naturally supported by some kind of long-term commitment on a bilateral basis.

So if you have both of those, energy and ancillaries, in a bilateral market, the role of the residual spot capacity market, sitting between them, can be small. And I think you ought to start that conversation, of whether that's really what you want to be shooting for.

To the extent you have -- a residual spot capacity market is most efficient if it's held close to the delivery year, when it can be more or less deciding short-term resources like demand response, like a power plant that can either run another year or two or retire. There are a lot of resources like that. It's over half of the incremental capacity cleared in PJM, is that sort of short-term stuff for which a one-year spot capacity market signal is decisive, compared to a new power plant.

So to the extent you have a three-year forward process, I recommend that you focus on having that be efficient in terms of between the three-year forward and the incremental auctions closer to the delivery year. You want market participants to be able to come in, to be able to come out. You want price convergence between those different markets,

So I'm glad to hear that you're not going to call it standard capacity market design. I guess that suggests you already have a name for it.

(Laughter.)

COMMISSIONER LA FLEUR: No. The first thing we need to do is go off and confer and distil all this. Definitely there is no name, because there's not even a thing to be named.

But I think standard market design is a name that is in living memory.

(Laughter.)

COMMISSIONER LA FLEUR: But I thought all your comments were really helpful, and it does point to the power of naming, in the sense that if we'd called it a future reliability insurance product, and ancillary services were called necessary services to keep electricity -- I mean, ancillary sounds so small, and capacity sounds like it's the thing. There is some power in some of these.

Michael?

MR. HOGAN: There was one thing I did forget to mention, and I think it is very important, and it's a caution.

There's been talk about pricing emergency DR differently at various points throughout the day. However you feel about tranching in the capacity market, that is a slippery slope to tranching. Because functionally, emergency DR is exactly the same as a peaking gas turbine, functionally. And yet, there's a limit to how much you want either of those types of resources in your portfolio. Guess what? You have a tranche.

Just as baseload and energy efficiency are functionally exactly the same type of resource, and there's a limit to how much baseload resource you want in your portfolio, guess what; you have a tranche. So before anyone considers going down the road of differentiating pricing for emergency DR, think about that. That is a slippery slope to tranching in the capacity markets, which may or may not be a good thing.

COMMISSIONER LA FLEUR: Thank you.

Mr. Moderator?

MR. DENNIS: Thanks very much to everyone.

Just to wrap up quickly, in response to some of what you said, we do plan to receive post-technical-conference comments. The form of that is to be determined, as Commissioner LaFleur said. So look out for a notice from the Commission seeking those comments.

Otherwise, than you to everyone who participated today. Thank you to everyone that came to listen. And let me turn to the Commissioners for any closing remarks.

COMMISSIONER CLARK: Thanks to everybody -- for kind of regulatory geeks, it's not often that we all sort of get to get in the same room and pick some of the brains of the smartest minds in the country on some of these issues. So I appreciate that. Because I assure you, when I go to my Cub Scout meeting tonight or hockey practice tomorrow, there's not a single person who will want to talk about any of this.

(Laughter.)

COMMISSIONER LA FLEUR: I also just want to thank everyone. I thank all the panelists for all their work on it, and for really keeping it real. I think you framed a lot of issues, big issues and small issues, that we have to go back and think about.

I just wanted to thank the staff -- everyone, but especially Jeff, Jamie, Julie, all the Js, and Shiv, for all their work on this. Hopefully, I got the right folks --Kate and Ray and everyone -- for their work on the paper and pulling this together, because it was a lot of work in August. So thank you.

COMMISSIONER NORRIS: I as well -- very thoughtful comments from everybody. It was very helpful. The discussion today was helpful on top of that. So I really appreciate your input.

Special thanks to staff. I know this was a lot of work the last few months for you all. So I appreciate. I'm sure you all have got a place to go in about three minutes, probably --

(Laughter.)

COMMISSIONER NORRIS: I won't even ask you where, but thank you.

MR. DENNIS: Thank you, everyone. I think we're adjourned.

(Whereupon, at 4:59 p.m., the technical conference was adjourned.)