BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Nos.

FORWARD CAPACITY MARKETS : AD08-4-000

IN NEW ENGLAND AND PJM : ER08-633-000

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Commission Meeting Room

Federal Energy Regulatory Commission

888 First Street, NE

Washington, D.C.

Wednesday, May 7, 2008

The above-entitled matter came on for technical conference, pursuant to notice, at 9:00 a.m., Kevin Kelly, presiding.

P R O C E E D I N G S

(9:00 a.m.)

MR. KELLY: Good morning, everybody. Welcome to the Federal Energy Regulatory Commission. I'm Kevin Kelly, Director of the Policy Analysis and Rulemaking Division in the Office of Energy Markets Regulation.

This is the Commission Staff Technical Conference on Capacity Markets in Regions With Organized Markets.

We have Commissioner Jon Wellinghoff and Commissioner Marc Spitzer at a side table, and you may find that some Commissioners may be joining us throughout the day, or may watch this Conference on closed circuit from their offices.

So, it's important for all of us to speak into our mikes. The Conference is also being recorded and being transcribed.

The purpose of the Conference is to discuss the operation of Forward Capacity Markets in ISO New England and PJM, and to learn more about two novel proposals, one from the American Forest & Paper Association, and another from the Portland Cement Association, and others.

These are proposals for dealing with current issues. They were submitted to the Commission in response to the June 2007 Advance Notice of Proposed Rulemaking, on Competition in Organized Markets.

We want to know how the existing forward capacity markets are operating and the merits of adopting changes such as these two proposals.

The Technical Conference will go all day till 5:00. It's composed of five panels: The first explains how the existing PJM and New England capacity markets work, with additional commentary from the two representatives of state regulators.

The second panel presents the American Forest & Paper proposal, and the third, the Portland Cement proposal, and commentary.

After a lunch break, we're going to have two sessions, each an hour and 45 minutes, with many points of view on the topics presented in the first three panels, with the exception of the four presenters of the four models, who will speak for 15 minutes each, everybody else will speak for about five minutes, so that we have adequate time for discussion among all the participants.

Before we do, I'd like to have the Commission Staff around the table, introduce themselves, starting on my far right.

MR. AGERWALL: Kumar Agerwall, the Office of Electric Reliability.

MR. O'NEIL: Dick O'Neil, with Energy Markets.

MR. MEAD: David Mead, from Energy Markets.

MS. HAM: Tina Ham, Office of General Counsel.

MS. McKINLEY: Sarah McKinley, External Affairs.

MR. KELLY: Let's get right into it. On your program, you will see that we have listed Commissioner Butler first. He has requested not to go first.

(Laughter.)

MR. KELLY: So we'll first hear from Mr. Ott, Mr. LaPlante, for 15 minutes each, then we'll hear from Commissioner Butler and Dennis Bergeron.

Andrew Ott is Vice President for Markets, PJM Interconnection. Andy, it's all yours.

MR. OTT: Thank you. Good morning and thank you for the opportunity to speak in front of you today on the issue of forward capacity markets.

My comments today will briefly cover the theory and workings of the RPM construct, including some of the major components and some of the drivers that were integral in making RPM go through the stakeholder process.

The issue of outcomes, how the RPM model is working, I will make comments on what we've seen to date, as far as the RPM auction results. I must emphasize, however, that it is premature to draw definitive conclusions about the forward capacity market and how well it's working of working as intended, simply because it's only been in place one year.

In fact, we're running an auction this week, and accepting bids for the next auction that will clear next week, so I'll keep you all informed and the Commission well informed on what those results are.

But, again, it's premature to draw a definitive conclusion. As you know, PJM is responsible, as a regional transmission organization, for keeping the lights on.

Keeping reliability and grid operation in sync, if you will, after market issues, is a difficult subject. We have spent several years within PJM, trying to develop a construct that would replace our existing construct -- at that time, existing construct.

The primary driver, again, behind this seven-year discussion, was projected reliability concerns that we had seen within the structure and in investment, and the lack of new entry coming into the markets.

The other thing we had observed during the 2004 to 2006 timeframe, was an increasing amount of retirements. Again, retirements, in and of themselves, are not a bad thing. It was retirements of generation in areas where it was still needed for reliability.

So the issue was, the retirements were occurring in areas where generation was still required. We looked at the main drivers of RPM. It was essentially a lack of new capacity, the short-term notice retirements that were requiring PJM to enter into individual reliability must-run contracts.

So there was inconsistency between capacity, price, and reliability requirements. We're seeing very low capacity prices in areas where we have a need for even more generation, rather than less.

We saw a reduction in demand-side response in the capacity markets over the years. We essentially saw a lack of forward investment signals, if you will. There was no forward price to show folks what was going to happen in the future, so, as we identified the future reliability violation, the only notification members got, was a notification on our website, which said we're going to have a future problem.

So this really came to a head when we saw throughout 2008 to 2010, saw some very significant and building reliability concerns, which we had testified to in the previous forum, and I have attached some of that material to my testimony for your reference.

Let me turn now to the key design features of RPM. We had a three-year forward auction, which was essentially to show this price signal, and the forward auctions were to provide information, transparent information, to the stakeholders about the state of the system into the future.

They obviously were not to replace forward bilateral contracts; they were to incent more of them to occur. And they were to differentiate between areas of the system where we had adequate capacity and areas of the system where we didn't, because there were locational signals, essentially, and that was one of the other main features of RPM, was to actually have locational capacity constraints, which we did not have in the past.

That allowed us to tie the RPM design to the regional planning process, so the regional planning process would identify important constraints into certain areas, and feed that into the auction.

Then what we saw in the first few auctions, were higher capacity prices in certain areas, because those areas were import-limited.

The last main feature of RPM, again, was the variable resource requirement curve, which is essentially a demand curve, if you will, a sloped demand curve that allowed us to manage the volatility, if you will, of the RPM clearing prices, and also acted as essentially an overall cap on price, based on the cost of new entry.

The ability of the forward auctions, also provided the ability of demand response and the transmission solutions to the peak with generation into the future.

The forward auction design also allowed new entry to directly compete to set the price into the future, which did not occur in our previous auction.

In the remaining time I have, I'll make some comments on what we've seen to date, as far as the RPM results.

In my materials, I have a few tables. I didn't put the slides together, but I'll make some reference to some of the graphics you have in front of you, within my presentation. On page 5 of my discussion, I listed a table of the clearing price results for the first four auctions.

These four auctions, I must emphasize again, were all run within the one-year period between last May and today. We had what we call the transition period, I think, as part of the settlement, to implement RPM.

These auction were run roughly every two or three months. We were running another auction for another year, into the future.

The first one, I'll call non-transition auctions, that we're going to have, as the one running this week, for the 2011-1012 period. That will be the first three-year forward auction.

If you looked at the prices in the auction, you saw in the unconstrained area system, what we call rest of RTO. The price started out at $40 and then increased as the supply access, if you will, decreased in the system.

What we saw, was that the total amount of generation coming into the system, did not keep up with load growth in those early auctions. That's essentially why you saw the price increasing in the broad RTO.

In some of the other areas, the constrained areas of the RTO, the prices were higher than the rest of the RTO area, because we capacity import limits.

Those have abated over time. In the last auction, in fact, we had an unconstrained situation. Some of that was due to the fact that we had some incremental transmission upgrades, and some of that was due to the dynamic of the demand curve and the supply curve.

If I could turn to demand response trends, back on page 6 and 7 of -- actually, the graphic is on page 7. I mentioned before that we had a decrease in participation prior to the RPM.

If you looked at the graphic, what you saw, again, was a decreasing trend as we looked further into the past. You still see some additional decrease of participation of demand response, as to capacity.

Back before RPM, it was called ALM, and we had to have a new acronym, so now it's called either DR, which is the demand resource, or ILR, which is interruptible load reliability.

The difference between the two under RPM, is that the demand response DR, actually bids in on a forward basis and affects the clearing price. The ILR is something that's done later, as we go into the delivery.

You can see the amount of demand response we've gotten, has significantly increased with the implementation of RPM, so that trend of decreasing demand response, has actually been reversed.

Dealing with capacity imports and exports, I have a discussion on page 8. We did see an increase in the amount of capacity coming into PJM, versus what was being exported, again, largely in response to some of the capacity clearing prices.

If you look at new generation, additions, and upgrades, I created a table for you on page 11 of my discussion. One of the common questions we get, is the differentiation between actual new, physical units, where you have a new generator, versus a reactivation of a generator that had previously been retired or mothballed.

The other question is, an upgrade to existing plant, where some technology improvement or inlet cooling or something will increase the capability of the unit. The table breaks all that down for you, so that you can see the various types of entry.

Again, the total new units across all the auctions, was 1,036 megawatts; the reactivation was 348, the net upgrades to capacity, was 2889.9, and that's a total of about 4300 or 4400. Essentially, I will put through each of the tables, but if you have questions on those, I can certainly answer those.

Then the next area I want to just comment on, is, people had asked me to discuss the total RPM impact to date, so I tried to distill it down into a table. And if I look into the future, say, if I look at 2010, 2011, you remember what we were facing before.

We were facing decreasing generation, because they were retiring, we were not getting any new stuff, and the demand response wasn't coming in. I think that if you look into the future, you're saying, well, we had some new generation for 2010, 2011; we had incremental upgrades, you had summary activations, and, again, demand response was coming in now on a forward basis, and then, of course, the cancellation of the requirements, also contributed.

So we look at all those impacts together for 2010, 2011, and the impact comes out to be 11,817 megawatts. Again, I tried to break that down, so you can see each of those effects.

So, when folks ask, is RPM working, my answer is, I don't know. It's a forward capacity market, and it's only been in place a year, and this next auction will be critical, because it's the first forward auction, and certainly we'll get a lot of information out of it.

We have seen some positive things. We've seen a reversal of the retirement trend; we've seen more demand response; we've seen a fair amount of incremental upgrades to the plants, and we've seen some amount of new entry, but I certainly can't sit here and call it a success, but certainly there are some positive trends we've seen.

Certainly now, there's been a valid discussion about the overall costs of capacity markets, in general, and I think that we can certainly have much discussion on that today, but, in summary, I will comment that PJM does expect, as it put in its testimony, to have an evaluation of the RPM model completed towards the end of June of this year.

The Brattle Group is actually working on an analysis of the various features of RPM. They are interviewing stakeholders to get stakeholder input on the various aspects of RPM. We expect to have a report to come out on June 30th.

Obviously, we'll provide that report to the Commission, and we'll have a stakeholder discussion following that, to do further evaluation. With that, I'll be happy to answer any question you have.

MR. KELLY: I think we'll hold questions until we've heard from all the speakers. The next one is from ISO New England, David LaPlante. Welcome back. He is Vice

President of Wholesale Market Strategy with ISO New England. He has a PowerPoint. I think our AV people will put it up on the screen shortly.

(Slide.)

MR. LaPLANTE: Good morning. Thanks for the opportunity to participate in the Conference. While we were getting ready, I had a bit of a flashback and thought I was in the settlement discussions, but it passed quickly.

I wanted to start out with an overview of the need for capacity markets, describe some of the key aspects of the New England capacity market, and talk about the results of the first auction, what we're seeing in preparation for the second auction, and finish up with some observations on how well we're doing and where we're going in the future.

(Slide.)

MR. LaPLANTE: Seeing we're going to be discussing other proposals, I wanted to talk for just a moment about the need for capacity markets. It goes back to the missing money problem.

In most markets, we recover the cost of investment when the price exceeds the cost of production. That's something -- and this happens a lot during shortages. As I note here, hotel prices during vacation seasons, I'm sure, are pretty important to the hotel industry in paying off their debt.

Unfortunately, this dynamic does not really work in electricity markets. Prices are mitigated $2,000 a megawatt hour, and we design our systems to have few hours of shortages, to maintain reliability.

We have both planning and operating reserves, so we don't end up in shortage a lot. Particularly marginal units, have trouble recovering investment, so we've come up with capacity markets as a way of solving this problem.

(Slide.)

MR. LaPLANTE: Turning more to the New England market, what are the objectives of the New England market?

Simply put, it's to meet reliability needs at the lowest cost, through markets, and what FCM does to do that, is to purchase New England's requirements, three years ahead of time.

It also procures enough capacity in each subregion, to meet local needs. The market piece of it, is really two key pieces: One, we're promoting investment with the ability to sign up to a long-term contract of five years. This is one of the important design principles, I think, that got people to agree on a settlement, is, that we've gotten new capacity resources setting price from the auction.

(Slide.)

MR. LaPLANTE: What is capacity? What are we buying? We're buying physical capacity in a specific location, for demand response.

It's a key piece of the whole settlement and design. That capacity has to be offered in the day-ahead and real-time market, every day, and if they are not available because of an outage, we have to be notified of that, as well.

Resources, of course, must follow dispatch instructions. One of the advances in this capacity market design, is that there is an energy call option associated with capacity, even though it's at a high price.

If the resource is delivered, then we will meet that reliability need, so the energy call option protects load from very high prices and maintains reliability.

(Slide.)

MR. LaPLANTE: Procurement mechanism -- how are we buying the capacity? We're buying it through a descending clock auction with multiple rounds. The auction begins at two times the cost of new entry, and then bidders, obviously, offer in what they want to provide at that price, and the price is lowered each round.

And if more resources are bid in than required, the price is lowered and resources exit the auction. We keep dropping the price until the supply equal demand.

What we've got at the end, hopefully -- and we do -- is that only the required amount of resources are left in the auction and we've purchased the capacity we need at the lowest price possible.

(Slide.)

MR. LaPLANTE: Then payments begin about three years after the auction. As I said earlier, new capacity has an option to select up to a five-year commitment to reduce investment risk.

Where existing capacity receives the auction price each year, this avoid an existing capacity having to worry about trying to get a long-term commitment, depending upon the price.

(Slide.)

MR. LaPLANTE: There are two important performance incentives built into the FCM structure: One is the capacity resources payments are reduced, if they are unavailable in capacity shortages, capacity shortages, as in times when we're short of operating reserve on the system.

If resources aren't available during those time periods, payments are reduced at a minimum of five percent for each instance. That can go up to 10 percent if it's an extraordinarily long outage.

If we had an eight- or ten-hour heat wave related event, a resource could lose 10 percent of its capacity payment for the year if it were unavailable during those hours.

The energy option is an additional performance incentive. If the energy price exceeds the cost of a heat-rate peaking unit, with a heat rate of 22,000, that money, the difference between 22,000 heat price, about $220, in ten-dollar gas, and the energy price went up to the cap of a thousand dollars, that $780 would be subtracted from the capacity payment for each megawatt, so capacity payments are reduced to generating resources.

This doesn't happen on the demand side. It's sort of a footnote, therefore, if a generator doesn't perform, they not only lose a percent of their overall payment, but they don't earn the peak energy rents.

(Slide.)

MR. LaPLANTE: Turning to the results of our first auction, we held the first FCA over a three-day period in February. We met -- actually exceeded, the amount of capacity we need to meet needs in 2010 and 2011. Mechanically, things went successfully; we had no technical problems and we observed no anticompetitive behavior.

So, there was a lot of work that went into the preparation of the auction, and we're glad that it went well.

Prices started out at two times CONE, which was

$15. They dropped down to the floor price of $4.50 a kilowatt month, and we, even at the floor price, we did have 1800 megawatts of new supply and demand resources coming onto the system.

(Slide.)

MR. LaPLANTE: This is a breakdown of the resources by type and by location. There's about 1188 megawatts of new demand resources.

Those resources are split almost perfectly in proportion to the load in the region, with about half in Massachusetts, a little less than a quarter in Connecticut, then smaller amounts in the other four states.

In addition to the 1188 megawatts of new demand, there's another 1100 or so megawatts of existing demand resources that are also in the system, so we've got about 2200 megawatts of demand that cleared in the auction, that will be part of the supply mix in 2010 and 11.

In terms of supply resources, we have about 626 megawatts. That was more concentrated in Connecticut and in Massachusetts, than the other states.

(Slide.)

MR. LaPLANTE: In terms of the fuel mix of the supply resources, mainly gas resources. There were a couple of nuclear upgrades and some small wind and hydro plants that cleared the market, as well.

(Slide.)

MR. LaPLANTE: This table shows the starting and end prices for each round, and one point I'd like to make on this, is, if you look on Round 1, under the excess at the start, we had over 6100 megawatts more than what we needed to show interest in the auction.

That's a fairly robust amount of capacity showing interest, which indicates to us, competition and FCA was attracting interest. If you look at the end, Round 8, under excess at the end, we had about 2,000 megawatts more than we needed to meet our IPR.

That happened because we hit the floor price of $4.50. These are the settlement discussions. A collar was agreed to. We had a little over $10 at the top and about $4.50 at the bottom. We hit the $4.50 at the bottom.

The other point is that load will pay $4.50 times the IPR. The payments to load are prorated down, or payments to generation are prorated down to the surplus, so the total load exposure is $4.50 times about 33,000.

(Slide.)

MR. LaPLANTE: We're preparing for the next auction, which will be held in December of 2008, and we actually have more interest in FCA-II, than we had originally in FCA-I. There's about 15,800 megawatts of new resources showing interest, a little over half in generation, including a little less than 600 megawatts of wind generation in northern New England.

But, again, the primary source of new generation, the fuel source for new generation, is gas-fired combined cycles or gas-fired combustion turbines. There are some hydro and fuel cells, but much smaller amounts; a significant amount of imports.

We only have about 4,000 megawatts of import capabilities, a little less than 3500 megawatts of import capacity, so there will be competition to get the capacity in over those ties.

We have a significant amount of new demand resources, as well, 1700 megawatts more demand for the showing interest.

(Slide.)

MR. LaPLANTE: At this point, we think that the market seems to be working as designed, although, as Andy said, these are forward capacity markets. We're looking out over a long period of time, but the interest we've seen, indicates that it's a viable structure to attract investment in the region.

We enable demand to participate fully in the market, which was an important part of the design. Very importantly -- and we haven't talked a lot about this -- we've reduced the number of reliability agreements in New

England -- we will reduce, rather.

There's over 3,000 megawatts of reliability agreements in New England now. At the end, in 2010 and 2011, we will have about 350 megawatts of reliability agreements. That's a significant improvement to the market, and, I think, is a benefit to the consumers in the region.

We do have a locational component to make sure we have the capacity where we need it.

(Slide.)

MR. LaPLANTE: What's ahead for FCM? We've got a number of significant projects we're working on. One, we're integrating the forward capacity market in the interconnection queue.

There's been a concern by some that higher queue positions will block out more economic projects. We're trying to come up with a bit more flexibility in letting projects that are more economic, stay in the auction and get built, to have a lower interconnection queue position.

That's something we'll probably be bringing down to the Commission in the Fall. We're almost completing rules to compensate resources that wish to de-list, but are needed for reliability.

That's replacing the old cost of service as the only option for our agreements, and that's something we will be bringing down to the Commission in July.

One of the biggest challenges we have operationally, is incorporating large amounts of DR into the grid. The DR that cleared in FCA-I, is about seven to eight percent of our total resources, and if all of the DR in FCA-II clears, we could have nine percent active DR; 13 percent DR, overall, so we need to look at the tools we have to dispatch.

We also need to look at the dispatch rules and protocols, to make sure that they all work, so that we can maintain reliability with the demand resources. There's still a lot of work to do to complete the design for the settlement.

In the settlement agreement, we've got to design our settlement system and a number of other details, and, finally, the settlement agreement included a review by the market monitor, after the second auction, and we'll take a look at the design at that point and see what sort of improvements we can make to it. Thank you.

MR. KELLY: Thank you, Mr. LaPlante. Next, we're going to hear from Commissioner Frederick Butler, from the New Jersey Board of Public Utilities. Welcome. You have a long and illustrious history with NARUC, which I won't recite.

COMMISSIONER BUTLER: Thank you, Kevin. Good morning, everyone; good morning, Commissioners; good morning, members of FERC Staff.

I do serve as a Commissioner on the New Jersey Board of Public Utilities. I'm also privileged to serve as First Vice President of the National Association of Regulatory Utility Commissioners, and I'm a member of the Board of Directors of the Organization of PJM States.

However, today I'm here speaking only as a Commissioner from the New Jersey Board of Public Utilities. I want to thank you for convening this Technical Conference to discuss the operation of forward capacity markets in New England and the PJM Regions, such as PJM's reliability pricing model.

This Conference follows the Commission's recent decision to reject PJM's proposal for a substantial increase in CONE, the cost of new entry, and the Commission's Order requiring PJM to expand the scope of its analysis of RPM.

All these developments are promising signs of the Commission's willingness to investigate costs and results of RPM and other forward capacity markets, and, therefore, to fulfill the commitment that Chairman Kelliher made to New Jersey Senator Robert Menendez, about a year ago, when the Chairman promised, and, I quote, that the "FERC will closely monitor the implementation of RPM through a series of detailed reports, and the FERC's continued oversight of the market within PJM, to determine if RPM was living up to its objectives, and to evaluate any necessary changes," end quote.

That close monitoring and oversight, depends upon the Commission and Staff bringing their more than ample knowledge and insight to bear, as they investigate and evaluate RPM's design and the results.

After the fourth base residual auction under RPM was held a few months ago, my friend sitting to the left of me, Andy Ott, said the following, which I think is a quote, and I'll stand corrected, if it's not:

"Looking at the combined results of the four base auctions, commitment, in the case of capacity, was 10,000 megawatts, compared to what would have been available, absent RPM. In other words there will be 10,000 megawatts of capacity rating to keep the lights on for consumers, that wouldn't have been there without RPM," end quote.

Putting aside for the moment, the lack of a firm basis to claim that none of the net increase in capacity would have appeared without RPM, it will nonetheless be helpful to review that net increase of 10,000 megawatts in the context of the Commission's stated concern that, quote, "appropriate price signals be available to provide incentives to construct facilities necessary for regional reliability," end quote.

In approving the RPM settlement, the Commission had hoped that RPM, and, again, I quote, "would provide a just and reasonable replacement for the existing construct, by creating financial incentives within the context of a market system, to encourage investment in additional infrastructure, in the locations where they are needed," end quote.

The answers to the following questoins, will help the Commission put the results of the first four base auctions, into context: First, within PJM, new generation is most urgently needed in eastern MACC and southwestern MACC, which are at the core of PJM's portion of the mid-Atlantic critical congestion area, that the U.S. Department of Energy identified in the 2006 congestion study.

The question then becomes, how much of the net increase in capacity is located within eastern and southwestern MACC?

The second question is, within eastern and southwestern MACC, how much of the net increase in capacity is new generation and how much comprises older, inefficient power plants that have previously been scheduled for retirement?

The answers to the questions above, will help to demonstrate whether RPM has been effective, to date. Answers to additional questions, will help to demonstrate whether RPM is fulfilling Chairman Kelliher's promise to the

Senate Energy and Natural Resources Committee, specifically that, quote, "Rather than simply rewarding existing generation, RPM will encourage entry by new generation," end quote.

The additional questions, therefore, include: How much capacity revenue will result from the first four auctions, and, of that amount, how much will flow to new generation in eastern MACC and southwestern MACC?

How much will go to existing generation throughout PJM, that have not notified PJM of their intention to deactivate, excluding, of course, any plans that were proposed to deactivate in PJM, only to reactive it in another RTO?

As an aside, the ability of a generator to do just that, deactivate in PJM, only to reappear the next day in another RTO, without significant and required mitigation of the effects of that withdrawal, is a very important seams problem that the FERC needs to address, maybe in another proceeding, but I urge them to do so without delay.

Back to the subject at hand, RPM provides the same amount of capacity revenue to each megawatt of capacity, at a particular location, without regard to how much energy that capacity resource is likely to provide or the price at which that resource will sell energy.

To better understand what types of investment that aspect of RPM is designed to encourage, the Commission should seek answers to the following questions:

One, to the extent that RPM can encourage an increase in generation capacity, does RPM drive market participants towards increases that involve the lowest capital costs? Specifically, is the retention of older, inefficient power plants that have been scheduled for retirement, the most likely generation response to dramatically increased capacity prices under RPM?

Secondly, is the most likely generation response -- I'm sorry, the next most likely generation response, the developing of peaking plants that generate electricity at a substantially higher rate than base load plants?

Finally, the Commission should seek to understand whether the market signals sent by RPM, are being blunted by other factors, making it unlikely that the billions spent in higher capacity costs by ratepayers in PJM, can be productive in encouraging the development of new generation where it's needed most.

Specifically, this Commission should consider the effects of all of the following on the development of new generation in the most congested areas: One, the Clean Air Act permitting requirements, especially the fine particulate non-attainment areas, which could make development virtually impossible, regardless of how high capacity prices rise.

Two, planned transmission expansions that would increase the capacity in congested areas, to import electricity, raising questions about the future construction of generation assets in those congested areas. In other words, is it really a zero-sum game, and whatever development that exists, or that is undertaken in transmission expansions, undercuts the ability to build generation assets in those congested areas?

We realize that there is need for some transmission expansions and new connections. Again, those will keep the lights on, moving forward in the short term, but we wonder what the effect of that is on the construction of actual generation assets, new generation assets in the congested areas.

Third, the retention of older, inefficient plants on sites that are ideal for more efficient and expanded new generation.

Fourth, the difficulty of siting new generation in congested areas, on sites that are not already used for electric generation.

The New Jersey Board of Public Utilities has made its view of RPM clear to the Commission. We oppose the RPM settlement. We sought rehearing of the Commission's approval of the settlement.

We have taken our challenge to the appellate courts, after the Commission denied rehearing. For the same reasons, we have continued to oppose RPM. We hope the Commission will reach the same conclusions we have about RPM.

First, we expect that the first four years of RPM will produce minimal new generation in areas of PJM where the new generation is most urgently needed. Instead, the claims of substantial, quote, "net increase in capacity," unquote, essentially represent the postponement of retirement for older, inefficient units.

That postponement may temporarily help keep the power flowing. We have no complaint with that result, however, we are deeply concerned that retaining those units, locks up the sites that are best suited for development of new, efficient, and expanded generation, because they already have access to transmission, fuel, water, and because their current use of electricity generation makes them less vulnerable to local opposition.

Therefore, if RPM is having any significant effect in the most congested areas of PJM, it is to make us more reliant on plants that use scarce and expensive fuels, inefficiently, contribute to higher prices in the energy market, and cannot be relied upon for the long term.

Second, we expect that almost all capacity regimens under RPM, will have flowed in directions that have nothing at all to do with serving reliability.

Specifically, we believe that well over 90 percent of the revenues from the first four auctions, were paid to existing plants that have shown no intention of retiring. This distribution of resources confuses the market signals that the Commission had hoped RPM would send.

For this reason, we look forward to the presentations of alternatives to RPM in subsequent panels of this Conference.

At the outset, the FERC approved the RPM settlement, because they were convinced that it was better than the previously existing construct of PJM. That may very well have been the case, but we believe that alternatives being presented here, overcome some of the structural problems that we've experienced with RPM, and has shown the basis for better achieving the laudable and essential goal of PJM to bring the markets to the market capacity and resources needed for reliability of our power supplies.

I thank you for your attention and will be happy to answer any questions.

MR. KELLY: Thank you, Commissioner Butler. With us today, is Dennis Bergeron, Coordinator of Regional Affairs for the Maine Public Utilities Commission. Welcome.

MR. BERGERON: Thank you, Kevin. These comments are on behalf of the New England Conference of Public Utility Commissioners. We appreciate the opportunity to offer our observations of the current ISO New England's forward capacity market rules and our observations on the initial implementation of its first forward capacity auction.

New England state regulators have long been involved in the development and implementation of wholesale market design and rules. For example, it was negotiation between the New England Power Pool and the New England Conference of Public Utility Commissioners, that led to the development of the ISO New England in 1997.

Since then, the states, working jointly through NECPUC, sometimes independently, have frequently intervened in the Commission's proceedings dealing with market rules, or offered comments. ISO New England's forward capacity market rules were finalized only about a year ago.

The amount of effort, time, and money involved in the settlement negotiations, pleadings before this Commission, and interminable hours spent in meetings for rule development, are worth considering, if the Commission contemplates perhaps making additional changes.

Capacity products, by their very nature, generate controversy. Prior to the formation of the ISO New England, NEPOOL capability adjustment charges and NEPOOL capability adjustment penalties, served as the mechanisms to ensure the region developed adequate electrical capacity, and many of the complaints associated with those early capacity products, linger in today's capacity markets.

The controversy arises because of administrative processes used to forecast the amount of capacity resource needed, where the capacity will be needed, and at what price it will be.

No matter what process used, they guarantee complaints about the calculations and input assumptions used to generate the results. Despite their weakness, capacity markets continue to be employed, because of the potential benefits they offer, namely, price stability for load, revenue certainty for generators, and assurances of long-term system reliability to the system operators.

ISO New England's forward capacity market is an improvement, because it allows the market to determine the cost of new entry, rather than having these inputs determined administratively.

From NECPUC's perspective, ISO's first forward capacity market was successful. Much work was still required of the participants to add details for demand resources to serve as qualified capacity in the markets, even after the Commission's approval of the settlement.

A new stakeholder group was formed to help develop transition period rules and to help develop the treatment of the funds resource in the FCM. The DRWG was established, a new resource category called Other Demand Resources, which included a number of demand-response elements, including energy efficiency programs, load response to distributed generation, formation of the DRWG, brought traditional NEPOOL stakeholders together with new nontraditional sponsors of DR projects.

The new perspective and expertise benefitted the ISO in the development of its rules. Current FCM rules still require administrative determination of the amount to be purchased, but remove the need to administratively set price and provide the opportunity for demand resources to participate.

NECPUC is enthused at the level of demand response that was selected in the first forward capacity auction. The benefits that demand response can provide, given the opportunity, were foretold by modeling exercises conducted in the New England Demand-Response Initiative, a joint effort between the New England states, ISO New England, and this Commission.

Hence, the results of this auction, where DR demonstrated its value by reducing forward capacity prices, should come as no surprise. We understand the anxiety some may feel with so large a response with such a novel product, but we have long regulated energy efficiency programs in the region at the retail level, and we're comfortable they will perform as promised.

We will continue to work with the ISO to refine this measurement and its verification and measurement procedures, and with demand response providers, to develop evaluation protocols and ensure consistency across the region.

The first round results were not satisfactory to everyone in the markets. There are requests for FERC to immediately begin peeling back some of the rules to the FCM, and NECPUC believes the first auction demonstrated the forward capacity market results in just and reasonable and competitive prices for capacity.

FERC should not disturb this carefully negotiated structure, by acting on the comments filed by some, to change the rules dramatically. In fact, the market results closely resemble those models hypothesized by others, and NECPUC therefore urges the Commission to observe the results of subsequent auctions, to determine whether they, too, operate as expected.

In summary, we thank the Commission for this opportunity to offer our observations. ISO's forward capacity market rules have already gone beyond some of the things the Commission has requested in this NOPR, and before directing further changes, we request that the Commission recognize the amount of effort that's already been expended by New England's market participants, and allow additional auctions to proceed as planned.

We stand ready to work with the Commission, the ISO New England, and the market participants, to correct any significant problems, should they arise. Thank you.

MR. KELLY: Thank you, Mr. Bergeron. I'd like to start by seeing if Staff around the table, have any clarifying questions. Any questions? Would you introduce yourself?

MR. MURRELL: Ed Murrell of the OMR Staff, Deputy Director.

Mr. LaPlante, one of your comments about these excess resources at the end, when you reach the floor price, I thought I heard you say that you prorated the payments to the resources.

MR. LaPLANTE: Yes.

MR. MURRELL: What was the price that the resources actually will receive?

MR. LaPLANTE: About $4.25.

MR. MURRELL: About a 25-percent reduction below the floor price.

MR. LaPLANTE: Not percent, but 25 cents, about seven or eight percent.

MR. MURRELL: Thank you.

MR. KELLY: Other questions?

MR. O'NEILL: There seems to be a sharp contrast between the feelings of the Commissioners in the two markets. I would just ask, is there something about one market over the other, that makes you feel more comfortable?

For example, Commissioner Butler was upset about paying for old generators, the same price as new, and, as I interpret what you said, and they didn't see that as an identified problem in Maine.

I'm wondering whether or not this is more of an issue of the outcomes driving the analysis, or whether or not there's something in one market or the other, that's making these things happen?

COMMISSIONER BUTLER: I think it is probably the outcomes driving the analysis. We see what we see. We've observed this.

Maybe because of the nature of the eastern MACC location, it's not only older plants, it's plants that have no interest in decommissioning or stopping production, yet, they're getting it in any part of PJM, not as much as where the actual generation is needed. That may be just the difference of location in northeastern PJM, rather than in northeastern New England.

MR. O'NEILL: If you see that to be a problem, how would you correct it?

COMMISSIONER BUTLER: Very generally, targeting the RPM revenues, simply to those that are going to provide long-range, long-term capacity additions, and perhaps scale it. I don't know.

This is off the top of my head: With a little bit of scaling back of the amounts paid to older plants, that were scheduled to decommission and are not, so that they are on an interim basis and they do not lock up those sites that could very well be the places for new generation to be built on brownfield sites. It's hard enough to even talk about construction, to get to talk about it on a greenfield site, especially in northern New Jersey, it just is impossible.

MR. BERGERON: I'd like to agree with Commissioner Butler, that it could be the results that we've observed. The Commissions in New England participated in the settlement discussions and also participated in the rules formation.

We were content that the process was fair and open and that we were listened to. There were no real big surprises we saw coming out of the auctions. We could be in a completely different position after the next round of auction, but for right now, we'd like to sit and monitor and watch what happens and see if problems arise, but, for now, things seem to be working well.

MR. MEAD: Can I just follow up on that? Commissioner Butler, I've heard the supplier group make the point that if you introduce discriminatory pricing, whereby you're going to pay existing units less for capacity than for new capacity, that could have one of two effects:

One is that new generators, both motivated by the idea that a new generator is a new generator today, but, sometime later, they become existing generators, and if we introduce this rule that existing gets paid less than new, that the new will factor that into whether they offer or not, or if they do offer, will that increase their initial price, because they are going to have to take most of -- they're going to get a better price today than they will in the future? Can you respond to that line of argument?

COMMISSIONER BUTLER: I can't respond to the motivation of generators, obviously. Economically, it's clear that the less revenue, the less likely it is that they are going to continue to expand.

And I don't think it's simply a distinction between new and existing. It's new, exiting, and perhaps those that are scheduled to retire and are now being paid, sort of a version of RMR.

It's giving them the ability to stick around and not free up that site for alternative development.

Conversely, I've got to have a way to explain to the ratepayers that I'm responsible for, why they're paying all this extra money and they're not seeing a whole lot of bank for that buck that they're paying, at least yet.

As I said last week in Williamsburg, we're willing to be patient -- some of us are willing to be patient; the rest of them are breathing down our necks, saying, what is going on here and why are we paying all this extra money and what are we seeing for that expenditure?

And it's hard to give them an answer for that, to that question. That's why the comment.

MR. KELLY: I have a question for Mr. Ott and Mr. LaPlante. Listening to the things Mr. Bergeron liked, two stood out for me: He liked the fact that the forward capacity price was determined by the market, rather than administratively, and the forward, up to five-year contracting, as opposed to something shorter.

Would those statements characterize PJM's forward capacity market, also, or is there a difference in design between the two markets, that may not have jumped out at everyone in the audience, from this description?

MR. OTT: As far as the forward pricing aspect of, I think, the FCM versus RPM, I think they both have a one-year payment with the option to extend the payment for new entry. PJM's version of a three-year payment, there is some decline of the payment. I think in FCM, again, it's five years.

I think they both have a component that allows new entry to elect to receive a longer-term, if you will, payment guarantee. That is similar.

I think the nature of how the auction prices are determined, essentially is different in PJM. We have the floating demand curve. The price is still based on auction and still based on a supply curve that is matched with the demand curve, so there still is a, quote, "competitive auction."

It is not an open auction, a descending-clock auction; it's more of an auction that has a demand curve and clearing. That fundamental difference is there, but I don't believe it stops either or both of them, to offer a competitive auction price.

MR. LaPLANTE: I think the biggest difference is the descending clock versus the demand curve. I think it's fair to say there's a visceral reaction against the demand curve by the New England Conference, by the Utility Commissioners who strongly opposed it.

That's really what led us down the forward auction route, actually building on the work that NERA did back in 2001 and 2002.

I think we ended up there. The demand curve --

I'm sorry -- one of the issues we had to watch, was the auction setting the price. We only need a small amount of new capacity, whatever it is, 1.5 or two percent in New England, and that's somewhere between 600 and 800 megawatts a year.

We're relying on competition and new resources to meet that amount, to set the price. We have a total demand above 33,000, so a small perturbation in the supply or in the supply offered, can affect the price significantly.

So there is an ability for out-of-market capacity to affect the price in the auction significantly. I think that's an issue we have to watch carefully as we move forward.

That is, I think, one of the challenges we have on the auction side. On the demand curve side, we have a continual discussion over what the level of the demand curve should be.

As Dennis pointed out, people have these discussions every year. There would be fights about, should the load growth be higher or lower? Those with capacity to sell, wanted a higher load growth, and so you ended up in those same sorts of discussions over the capacity demand curve.

MR. KELLY: Thank you. We're about out of time. Is there any final comment that any of the panelists would like to make?

(No response.)

MR. KELLY: David, did I see your hand up?

MR. MEAD: I hope this is quick. Both the speakers from the RTOs, talked about the motivations leading to your capacity revisions, the need for locational price signals, yet when we see the results, the first couple of PJM auctions showed some price separation among zones. I believe the last one showed none.

Of course, in New England, there were none, either. What do we make of this? In the long run, is location that important, or, even if it is, if we get results that show no price separation for a significant number of auctions, to what extent can the capacity auction create the locational signals?

MR. OTT: I think that if you look at the results in RPM over the four auctions, you did see no incremental increase, for instance, in demand response, for instance, in eastern MACC. You had, again, rough numbers.

Obviously, we have tables on this stuff. I don't have them in front of me, but rough numbers for eastern MACC. DR is about 400 megawatts and the new capacity was something on the order of 700--plus megawatts.

That new capacity coming in, contributed to not having a constrained result in the most recent auction, because we had more constraint honored, if you will, in the auction I think is important, because it provides consistency between what's needed for reliability and the resulting price.

So, if it doesn't buy, that's fine, but having it modeled, is vital to make sure that the auction result is consistent with what the reliability requirements are. It's not necessarily a bad thing that we have an unconstrained situation, but it would be a bad thing, if you didn't model that in the auction, because, otherwise, the result could be counterintuitive, if you will, versus the reliability department.

MR. LaPLANTE: I would agree with Andy. Just because there was a price separation, doesn't mean the auction didn't work. I think it, in fact, means the auction did work and you were able to get the capacity you needed, without having to pay a higher price in a constrained area, at least in New England.

I will acknowledge that we have some issues in terms of how we set the reliability requirements in zones in New England, that we have to address, but I think it's encouraging that prices didn't separate and we did get the capacity we needed.

MR. KELLY: I'd like to thank all four of you. We'll call up Panel II now. As we're changing the nameplates, let me just say that the audience, we called on Andy and Dave quite a bit today. We thought it would be helpful to have them on both of the next two panels, in response to the alternative market signs.

We'll take a break after this panel, but do any of the carryover panelists feel a need to take a break now? Go for it.

(Pause.)

We're ready to go. The format for this panel, is, the first speaker will present the American Forestry proposal for up to 15 minutes; then there will be four responders for five minutes each, and then discussion.

The first presenter is Donald J. Sipe, an attorney with Preti, Flaherty, Beliveau & Pachios, on behalf of the American Forestry & Paper Association. You chose not to have a PowerPoint. It's all yours.

MR. SIPE: Thank you. I'd like to begin by expressing the thanks of the American Forestry & Paper Association for giving us this platform to discuss the subject. We appreciate all the attention Staff has given to this and the help they have given us in developing it and thinking it through.

In particular for an organization with limited resources, I think that without this sort of an opportunity, it's probably unlikely that we would be able to further this idea and get a meaningful discussion in various forums, so we want to be sure we express our appreciation for taking the time and allowing us the opportunity, and also to say it's very encouraging to us, who have worked in these proposals that we thought were constructive, with a lot of different comments, and to find out somebody out there was listening and was interested in looking to see if we have a better solution.

For those reasons, we're very grateful to be here today.

The proposal that we're going to present, was developed in the context of a very specific problem. Each of the existing capacity markets has some form of energy and ancillary service adjustment mechanism.

They are called different names in different places, but the purpose of those adjustments, is to net out scarcity revenues from capacity payments, so when you've made a capacity payment, you are not paying twice for the missing money. I'll get into that a little bit more in a minute.

The easiest way to think of this, is as an attempt to move that adjustment to the real-time. By moving it to real time, not by taking the additional dollars out of capacity, not to increase anybody's capacity or move any total amounts around, but to create a hedge below, against volatility in the real-time market, to address market power concerns, to provide greater incentives for on-peak availability, and, also, legally, to increase opportunities for demand response and frame the issue of demand response in a way that I think obviates some of the debates and problems we've seen in designing demand-response programs in the past.

We came at this from that very specific viewpoint, looking at a particular EAS adjustment, which we thought lagged way too far and has revenues from very distant past years, imprinted every year against the capacity payments and other interests we sought to correct.

So the theory of the EAS adjustment, so people can understand what it is, we're moving into real time. Capacity payments are designed, supposedly, to replace the missing money, missing money that a generator should get in the market, if there were unconstrained pricing and we had sort of perfect competition.

There's a lot of reasons why there isn't unconstrained pricing. The prices don't rise high enough, often enough, in the energy markets, so at least it's claimed that there is some missing revenue, that brings in a peaker operating, receiving only its marginal rents; it will not recover its capacity costs.

That doesn't mean that there's no excessive revenues in the market, but that they are insufficient. That's the money where the capacity payments are mentioned.

Both the PJM EAS adjustment and New England's TER, are based on estimating historic revenues that are available in the market above the inframarginal operating costs of the unit with a specific heat rate.

Those inframarginal costs for each of those units -- I'm just going to refer to it as the "strike price" from now on -- those revenues are estimated or looked at on an historical basis, then deducted from capacity payments in the delivery year.

The FPO does not propose to change the heat rate calculations or any of the other characteristics of those markets. It isn't proposed to change the way in which capacity needs to be backed by physical assets. It's not proposed to change the availability adjustment.

All we want to do, is take that adjustment, that scarcity rent adjustment, and move it to real time. We think that has significant implications, both in perceived terms and in the market. That's all that's going on here.

From a consumers point of view, although the EAS adjustment and the TER adjustment, are presented as a hedge. They aren't a very transparent hedge.

One of the problems I think we have with capacity markets, is perceptions about the fairness of those markets and a lack of transparency. When someone is telling you you're buying a hedge, that turns out not to be actually a hedge against volatility, that is a perception problem. I'll spend a little more time on that later.

Under the FPO, the real-time adjustment supplies would no longer collect from load in real-time scarcity revenues. That would provide a hedge against real-time volatility to load.

It would not change the dollars that load pays overall, but volatility, itself, is one of the risks that consumers seek to hedge by having this capacity payment.

The mechanics of the FPO and how settlements work, are described in our filing and I don't want to spend a great deal of time on that. I want to focus more on the concept of it and why consumers believe it's important.

The lack of transparency in the current hedge, is an issue in and of itself. Consumers first pay for capacity, and they may or may not like that. Then they're also made to pay scarcity rents in the real-time energy price.

They are told they are hedging that real-time energy price through the capacity payment, but they are still facing the volatility. They see the money coming out of their pocket on the scarcity prices in the real-time markets.

They don't necessarily perceive the mechanism that pays back to them in a supposedly lower capacity. That perception, aside from the volatility, creates, I think, a perception that we're paying for something and we're not getting value.

In some sense, with the EAS and the TER, I think we are paying for something. I had an interesting aside with one of our later panelists here in the audience this morning.

Their reaction to the proposal was, well, if you don't like the energy volatility, buy a hedge. Now, in the grand entrepreneurial fashion of selling us something twice, I understand that response, but from a consumer's point of view, they thought that's what they just paid for, was a hedge, a hedge on the capacity payment against volatility in the energy market.

I recognize that it can be sold once again as a hedge against volatility, at some yet higher price, but I think that's one of the things we're actually looking for, was that actual hedge and not having to buy it in another way; pay for it once and have it.

I think efficiencies arise from moving the adjustment to real time, as well as fairness issues, and actually having ratepayers receive what they thought they paid for under the hedge.

Moving adjustments to real time, I think, reduces supply incentives to exercise market power in real-time markets. I think withholding strategies become extremely problematic when you have a portfolio that is submitted in the capacity market and have an obligation to settle in real time, if you try to withhold and don't deliver in real time.

Thee is probably a better break in a real-time mechanism with a real-time adjustment, because if you withhold, you are incurring an obligation, which, if you drive the price up, you pay back by the amount you withheld.

In real time, I think the implication is that the temptation to exercise that kind of market power, should be reduced. I also believe, for reasons that I recognize are idiosyncratic in this room and not fashionable citations, but my understanding of human psychology is that the prosect of losing money in real time, as opposed to the foregone opportunity to gain money, will spur greater on-time delivery, just because the perception of losing something that you already have, will spur people not to want to make that out-of-pocket payment back.

The thing I want to focus on last, is demand response. One of the things that the FPO will do, is, I believe, get the load out of the middle of this battle about sending scarcity pricing that many consumers cannot respond to in real time, and are perceived as unfair or too high, whether rightly or wrongly.

You are not going to be sending a wrong long-term signal to those people by adopting the FPO. They will get an accurate, full price of what their long-term assumption decisions are, but you will take them out of the equation when you are trying to raise caps to get more volatility and to do other things.

Generally, demand-response opportunities of the type we see in the market, by focusing payments in the capacity area, will do a good job of getting most of the flip-of-the-switch kind of stuff that you can get, just for avoiding costs.

I believe there is more out there, which I'll talk about in a minute, but it will do a pretty good job of getting you there.

I want to do a mind experiment that I think the FPO frames a particular issue that people have been kicking around about demand response, regarding subsidy payments and things like that.

Let's just assume that we've adopted the FPO and have been going for awhile, and assume we have a perfect retail pass-through of a perfect wholesale market design, which means if a consumer interrupts at the right time, they don't need a program. They are going to miss those scarcity payments, they're going to get their full capacity payment.

They will miss the inframarginal rents in that hour, so we have this completely set up and you have basically all the incentives right in your rate design, to avoid costs and the long-term stuff. You're not being bludgeoned by price spikes, but they can take long-term measures, energy efficiency and other things, to reduce their overall capacity, so I don't think you've cut into any of that.

But when you come to a situation where they have still the ability to help hedge real-time prices for suppliers who need a hedge, suppose a supplier comes to a demand-response supplier and says, I'm going to have an outage tomorrow; you've got 100 megawatts of load on the system, and, you know, I'd really like to bid in that 100 megawatts. I know it's not going to be there, and you should reduce it.

The consumer, for whatever reason, says, it's not worth it to me. I know I'm going to avoid my whole capacity payment. I know I'm going to avoid my commercial revenues, but money is the thing.

And the supplier says, well, look, I'm facing a thousand-dollar penalty in the real-time market, and suppose the supplier could say to this demand-response provider, you know, I'm autonomous. I want you to understand that your refusing to interrupt for, say, $20 more a megawatt, you're asking me to pay you a subsidy and I just don't think I should. I think you should just interrupt for the commodity value you're getting in order to make a sale.

You can make that argument and if the consumer says, sorry, I need the 20 bucks, you should pay the consumer the 20 bucks in addition to what they're avoiding. You're lowering the cost of the hedge, you're lowering the cost. You set aside what you're lowering, for the actual clearing price in that hour.

You've got somebody out there that's got a cheaper hedge, more resources available to hedge. I think it pretty much evaporates at this point, debates about whether paying someone more to avoid cost, is a subsidy, because I think it puts the consumer focus on what it is, what product it is, that demand-response resources can sell in that situation, and what they are selling, is the long-term benefit to the system of reducing the cost of the hedge.

And that is the demand-response product, which is a service, not a commodity. It's a service. I've had this discussion with somebody who worked there before, and I know, but I think that framing of the issue, which is allowed by the FPO, opens up greater opportunities for demand response, gets us out of some of these debates about how much in excess of your avoided costs, is subsidy, how much is not.

You can face an actual market where demand response can sell that gas, if it wants to, or not, if it doesn't want to, and it provides some political insulation from allowing prices to really start racing to some fairly high levels in the real-time market.

I really appreciate the time and attention of the Commission on this. Thank you very much.

MR. KELLY: Thank you, Mr. Sipe. Mr. Ott, how does that work in PJM?

(Laughter.)

MR. OTT: Okay, well, the financial performance obligation, if I can discuss that first and put it into context, the PJM capacity product, if you will, is essentially a physical call, if you will, on energy during times of system emergency.

In other words, the load, when they are buying a unit of capacity, what they are getting, is the ability to be served, not at a guaranteed price, just to be served, to get physical energy during times of a system shortage.

So they're not guaranteeing a certain price or anything; they're guaranteed to be on the system and not rotating blackouts or whatever. Under the FPO, essentially he's changing the definition of what the capacity product itself is.

It's actually becoming an energy option, which says, now, when you buy the capacity product on a forward basis now, not only are you getting my expectation, of course, although I think, in conversations with Don, the FPO does have an expectation of physical performance, so even though it's called financial performance obligation, I'm going to assume for the purpose of my comments, that it still has the physical requirement to deliver. It's not just financial; it's not just like an LD contract; it actually has a physical requirement.

If it didn't have the physical component, by the way, I don't believe it would have resolved the reliability issue.

So, the FPO then creates an energy option that says not only are you getting the physical performance, but you're also getting the energy at a price. In fact, if the energy is not delivered at that price, as an expectation, whoever received the capacity payment, would replace it at whatever the liquidated damage index is, which, in that case, would be LMP.

That product, again, would obviously be workable, provided it was a physical performance requirement. It would replace a lot of the penalty structures that are in place today with RPM, and, I'm assuming, with FCN, to incent performance.

Obviously, the penalty would be implicit in the option. The issue becomes, since the change in the product itself, is quite fundamental, the risk that's taken on by the supplier, is dramatically changed, so the expectation of the forward price that would be required for that to occur, would be substantially higher than just the possibility of a generator, for instance, because now you have optionality and other considerations.

But, on its face, the fact that it sets an index, people know what that index is, in advance, and it becomes this other type of product. Those products are traded today, and formalizing that as part of this, could work, but there would be a substantial, I think, expectation that the price indices we're talking about here and the reference prices for capacity, would have to adapt, because of the fact that you fundamentally changed the model or the product.

With that, I'll cut my comments short.

MR. KELLY: Mr. LaPlante, you have the opportunity to respond, but don't feel obligated.

MR. LaPLANTE: I have one or two points. Could I ask Don a question, though? It would help clarify my comments.

MR. KELLY: Sure.

MR. LaPLANTE: Under the FPO, could a generator end up paying more money than they would receive as a capacity payment?

MR. SIPE: I think that's a design issue that would need to be addressed. I think you could structure it either way. I believe you're taking away from the value of the hedge, if you don't let it go negative.

To that extent, that's the down side. On the other side, obviously, if you do it ahead of time, there isn't a way to have people bid on the negative capacity, so I think the design that you currently have, sort of precludes that possibility.

Whereas, if there are advantages in having a negative adjustment, I think that this would facilitate that. Whether that's a good thing or a bad thing, I think it is what we're here to make comments about.

MR. LaPLANTE: In that case, what I think we have, is very close to what Don's talking about as an FPO. Our peak energy rent deduction is calculated on a rolling 12-month average.

It's based on the actual peak energy rents for a given month. The only reason that we went to the rolling 12-month average, is that capacity payments aren't allowed to go negative.

We didn't want to be in a position of charging generators for capacity in one month, and then rebating that money to them in the next month and dealing with that whole settlement case. That's the only reason we didn't do all the accounting within a month.

So I think the peak energy rent deduction we have, has a lot of -- pretty much all of -- the properties at the FPO that Don is talking about, has.

I think the issue of whether capacity payments should go negative or not, is an important issue. If it allowed to go negative, then I think the incentives are stronger and it may encourage longer-term contracting, because it does increase the risk to generators on the capacity side, and it gives a complete hedge.

The hedge now is limited to the capacity revenues.

MR. KELLY: Thank you. The next speaker is Dr. Jonathan A. Lesser, a partner with Bates White, on behalf of the Electric Power Supply Association. What do the generators think of this?

MR. LESSER: Thank you very much for allowing me to speak today. I was actually a witness in the Devon Power case, where a lot of these issues were first brought up.

I have had some interesting discussions with Dave in the past.

In evaluating the costs and benefits of Mr. Sipe's proposal, I think it helps to step back and ask some basic questions: First, what is the purpose of having a capacity market; and, second, what problems with the current market design will the proposal resolve?

As the Commission explained in its Devon Power Orders, capacity markets are designed to ensure resource adequacy and security. As I discussed in an article I wrote in the Public Utilities Fortnightly several years ago, reliability is what call a public good.

Like all public good, market participants won't supply relief from volatility on their own, because each will have an incentive to free-ride on others. Having a separate, well-defined capacity market was the Commission's answer to this problem.

As a result, the capacity market designs developed by ISO and PJM, are supposed to ensure sufficient capacity, both from supply and demand-response resources, to ensure the system meets established reliability standards.

If that's the answer to the first question, let's examine the second one: What problems will the FPO proposal solve? Is the problem that market incentives for new capacity investment, are not working?

I would argue, no, that, in fact, lots of new capacity is being built. In PJM, for example, new generating capacity has been proposed by Competitive Power Ventures. It sits under a 600 combined-cycle plant in

Maryland; Constellation Energy, a new nuclear facility at Calvert Cliffs; Exelon, 600 megawatt combined-cycle unit in Pennsylvania, and more.

In ISO New England, at the end of March 2008, there were just under 1700 megawatts of demand-response resources available, so the problem does not appear to me to be one of not providing sufficient incentive for new capacity investment.

In other words, it looks like the market designs are doing what they are supposed to do, although, as Mr. Ott pointed out earlier, it's still in the early stages.

Perhaps the problem is that capacity investments are not taking place in areas where they are most valuable, in other word, load. That doesn't seem to be the case, either.

A lot of the new capacity investment that's planned in demand response, is targeted directly at constrained areas, so it's not the problem of too little capacity or too little in the right places. The Forest Products Association proposal appears to define the problem as one of paying too much money for that new capacity.

There are clearly folks who believe that somehow under the regulated system capacity was somehow free. Obviously, people knew that capacity costs too much now. However, capacity never was free. It was just that it wasn't priced separately; nevertheless, it's reasonable to ask whether the FPA proposal would provide incentives for new capacity investment at a lower cost. If so, it would be a better approach achieving the same objective of providing system reliability, resource adequacy and security at a lower cost. If you're an economist like me, that's a good thing. Unfortunately, the proposal will not do that as I explained in more detail in the paper I filed with the Commission.

Let me touch briefly on a few of the problems. First, the proposal will impose asymmetric risks on generators a heads I win/tails you lose approach. In fact, under the proposal, generators face the largest downside risk in higher cost constrained areas exactly where you want to locate new capacity. It's difficult to square a heads I win/tails you lose approach with a just and reasonable standard.

Second, the proposal is designed to prevent generators from capturing scarcity reps rather like a windfall profits tax is supposed to capture excess profits. Unfortunately, by capturing scarcity reps, the proposal will take away or certainly reduce the incentive to invest in new capacity. After all, what motivates investors in a market is an expectation of earning a return commensurate with the risks they're going to take, reduce expected long-term return that you reduce investment.

Third, the proposal will, in fact, reduce the incentive for demand response rather than increase it. As Mr. Sipe has argued, the reason is that under the proposal financial risks are taken away from load and onto suppliers, so there will be less demand response despite the policy goal and encouraging more.

Finally, the proposal would greatly exacerbate the regulatory uncertainty. Developing a new market takes time, especially one in which suppliers must commit billions of dollars in new capital. Now, with evidence that existing capacity markets are, in fact, encouraging new investment despite average prices that are below the estimated costs of new entry. Changing all the rules again ought to be avoided. Sure, making minor adjustments as one goes along may be appropriate, but wholesale revisions will simply discourage new investment.

That brings me to my final question about the proposal. Suppose we were to implement the proposal, but existing generation owners decide not to participate. Under the proposal, it's certainly not mandatory that they do so.

What happens then? The only answer I can come up with short of letting reliability degrade is that we'll be back to an RMR type world of cost-based regulation precisely the world the Commission sought to move away from because of its problems. Perhaps that's, in fact, the real but unstated goal of the proposal. Thank you very much.

MR. KELLY: Thank you. Finally, we have Daniel Allegretti, Vice President and Director of Wholesale Energy Policy with Constellation Energy.

MR. ALLEGRETTI: Thank you very much for the opportunity to speak today and to respond. I want to start by thanking Don Sipe and the American Forestry and Paper Association for bringing forward a concrete proposal rather than a mere critique of the status quo, and for looking to do something that is entirely market-based and that builds upon the existing platform of the FCM and RPM market designs. I think they are to be commended for it. I think it's productive and refreshing.

There are virtues and drawbacks to this proposal. I think among the virtues are that it has a very elegant market-base solution for how you go about crediting out the energy reps from the capacity payments. It does this by changing the product from capacity to capacity bundled with an energy called option and thereby forces the bidder to internalize the value of the energy within the capacity bid.

In that sense it's very elegant and gets us away from estimates, specs, proxies, and penalties as more administrative mechanisms to achieve this. At the same time it does, however, have some drawbacks and I, for one, remain unpersuaded that it is superior to what we have today.

The first thing is that it is a higher value product when you bundle a call option for energy with that capacity and it raises the question does all of the load in the marketplace want that higher value product and are they willing to pay the higher cost of that higher value product? And as Andy mentioned, the expectation of forward price would be substantially higher for this bundled product, if you will, than for stand-alone capacity. I think there's also a question of what happens when you move more of the electricity market revenues out of the energy market and into the forward capacity market. There I think you have the potential to reduce some of the incentives for real-time responses and real-time operating efficiencies, both from the supply side and from the demand side because, in fact, load is hedged because your revenues have moved over to the capacity market.

Don is correct in that there will be incentives for demand responders to participate in the bilateral markets to help provide the energy call option to those who are looking to sell it. But at the same time I think I think there's a loss of incentives for demand response in real-time that otherwise is there under the existing energy market. I think Jonathan is also quite correct in pointing out that there may be incentives to delist, particularly in areas and zones where there are higher energy prices exactly where you want more capacity to be produced and the effect of how do we, in fact, meet our installed reserve margins, our planning reserve margins if we have a very high level of delisting. In the marketplace, the proposal is commendable in that it gives the sellers the option of selling capacity or delisting it and capturing energy reps. But the delisting issues could be problematic from a reliability standpoint.

In summary then, I think it is commendable in that it is market-based, it's innovative and it builds upon the existing platform unlike the proposal we'll hear about later from the Portland Cement Association, which I think is a much more radical rewrite of both the energy and capacity markets. I think it is commendable in the elegancy with which it internalizes the interplay between the energy and capacity markets within the capacity bids. But I do think that it suffers from several drawbacks. It creates a higher value produce that load may not want to pay for. I think the points that were made as well about the potential for regulatory uncertainty--investors are trying to make decisions and we've been through an awful lot of changes and uncertainty in capacity markets. We're still at the early stages of implementing market designs that were the subject of a great deal of negotiation. And while I think we should certainly be open to making reasonable modifications to the existing foundation that are clearly improvements, I'm not persuaded that this one is a clear improvement over the status quo. even if it's as good, I think we're better off with the certainty in marketplace and moving forward with what we have, accessing it again down the road.

Finally, I think the potential impacts to reliability and to operating efficiencies are potential, unintended consequences that if not thought through carefully could be some serious drawbacks to the proposal. With that, however, I do want to once again thank Don and the FPA for putting it forward and I want to thank the Commission for the opportunity for me to be here.

MR. KELLY: Thank you. I would also like to just begin by thanking the American Forestry and Paper Association for making the proposal. We do appreciate making proposals to the Commission that identifies solutions as well as problems in markets. There's a great deal of interest among the commissioners in this. Mr. Sipe knows he's been besieged by our staff. I think it may have grown from a 5-page to a 50-page proposal. I imagine there will be a lot of people asking very good market design questions, but I wanted to ask a question of a different sort just to begin.

My simple-minded way of thinking of this is to say that under the system's capacity markets to the degree the capacity market revenues that flow from consumers to generators are relatively small and the revenues that sell from consumers to generators in the energy market is potentially higher. Your proposal should shift that.

So two questions, one is, is that a fair characterization? And I'll tell you the second question. If that's a fair characterization, what sort of reaction have you gotten from small consumer groups, state commissioners who tell us frequently and loudly that under the existing programs the amount of revenue flow from small customers to generators in the capacity market is far too high. I'm not endorsing that, but that's what we hear and the to raise it still further, although lowering energy, but understanding that the total flow remains the same. What sort of reaction have you gotten from those sectors to just that fact, if indeed, it's a fair characterization of your proposal?

MR. SIPE: We have not had the opportunity to talk with the state commissioners. I hesitate to speak for them. Certainly the consumers that we represent believe that that shift is more beneficial. I think in the first panel we heard some reaction to the very exposure to high energy prices from inefficient units and some other things and the very question that I think a lot of consumers are asking is what are we getting for this capacity?

I think the person that was occupying this chair before me expressed some concern in that regard, although I don't know what he was saying to our proposals specifically. The idea that we're radically shifting around we were sold this sort of heat rate idea and the capacity idea on the very premise that, in fact, people would take that internal heat rate, internalize it in their capacity bids under FCP, for instance, and we would wind up with lower costs. In fact, we're hearing now that's difficult to do and it's really risky. If we make them internalized, as Dan suggests, that suddenly their risks goes up.

Well, I guess the consumer's question is are they actually internalizing that higher heat rate and are we getting the lower capacity cost from that. In which case, making them internalize it and selling off the hedge shouldn't be that different dynamically unless there's some perception of risk. Or conversely, have we been lead astray and we have a very high heat rate per unit that people are just not bothering to internalize into their bids anyway and we're getting higher capacity bids than we ought to? I don't think it can go both ways. So in that sense, I think the total dollar question is the question--is the big question and I think you'll hear people later on in panels today express that.

There is a big total dollar question about whether current design is getting the right total dollars. But from the standpoint of economic theory, I can't see why for, say, an internalization in the capacity bid is different than what they're supposedly doing right now. I fail to see the distinction.

MR. KELLY: Thank you. Questions from other staff? David?

MR. MEAD: First, Mr. Sipe, a mechanical question. If FPO were introduced into the PJM market, my understanding is that this would replace PJM's current energy and ancillary offset and the effect would be that in designing their VRR demand curve the price would not be set at net CONE, but rather at gross CONE and we would do away with the current energy and ancillary service offset. Is that correct?

MR. SIPE: That's correct.

MR. MEAD: If FPO were introduced into New England it would replace the current peak energy rent offset.

MR. SIPE: Right.

MR. MEAD: My next question then I was interested to hear Mr. LaPlante say that he saw not too much difference between the peak energy rent offset and the FPO, yet Mr. Lesser, and to a lesser extent, Mr. Allegretti, I heard you say that this was substantially different and that it introduced substantially more risks. And I didn't understand that. Perhaps you can elaborate. It's my understanding that, depending on how you set the strike price under FPO that the revenues that generators have to give up under FPO would be very similar to the revenues that they would have to give up under the peak energy rent adjustment. It's just that the peak energy rent adjustment is recent historical rolling average whereas FPO is current real-time. Can you elaborate on that point?

MR. KELLY: Just before that, I'm not sure Mr. Sipe has defined FPO. Maybe he could.

MR. MEAD: The financial performance allocation, which is my understanding, is that is the name that the American Forest and Paper Association has given to their general proposal.

MR. LESSER: In my view, the way I perceive the proposal is that by setting up this real-time adjustment essentially to the extent that the market clearing price, the but for clearing price versus the FPO, the strike price, that would be higher in areas that have low constraint and the higher that difference the greater the risk of nonperformance will be and suppliers will see that as essential an asymmetric risk. If they perform, if their capacity is available at the given time, then even though the price, the market price would be very high they'll get just the strike price based on the cost of new entry units. But of course, if they don't perform, they'll be much worse off. So to the extent that that price difference is exacerbated in constrained markets that's where I see the asymmetric risk and the risk going up.

As a result, suppliers will do one of two things. Either they'll increase their bid prices for capacity to compensate for that risk or they'll simply decide this isn't worth it and I'm going to enter into bilateral agreements. I'm going to sell my energy capacity elsewhere, et cetera.

MR. MEAD: If I understood you correctly, it's your understanding that a load pocket, the FPO revenue adjustment would be higher than the peak energy rent adjustment is today in New England because if we have OP4 in a load pocket in New England, then that is a shortage condition and that the energy rent took the hypothetical unit would have earned you then with the lag becomes a deduction on capacity price, but that peak energy rent adjustment would be lower than the FPO adjustment. Is that your point?

MR. LESSER: I'm not sure about the specifics of how things are priced in an OP4 condition, but I think in general a supplier is going to look at the FPO proposal and is going to say, you know, on the one hand we have sort of a backward-looking history of what t he peak energy rents were. So they'll have a better idea how to factor that into their bids under the FPO, though, because it's real-time. You are essentially bundling all the risks onto the supplier. You're changing the product and it becomes a higher risk product. The way I would see that is the potential loss to the supplier is greater than the adjustment under the peak energy rent.

MR. MEAD: Mr. LaPlante, do you agree with that?

MR. LaPLANTE: I actually don't follow Jonathan's logic. I think the resources bid into these markets they'll formulate their bids based on their understanding of the rules. And if a resource in a load pocket were to require significant increase in its offering to hedge those risks, I would assume they would increase their offer to reflect that. If that resulted in price separation in a load pocket, then we would have higher prices in the load pocket that appropriately reflected the risks that the generators felt that they were undertaking. So I think that the market process there would be self-correcting and fundamentally, I think these are essential performance incentives that are necessary for these markets to have credibility. When we designed SPM, we tried to make it consistent with the incentives of an energy-only market.

In an energy-only market, generators would have to perform during these hours or they would lose very, very large sums of money. If the price is $10,000 and they failed to be there for that hour, they would lose $10,000 per megawatt. I think putting these incentives in those hours makes a lot of sense and I think, if generators want market-based rates, I think it's important to have market-based performance incentives in place to allow them to earn those market-based rates.

MR. SIPE: I guess my response is I don't understand the analysis either, but I do understand that from the consumer side if, in fact, the argument is that the current EAS adjustment is not netting out scarcity rent. And that, in fact, if you moved it to real-time and netted out scarcity rent, we'd be paying less for the generation of load pocket. That's of deep concern to consumers because, in fact, we're paying too much. Those people in load pockets have a very good reason to complain. They are over-collecting, if, in fact, netting out the scarcity rent in real-time is going to drive up that cost. I understand that there is a lag. And when those monies come back out of the generator's pocket from real-time to a year later, they lose money. I don't think, though, that we can argue that a load pocket were capacity prices ought to be higher is through scarcity and where generators ought to be able to protect the money that they should collect in a scarcity market and incorporate it in their bids in those markets if the market is actually working the way I think it's designed to work. The competition, cutthroat competition and who's going to make the best estimate of what you're going to get in the energy market. If that's the way this market is working, it should be a wash with the exception of that incentive that I think is out there to make you look at that loss differently rather than just a foregone opportunity to get more capacity. I don't think the math is different. If it is, we have a much deeper problem with the capacity markets that really requires some looking at.

We've got people in load pockets that are paying too much. In fact, that would be substantially reduced by generator recovery.

MR. O'NEILL: I think we're talking about two problems. One issue on the table is how to do the energy service market adjustment. PJM has one way. New England has another. And your proposal has yet another way to do that--sort of an automatic way. The other one is that the price at which you're selling your hedge, to me, you can set that wherever you want.

Mr. Lesser seems to indicate that the generators either wouldn't participate in this market or couldn't calculate how to participate or would lose money. That's what I'm sort of not sure I understand. Why, if that were the proposal, generators would either sit it out or not be able to make the calculation. I can see that the prices would be considerably higher or could be considerably higher in the capacity market, but I'm not sure why the generators couldn't respond to that kind of market.

MR. ALLEGRETTI: I guess as I think about the challenge of pricing both products how do I price capacity in the SCM based on my exposure to a peak energy rent adjustment where if I don't perform I could have a serious financial consequence versus trying to price my exposure under a call option based on a fixed strike. In both cases, I do have to internalize the risk into my bid, but I think there is, from at least an information standpoint, more moving parts and more uncertainty for me to try and price that energy call option than there is in trying to price the risk of non-performance under the current FCM design. I'm looking not just as sort of these peak hours, but the interplay of the energy market delisted units--potential exposure there. It's a lot fuzzier looking forward trying to price that product. I think that's going to be reflected in the price. It's informational inefficiency, if you will.

MR. O'NEILL: You would bid in the auction.

MR. ALLEGRETTI: Absolutely. As I said before, it's a higher value product and we would certainly be happy to price it. But as Andy and I, I think, agree it will be priced at a higher price reflecting its greater value.

MR. LESSER: I'm also not suggesting that all generation suppliers would just say I'm not going to participate. What I'm suggesting is I believe there is a greater risk of that occurring, in which case reliability could be compromised if, for example, the price of this new combined product, for example, was not allowed--let's say there are other constraints on capacity pricing that prevented generators from essentially bidding in those four prices.

MR. O'NEILL: Is that a fear? I didn't see that in the proposal. That's a fear we're putting into this?

MR. LESSER: No, I believe it is recognition of regulatory uncertainty that rules have changed. Markets might have settlement designs that again change the rules.

MR. O'NEILL: You agree that that's not the American Forest and Paper proposal.

MR. LESSER: Absolutely.

MR. O'NEILL: You're moving us a step forward as to what would happen after somebody put that proposal on the table.

MR. LESSER: I'm suggesting that if you adopt--if you go to a new system, that that increase regulatory uncertainty. Regulatory uncertainty will tend to increase costs.

MR. O'NEILL: You could have made that argument three or four years ago about RPM, couldn't you?

MR. LESSER: I did.

(Laughter.)

MR. KELLY: We're at the end of the time for this panel. Before we break, do any of the panelists or FERC staff have any final questions or comments?

MR. SIPE: Just one final comment. We continue to hear about shifting risks to the generators. We admit that is what we're doing. We're shifting the risk. We think that's the appropriate place with the cheaper hedges. If you think in terms of what the consumer can do to hedge this risk of short-term volatility, we had to aggregate. The easiest way to aggregate is go by the utility using a cost-based rate. If you want a market solution, I don't think you're going to see market solution size hedges coming out of the consumer side unless it's to withdraw from the market, go back and find yourself a long-term supplier at some cost-based rate somewhere and to aggregate at some other level. The individual consumer, given the size of their load is not going to buy or find a neatly priced hedge. I think you've had plenty of testimony here that has told you that's consumer's experience. They can't rehedge, but they'd have to aggregate. They'd have to think about things like going back to regulate this kind of product where they guarantee a price and pay someone a fixed cost. That's the solution you want, the practical solution for consumers, but it doesn't look like a market solution. Thank you.

MR. KELLY: Mr. Allegretti, quick, final word?

MR. ALLEGRETTI: I'd add a final thought. Capacity markets are an imperfect solution to a revenue insufficient problem that results from the combination of the need to meet a planning reserve margin as well as the imposition of market-wide bid caps. I think the Commission right now is engaged in a notice of proposed rulemaking in which it's examining energy price formation. It is at least my view that we ought to focus on improving price formation in the energy markets so that we are less dependent on capacity markets as an imperfect mechanism for meeting this revenue insufficiency problem. I think the Commission's on that path and I think, while the proposals here are creative and intriguing, they move us away from that direction. And I think we do lose real-time operational efficiencies if we make that move and are better served by pursuing the reforms in the energy market. Thank you.

MR. KELLY: Thank you. We're going to take a break now and resume at 11:15 a.m.

(Recess.)

MR. KELLY: Please be seated. We'll get started. In this panel we have the second of the two alternative proposals to the existing forward capacity markets. This one is from the Portland Cement Association and others. And we have a presentation on their behalf by Paul R. Williams, President of the Liberty Energy Group. Welcome.

(Slide.)

MR. WILLIAMS: Thank you. We would like to say thank you for having us here. Our proposal is certainly a more radical approach. We want to start off by saying that we appreciate that the Commission wanted to hear more radical approaches. We definitely went through a process where people said, okay, let's step back. One of the earlier speakers said sort of stepping back what were we trying to fix under the FPO proposal? Our particular case we sort of step back a little further and we started out by saying, well, what were actually originally trying to achieve through restructuring? What have we gotten so far and then what can we learn from what we were trying to do, where we are and how we can move forward.

As a starting point, we absolutely, positively support and believe that competition is the right way to bring about the most efficient allocation of resources, the most efficient operation of those resources and we think that that's the best way to bring, on a long-term basis, the lowest cost solution to consumers. Unfortunately, our view is that we're still looking for that competition. We don't see it in the current structures. So what we did was we did sort of step back.

Contrary to what somebody said on the prior panel, I think we actually tried to put forward a concrete proposal.

(Laughter.)

MR. WILLIAMS: I couldn't pass that up.

(Laughter.)

MR. WILLIAMS: The starting point, if you look back, in Order 888, okay, the original goals are more efficient use of the existing resources, better unit availability, better maintenance, improved fuel diversity--all stuff that we support that I believe that anybody and everybody in this room--I can't imagine that anybody doesn't support that.

(Slide.)

MR. WILLIAMS: Sort of thinking back about what we were trying to achieve through restructuring, the original goals and expectations it was, essentially--and I sort of skipped. I'm not going to read verbatim the entire thing. The bottom line, the last line is lower cost power to the nation's consumers. Clearly, the original goal was about bringing lower costs to power to consumers. That's the measure of whether or not restructuring is a success.

(Slide.)

MR. WILLIAMS: So the problem is, as we've gone down that path, I think we all agree on the goals. What I think from our perspective what we think is happening is that market structures that have perfectly sound, logical, theoretical underpinnings sounds right. You run into problems because you hit smack into physical realities. Physical realities like concentration of ownership of generation, physically realities like limited transmission infrastructure. You took a system where you had all of these independent control areas and now you're trying to move power across control areas and the transmission network wasn't built to do that.

Essentially, demand for electricity is pretty much perfectly inelastic. That's different than other marketplaces. So the problem is that structure that might make sense in other industries, in other realms don't fit with electricity. So then some of those structures also create--and again, without reading along quote--there are misaligned incentives. The misaligned incentives are made worse by the current structures. So under a clearly priced mechanism, what you essentially have because of concentration of ownership there are rewards or incentives for withholding. And you know, just to quote from Frank Womack out of Stanford University, I think we have a pretty good analysis. Actually, I strongly suggest that folks take a look at this study that I quoted there. It does a very nice job of walking through the exact mechanics of profit maximizing behavior and why, essentially, withholding is incentivized and rewarded under the current structures.

(Slide.)

MR. WILLIAMS: Additionally, what we see is a market structure where marginal units--and we've heard it time and again--and the reason the forward capacity market in New England and RPM in PJM, the demand curve in New York--these structures were created because marginal units were barely surviving or were not surviving. So there was allegedly this missing money. Simultaneously, there are huge amounts of money being thrown at owners of existing resources. We believe that creates essentially a disincentive for some folks to invest and actually punishes or penalizes new entrants that actually try to invest.

Again, it's a misaligned structure. We're looking at essentially from our perspective. We don't have all the data to do this, but from where we sit and from what we can see in looking at the total charges to consumers, this is a phrase that may sort of strike a raw nerve, but looking at what used to be considered the old total revenue requirement system--and unfortunately, I'm an old rates guy, so I do sort of think about things still in certain terms. It seems to be that not only is there no missing money, but there's potentially currently there was already a huge over recovery within the system. So then it came to our thinking maybe there's just a misallocation of that money or improperly designed pricing that is essentially, like we said before, rewarding incumbent owners of generation and penalizing new entrants or competitors.

(Slide.)

MR. WILLIAMS: Essentially, the question we always like to ask is what did happen to just and reasonable? I think most folks in this room at some point in time have seen this chart, but we struggle. If I look at electricity prices to retail consumers, again remembering that that's the benchmark upon which we're going to judge whether restructuring is working or not, if I look at actual prices to consumers and I compare, in the old world, pre-restructuring what used to happen in looking at the Allegheny power system--and I'm not picking on Allegheny. They're following the rules, as they exist. But in the old world prior to restructuring their rates in three different state jurisdictions were essentially the same.

In looking at where their rates are in 2007, because in Maryland the wholesale market prices flow directly through to retail customers, whereas in Pennsylvania and West Virginia, they don't. There's a huge difference and in particular, when I look at the 2007 numbers, I really like to focus on the difference between West Virginia and Maryland because Pennsylvania there's a rate cap. There are some issues there that it's not a fair comparison. But when I look at West Virginia where Allegheny Power had just gone through a rate case, so the 2007 rates that are in this chart reflect the fully bundled cost of service in West Virginia off of the same mix of generating assets through their selling their polar service in Maryland and the polar customer in Maryland is paying twice as much because it's market-based versus cost-of-service based. It seems to us that not only was there no missing money that needed to be solved. There was already an over recovery of the revenue requirement and a more sort of systemic, a more significant redesign of the markets was what was needed.

I'm going to quickly go through some of these.

(Slide.)

MR. WILLIAMS: We don't resent people making money, but the other thing that we do see is, when we look at the difference, were the earnings for some of these companies. We look at that and say, okay, if there is an over recovery of money, where's the money going? It does seem to be showing up in their bottom line.

(Slide.)

MR. WILLIAMS: Actually, the easy part about this is these are all companies that I actually own stock in, so it's easy for me to pull these numbers from their own reports.

(Slide.)

MR. WILLIAMS: So skipping forward to the real question. What do we want in the end? What did we originally want out of restructuring? The idea was we wanted reliable electricity supplies at just and reasonable rates. That's the starting point. We want real competition between resources and between providers of the resources in the procurement process. We want economic dispatch across a broad, regional resource pool on a least cost basis, again, trying to achieve the efficiencies and the economies of scale that were in the original goals of restructuring.

We also believe that we need financiable long-term obligations because we think one of the things we've learned is that through whether it's RPM or FCM, even with a five-year option in New England, it's tough to go to a bank and finance a power project with a five-year guarantee of a certain amount of revenue. It's easier to do that with a longer-term contract.

The other thing we want is we'd like to see a better integration, particularly on a regional basis of the generation transmission and demand site forecasting, coordination, then a truly competitive procurement process via an independent entity.

(Slide.)

MR. WILLIAMS: So our market design proposal really we looked at what the RTOs were doing today. And again, without reading a long quote, we looked at them and we said, you know, the RTOs are doing a good job of essentially providing, trying to provide nondiscriminatory access to the transmission system. They're doing a good job of trying to operate a single, an Oasis system. They're conducting independent market. They conduct independent transmission planning, but the problem was when it came to operating the imbalance market for energy and ensuring resource adequacy, we don't see that the current structures are properly integrated to make sure that as they do those things it's being done so in a way that brings benefits to consumers on a least cost basis for consumers.

Essentially, if you go back a couple of slides, it seems that the benefits of the systems are flowing to the shareholders of the generating companies.

(Slide.)

MR. WILLIAMS: What we did we looked and we said, okay, the starting point of a regional procurement process would have to be load forecasting, system modeling very similar to what the RTOs do today. But essentially, taking it a step further in identify specific needs for the system, specific needs being that we need X amount of megawatts of resources, not trying to dictate a particular fuel type or particular plant type, but identifying that the system had a need and potentially had a location. Then after those needs are identified, what we looked for was a truly independent, competitive procurement process to procure those needs.

(Slide.)

MR. WILLIAMS: The thought process essentially being that out of that procurement process you would essentially create a long-term obligation that would be financiable. You would be going out far enough so that you would allow new entries to compete on an equal footing because you're far enough forward that new entrants can actually compete and somebody can offer to build something new and actually have the time to do that, and that the result of that, if they do that and they're successful in their procurement auction or process. If the resulting contracts or long-term obligation would be financiable in giving that to the supply side, what essentially we looked at was, and it's not hugely different from the FPO proposal, other than what we looked at was we then said, okay, the return is essentially a call option. The premium is the capacity payment. In return, the energy comes with a strike price. The strike price, instead of being a flat, across-the-system strike price the strike price would be a unit-specific strike price. The reason being that the revenue requirement, the sort of return of capital component is assured through the call option premium, through the capacity payments.

(Slide.)

MR. WILLIAMS: Those competitive procurement processes, the objective function that would be to procure a pool of resources that would come up with, develop a least cost plan to supply the expected load based on the system planning parameters and the load forecast of the RTO.

(Slide.)

MR. WILLIAMS: And lastly, this is what a bottom line is. The generators that are receiving the capacity payment would have essentially an uncapped capacity offer with a unit-specific energy strike price. The RTO develops their least cost solution to that series of offers through a competitive process, enters into a long-term obligation with that capacity owner. Then the capacity owner gets paid his capacity number. He delivers energy. He gets paid his energy strike price and those things would obviously have to be indexed for fuel costs and all. The consumers would end up paying a sort of blended average of the units that are serving on both the capacity and energy side. They would see price signals that are based on the capacity and the actual cost of operating the units, but they wouldn't necessarily be potentially, significantly over-funding the overall system. That's really the crux of the proposal.

MR. KELLY: Thank you very much. Let's start by getting reactions, if you'd care to offer them, from the two existing RTOs. Mr. LaPlante, would you care to go first this time?

MR. LaPLANTE: Yes, I guess as I read through the proposal it seemed that the product definitions were confused. I didn't know what was capacity and what was energy and the relationship between the two. And because of the confusion in the product definition, I didn't understand exactly what the objective function or the cost minimization problem would be. Are we minimizing a capacity and energy costs over a 20-year period and selecting the resources that would do that? Or are we buying five resources a year for some energy chunk, plus capacity chunk, then doing that for 10 years and giving everybody a long-term contract?

So I didn't understand enough details of it to really be able to think through whether it would work. I think paying-as-bid in the energy market, though, might make it difficult to operate the energy market.

MR. KELLY: After we've heard from Mr. Ott and Mr. Shanker, we'll give Mr. Williams a chance to clarify that. But let's hear from Mr. Ott.

MR. OTT: I'll confine my comments to the proposal to keep my comments down to five minutes. As I read through the proposal, I think there are, again, similar to Dave, maybe misunderstanding. It may be just some conflicting information, but one of the problematic things I see in the proposal was something we'd actually gone through in the PJM, RPM design and I'm sure in the New England design this was discussed--this concept of on the first auction actually procuring something less than the full requirement. What would actually seem one of the substantial problems we'd seen with our previous capacity markets was that it was a voluntary forward where some percentage of a load was actually procured forward. The rest could procure in a near-term basis. That raised some very fundamental institutionalized, if you will, opportunity for price suppression.

So the forward capacity price wasn't a true reflection, if you will, of what the forward requirement was to sustain what I'll call 100 percent capacity requirements. So we saw some fairly problematic pricing dynamics there.

We discussed that throughout the PJM process and did simulations. There was a very fundamental flaw to have a partial procurement or what I'll call a staged procurement. You really need to do a forward auction for the full requirements. At some point in the future, that needs to be all there, either bilaterally or in an auction. You can't have some kind of iterative process. It just doesn't seen--at least to us it didn't seem to work.

The other fundamental aspect, I think, that I want to comment on is the interrelationship between what the capacity price is and the energy call option, if you will, is actually to pay as bid-at-cost for the generators. That again, brings back memories of pay-as-bid discussions. And again, having a mandated offer requirement at cost, then you have to replace--if you don't perform, you have to replace that at whatever the market is, you know, creating some substantial or fundamental inconsistencies in what the generator would pay. So what I'm generally saying is you have to deliver your energy at cost, but if you don't perform you have to buy back at whatever market. You're basically being paid to buy back cost at market.

I don't see a workable incentive or dynamic to perform. I think the risks seem to be quite dramatic. The issue, again, is really an observation, which is lower average price or marginal price? As that dynamic shifts over time, I think this proposal would probably have to shift over time because I think it's geared toward looking at average, meaning lower and I'm not sure that's always the case. But I think, again, the issue of creating a situation where what we need on a forward basis is a guarantee of enough capacity to meet load. And you also, on the real-time basis, need a guarantee of fundamental incentives to perform. I'm not sure in aggregate it's clear. Again, it could be misunderstanding. It could be gaps. I don't see how that holds that together and actually achieves that purpose. So with that, I'll defer to others. Thank you.

MR. KELLY: Thank you. Last, we have Dr. Roy Shanker, an independent consultant representing PJM Power Providers.

DR. SHANKER: Thank you. I want to thank the Commission for inviting me today. I was asked to participate in this technical conference by the PJM Power Providers Group. It goes by P3. However, as usually, while the group is aware of my comments and my positions, they remain my own and not necessarily those of the any specific member. Also, there's a longer version of these comments from both the previous proposal and to this proposal as well as a sort of historic introduction that's available, and I believe it's posted with the meeting material.

In preparing for this session, I realized that this was the third or fourth technical conference at the Commission on this specific topic, not these two proposals, but the capacity market as a whole that I've participated in. I also realized that PJM we've been having somewhat contentious discussions on the topic of capacity markets for almost a decade. Both of these recognitions suggest that a bit more perspective might help as we continue to discuss what, hopefully, should have been well-settled issues by now. At this point, I could look back at approximately 35 years of consulting work in the energy and electric utility industry. In doing so, if you want major unifying element that seems to explain most of the issues over that time and that certainly explains most of what we're seeing in today's discussions.

Most of my career engagements revolved around simple relationships between average and marginal costs. The typical business cycles that occurred is marginal goes above and below average over time. When marginal costs were higher than average, sellers had strong incentives to build new facilities, seek contracts at what might have been perceived as premium prices and push regulatory initiatives in support of those activities. Conversely, buyers sought the protection of average rate designs, tried to discourage marginal cost pricing with ways to discriminate between old, cheaper power and new resources and looked to regulatory schemes that top the price signals being sent from the market and replace these prices with something more closely related to average costs.

The marginal costs went below average. The roles were reversed. Suddenly, load interest became supportive of marginal cost pricing. Interest became supportive of marginal cost pricing effort interest behind the fence generation netting against retail rates became popular and suppliers, as a whole, would seek alternative mechanisms for compensating that approached the average cost of rates.

What the Commission sees here today is just another variation of this historic tug of war. Hopefully, no one questions any more the need for capacity payments in markets with mandated adequacy requirements and capped energy prices. Thus, the fighting is really just positioning about the variance we see or allow in the overall package of pricing that comes about to meet this requirements. With this in mind, my intent on working for design for capacity and adequacy requirements for various markets has been to try to minimize the demands of the cycle while efficiently meeting the underlying constraint and the need for the long-term price to capture the average cost of new entry.

What we can do is adopt the perspective that the results to obtain marginal cost when they're below average and then average cost when marginal cost exceed average. In this context the discussion of the Portland Cement Association proposal, and I'll say PCA, becomes pretty transparent. Marginal prices are rising with all indications that they're significantly exceeding average cost, ignoring the recent history where capacity prices were as low as 5 cents a megawatt day in PJM. The movement of marginal pricing towards or above average triggers the same old cycle. The price movement is certainly seen as sinister and efforts by buyers are made to either price discriminate, certainly something we're seeing here. Or price and average while sellers seek to achieve and capture the higher marginal values.

To put it in context, the concern we're hearing today was sort of absent when many of the participants in the market were going bankrupt and hundreds of billions of dollars of shareholder equity was being lost. We're in a different environment today and we see this tug of war go on in a different direction. Both elements, discrimination and pushing towards average pricing, are apparent in the PCA proposal. By attempting to appear and have less than a full level of proposed resources in the proposed auction structure is the proposal sets the platform for price discrimination, mandating most offered suppliers are matched against less than full demand, resulting in an insured mandated surplus and implicit discriminatory prices as excess supply is forced to chase suppressed demand. The PCA proposal also calls for the equivalent of a return to central planning and average pricing with long-term supplies and contracts based on the ISO's long-term optimization of both energy and capacity costs and associated locking in the long-term forecasts that the ISOs made about these assumptions for these markets.

However, as I mentioned in my longer comments, the proposal incorporates inefficient structures and use of pay-as-bid as well. The obvious result of pay-as-bid pricing will be inefficient offers by suppliers in an attempt to raise their market-based capacity offers to capture any energy benefits their generation creates. But for the discriminatory aspects, the result will be a higher overall cost for consumers.

As I also pointed out, this type of pay-as-bid procurement, beyond the overarching inefficiency, also creates an impossible situation for market monitoring of supply offers. It's simply impossible to distinguish legitimate bids trying to use market-based capacity offers to capture associated energy rents from those bids reflecting attempts to economically withhold. This is just an impossible problem to solve in this environment. In other words, nothing much has changed in this underlying, fundamental issue. While expressed a bit differently, it's still driving the debate.

In a similar fashion, the Commission shouldn't be distracted by the new names, terms of initials of proposals and should stick with the principles it has repeatedly recognized with respect to market-based rates. That is, discriminatory pricing is unacceptable and that single clearing price markets, when allowed to operate properly with the appropriate mitigation, result in efficient lowest cost pricing. Thank you.

MR. KELLY: Thank you all. Before we get into questions, Mr. Williams, if you'd care to--do you want to address some of the topics that Mr. LaPlante said he didn't follow in your proposal?

MR. WILLIAMS: Yes, I generally take any opportunity to have the floor. Essentially, on the issue of sort of what timeframe the thought process was that you would solve the algorithm looking at the full 20-year planning horizon. It's basically similar to how when you do transmission planning today and you're looking at congestion and reliability issues. Basically, you do essentially a 20-year forecast of congestion cost today. So it's not similar from some of the planning, but it's actually taking it to obviously a much deeper level and using it as a basis of a competitive procurement process. So the timeframe over which you're solving is the planning horizon that's 20 years. What we would do is enter into a series of long-term obligations. So you've got sort of a transitional issue where the first couple of processes you've got, obviously, a lot of existing assets. Those existing assets have various remaining lives, so you really couldn't do 10-year contracts or 20-year contracts across the board.

What we would look at would be to do contracts on a unit-specific basis, based on the remaining book depreciation life of the assets. You've also got initially probably some market power issues where initially there might be--there would be more of a need for mitigation of existing units versus once you were in a steady, state condition you basically always only would be procuring incrementally for a small portion of the needed capacity. And I think to Andy's point I think part of our concern, part of our desire to procure for less than the full amount in the initial auctions was there was some concern about forecast error and there's also--because we're using single clearing price mechanisms in the capacity in the energy markets today, there is a perception that we're hugely overpaying for the resources today.

So the thought process I actually think, as we move forward with a different design, with a different process, there might be less concern on the part of consumers over that forecast error issue because you'd only be, essentially, in each forecast, in each procurement you're still only then working off of incremental. Essentially, each auction becomes an incremental auction that replaces any capacity that rolls off and then adds in load growth.

MR. KELLY: Mr. LaPlante.

MR. LaPLANTE: One of the basic problems with this is how I would choose which resources to pick. Would I choose a resource with--I'm used to kilowatt months. If I have to speak in those terms, $5 a kilowatt month or a $40 energy price or would I choose one at $2 a kilowatt month and the $60 megawatt hour energy price? How would I choose between all of those resources and figure out which group of resources to pick out of that in that process?

MR. WILLIAMS: You would essentially--it's similar to the old-fashioned, sort of lease-cost planning that utilities used to do. The only difference being that it's on a more regional basis and it's a competitive auction process. In other words, that same $40 for KW month and $10 per megawatt hour as an offer pair gets thrown into the stack with all the other owner-offeror pairs. You'd essentially run a model of the system over the 20-year planning horizon. Whatever produces the least cost number is your solution.

MR. LaPLANTE: That does help.

(Laughter.)

MR. LaPLANTE: I don't know how I stack things.

MR. KELLY: Before we go forward, Dick O'Neill, if I understand it, you want the ISO to forecast load, forecast load profile and to forecast all fuel prices for the next 20 years.

MR. WILLIAMS: Like they do today.

MR. O'NEILL: Okay, then make commitments based on that?

MR. WILLIAMS: That would be a significant difference, but our thought process is, again, we're trying to address flaws in the existing market structures that we're seeing sort of a series of problems. One is I kind of find it humorous that Roy talks about the problem with market monitoring because the current market structure rewards withholding. The current market structure incentivizes anti-competitive behavior and we're okay with that. But we're concerned about changing the market structure because it would make the market monitor's job more difficult. And I kind of find that hard to believe because the unit-specific prices are going to be based on the unit-specific offers and the parameters that are in that offer. So I don't see how that's any harder to police than the current structure.

DR. SHANKER: It's significantly harder and it goes to a fundamental misunderstanding of what's being proposed here in terms of pay-as-bid. Market power issues aren't very material in any capacity market. These are relatively thin markets without large surpluses and high concentration. When you go to a mitigation scheme, as PJM has, it has must-offer obligations at marginal costs. And we can argue about whether they're measuring properly. Mr. Bowring certainly is going to tell you they're doing a great job.

(Laughter.)

DR. SHANKER: Actually, I believe he is.

(Laughter.)

DR. SHANKER: But he has some objective criteria to do this. I know how to measure. We can sit in a room and argue about is the marginal to-go cost for this unit 10 or 20, but we know what we're talking about and something to look up and we can look at it. As a pay-as-bid optimization, not only are you locking in 20 years of prices, but you're sitting there in this proposal with an unmitigated capacity offer. So if I have Dave's example of the $2 energy unit, I'm going to sit there and run my own little model because I'll do that and I'll say, well, I could bid $3 for my megawatt month for my capacity, but it's unmitigated and it's market-based. And then I'd say, well, I can splice four other units, so maybe I should up it to $9 because that the amount of energy rents I can extract out of this. That's not subject to mitigation because it's a market-based capacity. I'd say, well, maybe I can get $9.50. So I'm sitting there guessing against the ISO's forecast of fuels over 20 years how much energy rent I can extract out of my unit and I'm going to get paid on the pay-as-bid basis.

Now, the guy next to me comes up with the same $9.50, but he has market power. And he says, you know what, some of my units I'll bid at $9.75 and they won't clear and I'll then economically withhold and who's going to know the difference? Not only do you have an inefficient procurement because the guy who's guessing at the $9.50, because he doesn't know what his marginal costs are, and has no incentive to bid his marginal costs. But I can't differentiate his assumptions that came up with $9.50 from the person sitting next to him that decided to economically withhold and said, aha, the right number is $9.75 because both of them can legitimately say I'm trying to capture the energy rents within my market-based capacity bid.

Who's to say when you look at a 20-year forecast of energy prices which of them did what? You just can't. There's no objective criteria. So not only is it inefficient, but it literally is virtually impossible to monitor for market manipulation.

MR. KELLY: Does staff have any questions?

MR. O'NEILL: Paul, what commitment do the customers have if the ISO gets these forecasts wrong? For example, the people you represent, if you are forecast to have, let's say, a load of 100 megawatt and you shutdown your plant, do you have an obligation to pay those capacity costs?

MR. WILLIAMS: That's one of the advantages of doing something on an RTO basis instead of trying to do it on a customer-specific basis. That actually, I think, was one of the points that Don Sipe made earlier today, to push it from a load side. The loads are so small that you actually, essentially have to aggregate those loads together and that's where, thinking through that process, we viewed the RTO level as a reasonable level where you had a big enough pool in acting as a load aggregator and a risk aggregator, the RTO load generally trends upward, not downward because, essentially, what you're asking is who bears the risk of over-procurement if certain loads go away.

If you're doing the procurement across a big enough area, that risk is significantly reduced. If you're doing that procurement over a longer term time horizon, that risk, frankly, is further mitigated because, certainly over--if you procure a new resource for the 20-year contract, certainly, over the 20-year period you've improved from--really, from our standpoint, we sort of step back--again, we're sort of stepping back to, well, what were we originally trying to do with restructuring.

Some of the problems we were trying to solve with restructuring were the lumpy investments. A utility was doing their own system planning and added a resource. That could have been, essentially, unused or unuseful or 50 percent unused and unuseful for some time period until their load grew in to need that coal resource on an RTO basis. Looking at whether it's New England, New York, PJM, California, the loads, the system loads are all big enough that you essentially need to add a new resource for two or more every year just to meet the ongoing load growth. So the concern of what happens if one particular 50-megawatt or 100-megawatt load goes away essentially goes away.

MR. O'NEILL: To summarize, you have no obligation to pay capacity costs.

MR. WILLIAMS: Right.

MR. MEAD: I think I heard everybody here who at least expressed an opinion suggest that the Portland proposal was going to lower total customer energy payments over the long run and its supporters think it's a good idea and the detractors think it's a bad idea. I'm wondering whether--apparently, not everybody.

(Laughter.)

MR. MEAD: Roy and Paul, I believe, articulated that. I'm not sure I fully understand that conclusion. If generators are allowed fully market-based front bids, I would think that if all suppliers are allowed fully market-based bids that existing units, especially since they're committing--they're going to sign a contract for 10 to 20 years are going to bid a capacity price that fully reflects their foregone energy revenues they could get over the term of the contract. Is that right? If so, does the conclusion that the Portland Cement proposal will result in lower prices, result because generators are not allowed market-based rates and are some way or another mitigated?

MR. WILLIAMS: The first piece is the current energy revenues, because it's a clearing price mechanism, are significantly higher under the current structure than under our proposal. So similar to the FTO, there's a movement of revenue streams from energy capacity, initially, because you've essentially got a lot of these existing resources. And in this case, those resources--you can't rebuild the entire system in one year or one auction. So at least, initially, we don't know exactly for the first some number of auctions there would need to be more mitigation on existing units than there would be in the future; particularly units in a particular area are absolutely critical from a reliability standpoint. Mitigation I don't think goes away initially. Over time you would be able to get to that uncapped and over time, because units are falling off, not all in one year, but on basically a staggered basis, existing units I think you would have more ability to let them offer on an uncapped basis and my expectation would be that they would offer up to from competitive industries unlike when I worked in the electricity industry.

When I worked in truly competitive industries, you would offer to a customer based on what you thought your competitors were likely to offer and what essentially the cost of new entry was. But then you entered into a contract of some term--5 years, 10 years, 15 years. And over that time period, you didn't the reprice the capital component every year. Even on an ongoing basis, as the existing contracts roll off, there would be a continuing method to consumers in the form of lower capacity and lower energy prices than what single clearing price mechanisms can produce.

At the same time, I guess Roy and I will end up disagreeing on this one forever, but it removes the incentive to withhold that the field clearing price mechanisms actually have. Roy claims to be able to sit and do the math is actually a lot easier under the current constructs than it is under something where there is actually the ability for new entrants to compete and there is new entry and real competition.

DR. SHANKER: Let's try and break David's question into a couple of pieces. The first thing is I understand that it's cost-based pay-as-bid energy. In that sense, I think your statement is right. There would be a perception that energy prices may be lower. You're exactly right and that's what I was trying to get to, but for the discriminatory aspects. I want to separate those and the underbidding procurement of pay-as-bid environment for the overall auction, including capacity will lead people to put those lost energy margins into their capacity bids. That's exactly what I was trying to say before.

As we have learned repeatedly, that kind of auction structure is not only inefficient, but typically results in higher costs unless you can get away with a price discrimination to sort of dump things to begin with and we ignored that and they do what Andy's been saying, go out there and buy everything with a locked in forecast. Do that and assume you're willing to live with a 20-year energy forecast the expectation would be that you'd increase prices. It's inherent in the pay-as-bid with one parameter open.

I'll sit there with a base-load plant. I will calculate how much I can increase my capacity bid and still stay in the lowest cost solution. I think that's what you're asking and that's exactly what the behavior will be. And it's no different than what we see in the day ahead market for a low-priced energy unit potentially raising his minimum run hours or potentially raising his startup costs to get into the solution. It's the same kind of problem. But here where pay-as-bid is for a 20-year horizon, we virtually guarantee both inefficiency, higher cost and we do, unquestionably, have the withholding issues and they're severe in this kind of environment, much more so than in the current market. We just do fundamentally disagree on that.

MR. KELLY: I gave Andy a nod a few minutes ago and then you can respond.

MR. OTT: I just wanted to respond to Dave's question. I'm one of those who have stated that this proposal, in the long run, would lower overall costs to the consumer. Similar to, I believe, where Roy is headed. I probably have two reasons why that's true. I won't repeat what Roy said. I think the inefficiency related there with the interplay. But secondly, you're setting up a central planner. People like me who would make decisions moving forward about the state of everything and the one thing we can guarantee there is the central planner would get it wrong. How long the central planner would still have their head on their shoulders is another story, but they would get it wrong.

(Laughter.)

MR. OTT: The point there is instead of having a collective group of investors making decisions and hopefully some would have the right answer and succeed. Some would have the wrong answer and fail. Hopefully, that failure wouldn't be on backs of consumers. Over time, you'd get the best of everything because you'd have diversity of opinion and hopefully, you would get the best solution. You'd have a central planner. You know that the outcome would be what the central planner decided it to be. We've experienced regulatory models in the past. One of the reasons we moved to deregulation is the idiosyncratic result we got there. So I think that also would increase prices. I'm sorry to take so long.

MR. O'NEILL: I was a little bit confused by your answer, Roy. Let me really overly simplify the problem. Suppose I was a large entity and I thought a nuclear plant was the answer to my future. I put an RFP out and let's say I actually have a site for the RFP so I could supply it and I said that I wanted to buy the energy at the variable cost of producing it in the future. If that were a competitive market, the bids I would get back would be some risk-adjusted capital costs.

DR. SHANKER: Yes, for new capacity. His concern was trying to price discriminate against existing capacity and so all those guys are going to sit there and they're not going to be doing the process you're saying. They're going to be extracting their rents back up to the same equilibrium level, which is what we want. But they're going to be guessing about it because it's going to be pay-as-bid.

MR. O'NEILL: It depends on what the cost of the new nuclear plant would be.

DR. SHANKER: Exactly.

MR. O'NEILL: If there's a new nuclear plant and they bid higher than that, they wouldn't get the capacity.

MR. WILLIAMS: But you don't have to reprice it then every year thereafter for the next 20 years, rationing it up year after year after year after year. That's part of the problem under the current structure because you're always paying the marginal price in a given year. Consumers have lost the benefit of you build an asset. It got put into rate base and it got depreciated over time. You didn't have to pay the cost of new entry for that same asset at a new cost of new entry year after year after year.

DR. SHANKER: Actually, you do. That's how the revenue requirement works out. You really do. If you work through the numbers, you'll see that the equilibrium prices, the net cost for new entry across the board is going to turn out to be just the same as the rolling revenue requirement, but for the dips above and below average and marginal exceeding and going under average prices. We go through this debate--this is probably at least the fourth or fifth time and the right answer is there. We see it. It just depends on where you are. Right now people see marginal cost high. It's awful. There is no one offering to bail out the three or four very large companies who went bankrupt and lost literally hundreds of billions of shareholders' equity on power plants that then went on the market for 10 cents on the dollar. Those all would have been in rate base in this proposal.

If the entity had made the wrong error, those would all be in rate base and we'd be sitting there saying, gee, Andy's head is on the block. And those things happen.

(Laughter.)

MR. LaPLANTE: That would be the right decision.

(Laughter.)

MR. O'NEILL: Maybe you guys should take out some insurance.

(Laughter.)

MR. KELLY: Mr. Williams, did you want to respond?

MR. WILLIAMS: I think the problem is when those companies went bankrupt consumers were paying the marginal costs from those units. That's really one of the market designs flaws that we're trying to address. Marginal units can barely survive, and yet, existing units were reaping huge windfalls so they can swoop in and buy those assets for cents on the dollar. That doesn't promote long-term a reliable supply in the industry. So having some sort of revenue stability, some revenue certainty for supplier to allow new entrants, we actually think is a good thing. And to the extent that you're concerned about a central planner making wrong decisions, at least over time, because of those contracts, those assets will essentially be depreciated, which doesn't happen under the current constructs. At least over time, if he's wrong, the impact of that is mitigated on consumer prices because it's blended in with an average. He may be wrong in one year, but we'll actually--we would be better off with those assets where the guys went bankrupt. If they were in some sort of rate base and we were getting that stuff based on the actual costs, consumers would be better off than what actually happened. What happened where their shareholders got crushed and other people's shareholders made a windfall and that's really what we're doing. Unfortunately, nobody is stepping back and looking at the overall system.

I had this conversation with somebody earlier today. If we're talking about market-based rates, but they are still wholesale electricity rates that need to be just and reasonable, and need to collect the revenue requirement for the system in order for the system to be reliable, but not over collected; and to the extent we're collecting billions of dollars more than we need to, then something is definitely wrong in the system. And from our perspective, there's something wrong in the system where you're over collecting by billions of dollars, yet marginal new entrants can't compete. Something has to change in that system.

MR. KELLY: Dick?

MR. O'NEILL: If I understand your proposal, it's backed by a lot of industrial customers, but none of the really smaller customers. Is there a reason for that?

MR. WILLIAMS: Maybe because we're industrial. It's easier to work with coalitions of industrials and coordinate with them. This is something we've really been developing that's not fully fleshed out. We're not at a point were we're ready to shop it. But sort of the opportunity to present it came up. Here we are.

MR. KELLY: We appreciate it.

MR. WILLIAMS: It's not intentional.

MR. KELLY: Dave?

MR. MEAD: You mentioned that you thought the first year of your proposal there would need to be some mitigation of existing generators' bids. I was wondering f you could talk a little bit about what principles would be used to determine what would be a reasonably competitive capacity bid, especially to what extent would consideration forego competitive energy market revenues factor into a mitigated capacity bid.

MR. WILLIAMS: Ultimately, this may not be a good answer. It may not be as specific as you're looking for. One of the things--well, there are a lot of ways you can slice and dice something like that. Our concerns are, and I sort of talked through some of the issues, it's hard. You can't take existing units that may have a shorter remaining useful life, okay, and force them into a 20-year contract. Take a nuclear unit that has eight years remaining on its current license. Well, okay, you can't really expect them to commit to 20 years because you have to allow that market participant to decide are they going to relicense that plant or not. But as we sort of think down that path or go through, okay, the duration of the obligations might have to be different. The foregone energy revenues are one concern. On the other hand, there's also the issue of capacity revenues that they are receiving or have received.

What would essentially be sort of the cost of new entry for a similar plant? Our thought process is, if you look at sort of the absolute minimum that you would have to provide those people would be, I would argue, the minimum would be essentially their revenue requirement. What is the cost of those units essentially amortized over the remaining life? Alternatively, if you look at infra-marginal revenues, you might be able to come up with some alternative mitigation scheme that gave them some portion of those revenues. I don't think just because a current market design essentially throws money at certain market participants that that then becomes a God-given right for them to reap billions of dollars in windfalls forever if there's a policy decision that says this different market design long-term produces a better results.

Just because they have infra-marginal revenues now doesn't mean they're entitled to them forever. If the regulatory regime changes or the pricing algorithms change, there's no requirement--there's nothing that says they're entitled to those revenues forever.

MR. KELLY: Let me make the final question for Mr. Williams. I was trying to think what the proposal might mean for regulation. For FERC in particular, would this be a fair extrapolation? The RTO would start to perform some functions that are akin to the functions of vertically integrated utility--the study of the long-range planning, the generation planning, and create generation procurement such that there would be an insistence by the public that regulators look at that to make sure they aren't overpaying over-forecasting, but there's a kind of need and necessity for everything. Would that be state commissions? Would that be FERC when you got to the component of looking at people bidding? There I assume it's short-run marginal costs. They'd have to adjust that as necessary and someone would have to oversee those adjustments.

What we have the checkbooks and accounts and determine the costs, good costs where true reflections of actual marginal costs where we would have something--a kind of average, not a marginal cost of service regulation. I was trying to forecast what the implications would be for regulators and whether FERC would be the regulator that would do these things that may have been done on the utility scale formerly by state commissions. If I'm all wrong, tell me. But have you thought about how regulation would project out?

MR. WILLIAMS: Yes, actually, I don't want to say--I wouldn't say it's all wrong. I think you're thinking of it with more regulation. We're thinking about more of a regional competitive procurement with oversight. And I think there is a difference between oversight and regulation to the extent -- I may go in reverse order here.

On the short run costs, your offer pair--on the offer pair the way he put it is you have X dollars per megawatt day or per KW month if you're in New England, and so many dollars per megawatt hour. The dollars per megawatt hour is really based on essentially a turbine curve and fuel price since the RTO who is doing the offer evaluations and essentially solving the algorithm to develop the least-cost plan got their price forecast that is developed through a stakeholder process, we would argue that the state commission role is mostly in the stakeholder process. The states would be able to impose or suggest to offer and to impose--in other words, if a particular state says we want X percent renewables, that becomes part of the RTO's algorithm they have to solve for because that's been imposed by a state.

If the state says we want to essentially opt out and we want to--you know, things that states decide to do that would have to be overly within the algorithm, but the RTO solves for. But the sort of higher-level oversight I do believe to be essentially an RTO function. That's more of a folk oversight responsibility to ensure the anti-mitigation schemes, particularly in the short-term, whatever the mitigation scheme is for existing units, that would be really be FERC jurisdictional to the extent that those offer curves--to sort of ensure compliance with the offer curves and I don think you really have to get into auditing books because it's really just applying a actual fuel number to an offer curve. That pretty much is done.

I would say, programmatically, that's a pretty straightforward computer program to check. Basically, it's the way a lot of market-monitoring screens are done in the RTOs today. It's oversight, but I don't like to characterize it as regulation. Our thought process is that the procurement process is actually competitive and more competitive than anything we see today.

MR. KELLY: Thank you. We're actually a few minutes past our closing time. Does anyone have a burning final comment?

MR. LaPLANTE: I guess I learned more about the proposal. I think characterizing this as a capacity market probably doesn't do it justice. I don't think that it's compatible with the current structure that we have for clearing price markets for energy and capacity, and represents fundamental change to the way that we're regulating and running the markets today. So I think, Kevin, your question was going along those same sorts of lines. It's a fundamental departure, I believe, from where we are.

DR. SHANKER: And I think, if you think about David's question about mitigation in front marginal rents, you weren't really hearing mitigation. You were hearing explicit price discrimination. We've been there. We've done that. We understand the problems that that create. If you want to expropriate property by explicit price discrimination, you may, indeed, be able to drop costs in the short run. I think the Commission has spoken very clearly for a long time about why that's not the right way to go in the markets. But understand that's what you're hearing in this discussion. And if you take away that ability to discriminate, you're going to get a long-term lock in of costs that are not well differentiated from what we would expect any other way and you're going to do it inefficiently.

MR. KELLY: I want to thank all the panelists very much for taking this time to come and educate us. I learned a lot. We're going to break now. We'll resume at 1:15 p.m.

(Lunch recess.)

A F T E R N O O N   S E S S I O N

(1:15 p.m.)

MR. KELLY: Welcome back everybody. The three panels this morning were trying to explain how the two existing new approaches to market might work with some discussion. The entire afternoon is devoted more to opinions on how the two existing markets are working and how new proposals might work or whether there are some additional tweaks that can improve things. We have invited two unusually large panels of nine people each because we really wanted a great diversity of opinion on this very important subject.

As a result of that, though, it's going to be particularly important for each of the speakers to keep to the five-minute limit. I have a little clock down here to guide you. Obviously, it will be 45 minutes just for the speeches with a 5-minute limit each. That way we'll have a lot of time after--a full hour for each panel to engage in back and forth discussion.

For this particular panel, though, we'll have seven speakers. Andy Ott and David LaPlante have said their piece this morning, so they don't need to make presentations this afternoon. But they'll be available to engage in the dialogue. With that, let's begin with the Honorable Paul Centolella, Commissioner from the Public Utility Commission of Ohio. Paul, it's all yours.

COMMISSIONER CENTOLELLA: Thank you for this opportunity to comment on the current capacity markets designs and alternative approaches to long-term resource adequacy. My comments today will address current approaches in transitioning those approaches to marketing design in which demand participation and market-based forward purchases can increasingly replace capacity requirements.

Turning first to current capacity markets, based on the assumption of inelastic demand capacity markets were a response to the so-called missing money problem which current ancillary and service prices did not meet the levels needed to support investments. That loses sight of the fact that most consumers still do not see time differentiate prices. If demand becomes priced elastic, flattening load shifts, committing price spikes and moderating of price volatility and related investment and the capacity payments required to achieve any given level of resource adequacy will decline.

RTO capacity markets are regulatory incentive mechanisms. While the determination of capacity requirements has become more complex, the product, minimum quantities, the timing of LSE is set by RTO tariffs. As a result, we should be asking fundamental questions about these mechanisms. Do year-by-year auction payments create the price expectations comparable to those in a competitive market in which demand and supply respond dynamically to price? Given the sensitivity of capacity market prices to resource requirements and uncertainty regarding future RTO administration of these incentives, do capacity markets enhance or impede long-term contracting needed to finance new generation? Do capacity markets distort resources choices, increasing investment and low first-cost alternatives, such as combustion turbines over a more diverse resource portfolio?

Given the wide range of cost and between customer classes, whether the consequences of planning, based on a single uniform resource adequacy requirement, what are the impacts on demand response, unit availability and congestion, and the resulting costs and reliability implications of shortage pricing in energy and ancillary services markets these questions should give us pause about long-term reliance on capacity markets as the means to ensure resource adequacy.

I believe this Commission should facilitate a transition toward market-based solutions where states and utilities enable consumer demand response and provide for consumer choice regarding forward resource and contract positions consistent with maintaining operational reliability of the power grid. Last Thursday, our governor signed new electricity legislation in Ohio; among other things it encourages advanced metering and time-differentiated pricing. Ohio utilities have proposed installation of advanced metering to as many as 150,000 consumers this year. Several of our companies indicated that they propose to deploy such meters to all their customers no later than 2015. We expect such deployments to support two part-time differentiated pricing that will integrate with the wholesale markets.

Utility applications addressing the recovery of these investments are expected to come before the Ohio Commission within the next few months. We need to be confident on how utilities and consumers will be able to capture the full value of price-responsive demand. Changes may be needed to move from a focus in which we have treated demand response as a program or as resale of wholesale energy back into market to a system in which we actually do security constrained economic dispatch based on a sloping demand curve reflecting the preferences of millions of individual consumers.

Turning to what this means for capacity markets, allowing demand response to bid into capacity markets has been a very positive development, but additional steps are needed. One, for purposes of determining an LSE forecast demand requirement. The LSE should be permitted to provide a supply forecast demand curve rather than a forecast. Here I want to distinguish between demand responses as a resource and price response demand, which is not necessarily subject to dispatch by the transmission provider. It still should be taken into account in setting the LSE's forecast requirements.

Second, demand, which can be interrupted in a generation emergency, should not be included in an LSE's forecast requirement and the LSE should not be required to carry planning reserves with respect to these loads. Finally, demand bids should be allowed to set prices under shortage pricing provisions in the RTO's tariffs.

In closing, I want to comment that we as federal and state regulators need to consider that future competition will not be limited to generation on generation competition. Meaningful competition will increasingly be between providers of central station generation on the one hand and demand response energy efficiency, distributed generation, and storage on the other. In this emerging environment, market-based pricing of generation affiliated with distribution companies is at risk of creating perverse incentives that may retard new forms of competition. We need to take that into consideration as we move forward. That's a brief summary of my remarks. I'd be glad to talk about that in more detail when we get to the question period.

MR. KELLY: Thank you. Next, we'll hear from Dr. William Hogan, the Raymond Plank professor of global energy policy at Harvard University.

DR. HOGAN: Thank you very much, Mr. Chairman. I emphasize I don't speak on behalf of anybody else, just my own opinions. I my five minutes I would like to make five points--A through E--that I'd be happy to elaborate later during the conversation if we have the opportunity.

I'll start at Point E, which is that these are early days in dealing with these capacity markets. In the first round of capacity markets that were put in place, it would easy to predict that they would fail. I also predicted that they would go away. It turns out I was half right. So we've gone through this long reform process and produced a new round of design, which is now just been put in place and we're starting to get some experience with. They're much better than the designs that we had before in its very early days and I just think it's too early to tell how well they're going to work. But I would be careful about blowing them up at this stage. And I think some of the proposals that we have heard, particularly the Portland Cement are radical changes that could be accommodated within that framework, so it's early days.

Point D, there's a design dilemma. The design dilemma in doing these forward capacity markets centers on the problem that basically nobody knows enough to do it really well. As a matter of fact, if we knew enough about how to do all the things that people want to do with these things, we wouldn't need markets. We wouldn't need electricity restructuring. We would only need Andy Ott and David LaPlante.

(Laughter.)

DR. HOGAN: If we think we know that much, we should just let them go do it and quit talking about the details. But I submit that designs that you seen in New England and PJM are quite different from each other in some critical factors. That's because there's no good way to do this. There are no first principles or very few that you can draw on and it's all trying to approximate something that's very hard to deal with. And I don't have quibbles with the major features of each one of them, but I do point out that they are quite different; particularly, when you start peeling away and looking at how they deal with congestion and locational differences and things like that. So there's a fine dilemma here and we shouldn't kid ourselves about how difficult the problem is.

Part C is our conflicted goals. There's a fundamental schizophrenia in all these conversations about these differences between purchasing forward hedges for energy and solving the capacity reliability problem after you've accounted for the energy purchases. I think you heard it this morning in the discussions back and forth. If you think you're solving an externality reliability problem you do it one way. If you think you're trying to buy forward energy hedges, you do it another way. We can't quite make up our mind what we're trying to do. We're trying to do it sort of both ways and it's cobbled together in ways that I think make it the design dilemma problem worse. So I think sorting that problem out and thinking about it more carefully what we're trying to accomplish would be helpful as people are thinking about modifications I might have some suggestions about that. That's the conflicted goals problem.

B is the BGS auction, a little bit of a reach, but one of the missing problems in these markets--as has been mentioned by several--is the long-term contracting in order to support investment. If you want regulators to get involved in that process and step in front of the customer and do long-term contracting on their behalf--not all of the customers, but a subset of them--then I think that the design in New Jersey is the best way to do it. It's a very nice compromise of several different things and so the basic generation service auction is a tremendous tool people should be thinking of clearly about how to integrate it with this resource adequacy problem.

It is not something under the control of FERC, but there are many things that FERC can do that make that easier for the states to do it and give them more incentive to do it, and get some cooperation. So that's Point B.

The final point, and the first one and the most important one, I've decided to call the Allegretti principle.

(Laughter.)

DR. HOGAN: As you heard this morning, the biggest problem with these forward capacity markets and reliability pricing models and long-term capacity markets is that they're distracting us from dealing with the elephant in the room. The elephant in the room is the missing money, the inadequate scarcity pricing, the failure to get the energy market implementation consistent with all of the theory. That's the problem to fix. FERC is not working hard enough, not fast enough, not doing enough, not doing enough, do it now. It's much more important than everything else that we're talking about, and quit using these conversations to distract us from actually dealing with that.

If we had an operating reserve demand curve, which I talked about before in every one of these markets, following a design like in New York and New England--except their price is too low--and we implemented that we would have better incentives for the demand side participation. We would have better incentives for operating performance and we would have a much more transparent way to deal with the problems associated with market power. It affects almost every decision that forecasters make. It comes up all over the place in various ways and I think that's the thing to focus on, the Allegretti Principle, focus on scarcity pricing and the real-time market going forward. Get that as good as we can get it because that will make all the problems in capacity markets much less important and much less significant because more of the money will be going to the energy market. Less of it will be going through these capacity markets, which are too hard to do really well. Thank you.

MR. KELLY: Thank you. Next is John Boudreau, Director Business and Regulatory Strategy at the Massachusetts Municipal Wholesale Electric Company.

MR. BOUDREAU: Thank you for the opportunity to provide my views on the forward capacity markets. Before getting into the details, let me begin with just a little description about what MMWEC is. We're a joint action agency. We act on behalf of 21 municipally owned electric system members. We procure and develop all power supply and demand side resources for these systems. We acquire capacity energy and ancillary services through the markets that are administered by ISO New England. We also own and operate a 520-megawatt Stony Brook energy center. We're in the process of permitting an additional 280-megawatts natural gas and oil-fired plant at the same site.

The load-serving entities that we represent have one overriding business goal. That is to receive reliable service at the lowest possible cost so they can pass that on to their consumers. I have three points I'd like to make concerning the capacity markets. In New England is the forward capacity market. The first point is that the forward capacity market is still an experiment.

As the Commission knows, the SCM design was created through a settlement negotiation. We think it will likely be a few years and more than one auction cycle before you can determine how successful the experiment really is. In the meantime, as you heard this morning, New England has completed the first forward capacity auction. It was successful in that it procured the requisite number of megawatts, okay, including substantial new demand response resources.

A number of the MMWEC systems didn't participate directly in the auction because we do utilize the self-supply option that was available in the forward capacity markets. However, that first auction didn't really put to rest, I don't think, all the questions, resources that cleared the auction have committed to be online by June 2010. We don't know whether those resources will, in fact, show up. Of course, in this case they're demand side resources. Whether they won't show up, the price that was achieved in the auction was clearly not a market price and after eight auction rounds, the price dropped to $4.50 a kilowatt month, which was the floor level. At that point, it was 200-megawatts of excess capacity in the market. So the resulting capacity price that was selected, therefore, was really the result of the settlement negotiations. It was not a market-driven price. And in fact, the auction may suggest we paid more for capacity than is necessary.

Finally, under the FCM on base-load resources, we have to make the same showings in the same timeframes in order to qualify for this process that we have in the forward capacity market. In some ways, we're not reflecting the differences in the lead times for these. Lead times for manufacturing commitments associated with new base-load facilities now are stretching out beyond the three-year time period that's involved in the SCM auction cycle. The qualification process may need to add some flexibility to deal and to accommodate these timing differences. When the markets started, we could probably do it by a three-year lead time, but we'd have more difficulty doing it now.

Also, in the first auction I want to point out that there were about 2500 megawatts of new generation that was participating in that auction that dropped out immediately. So we need to look at why that happened in the first round. That was a significant amount of generation that dropped out and it may well be that they were unable to meet the timeframes imposed in the forward capacity markets.

The second point I'd like to make is that the forward capacity market is really no t intended to operate independent of the other critical market design elements. The fundamental and critical purpose of the forward capacity market is to spur the development of resources. In order to do that, we need to be sure we have adequate transmission facilities and the transmission facilities are built as required.

MMWEC, as I said, had indicated that it was going to build a new generator. And unfortunately, what happened was we tried to get the generating unit permitted and we found that there was a transmission issue in the Springfield area that was going to prevent us from participating in the market. That was a transmission issue that really was raised prior to our construction. And in fact, had been identified as far back as 2002 or '03 as something that needed to be solved to resolve the reliability problem in the Greater Springfield mass area.

I think the ISO and generators who've been incentivized by constructing new generation have to have their feet held to the fire to be sure that we build these things on a timely basis. If we don't have the infrastructure, then the capacity markets aren't going to work.

Finally, I would just say our belief is that the American Forest and Paper Products Association seems to have some merit that we think we really are considering. But in general, it sounds like a good idea. But we are concerned that we need to get the forward capacity market that we have in place enough time to develop and see where it's going to go. We really haven't applied the adjustment yet, for example. And once we've had a little experience, maybe we can start making some changes. But as I said, these capacity markets are, in fact, still in the experimental stage. Thank you.

MR. KELLY: Thank you very much. Next, James F. Wilson, Principal with LECG.

MR. WILSON: Thank you. I'm grateful to the staff and the Commission for the opportunity to be up here on this panel. My comments today will primarily be based on my recent evaluation of the RPM mechanism and the result of its first four auctions summarized in my recent report entitled Raising the Stakes on Capacity Entitlement, PJM's

Reliability Pricing Model, March 14, 2008--84 pages.

The views I will express are my own and I'm not speaking on behalf of LECG. I was drawn to the field of Economics in the 1970s by the way the regulation was beginning at that time and I focused my 25-year career on challenges involved in and resulting from bringing greater competition to efficiently regulated electric power and natural gas industries.

Markets are a good thing because they create incentives and allow participants to have the best information to act on those incentives to meet consumer needs. However, incentives can be a two-edged sword with regard to capacity. I think it's first worth knowing that it's really not very important from the societal welfare perspective. If the electric system planners have targeted the bid too much or a bit to little, total capacity reserves or if the actual capacity built is a bit over or a bit under the optimal amount, this is because when an electric system has approximately the optimal amount of capacity, the marginal value of additional capacity at a marginal cost are about the same. However, on the implemented capacity incentive mechanisms such as RPM, the economics are completely and administratively and artificially changed. Now, rather than consumers being fairly indifferent as to whether there's too much or too little targeting capacity or actual capacity the cost consequences are about an order of magnitude higher.

The societal welfare conclusions have not changed. The problem is that the mechanism can cause large transfers of wealth between consumers and capacity sellers. The administrative demand curves under PJM's RPM mechanism are quite steep, meaning small changes in quantity have a relatively large impact on price. In transitional auctions, the supply curves have also typically been very steep. As a result, any small shift in supply or demand has a large impact on RPM prices.

The artificial rates stakes regarding capacity supply and demand resulting from RPM means that numerous seemingly minor administrative details can now carry price tags in the tens or even hundreds of millions of dollars. My report gives a few actual examples of those and we're talking about things like the reserve margin, the parameters of the CTO and CTEL analyses and energy and ancillaries when certain transmission would come on line. It also creates strong incentives for many market participants to offer less rather than more capacity into the capacity auctions. Unfortunately, capacity holdings and PJM are fairly large and 80 percent of the capacity in the PJM/RTO are owned by end users with portfolios large enough that offering somewhat less rather than more capacity was likely to increase their revenues under the circumstances of declaring the first four auctions.

However, under RPM mitigation, you might say, the rules require offering an existing, enforced capacity at capped price issue to have that mitigation. This is training these large sellers to do the right competitive thing, but not at all. Participants acting competitively can expect to, one, increase their ratings of their units and drive the outage rates lower to be able offer more unforced capacity to reduce their avoidable costs; two, be able to bid lower; three, to invest in older plans to keep them running additional years; four, to export less capacity.

In PJM, we can expect small market participants and totally new entrants to have the incentives to do all these things. However, for the large entities owning 80 percent of capacity of PJM, because incremental capacity lowers RPM prices, they do not have these incentives. They have strong incentives to take the opposite actions. Furthermore, even within the mitigation rules that apply to existing capacity, there are various provisions that should be clear that the conclusion is mitigated equals competitive are simply wrong under any normal definition of competitive. Results of the first four transitional RPM-bsaed residual auctions held to date are consistent with the conclusion that incentives are pointing in the wrong direction for much of the market. Little new capacity appeared in these auctions and my report critiques PJM's claim of 10,000 megawatts of incremental capacity, which contains some apparent errors and some very soft numbers.

As a result of a lack of new capacity and also seller conduct, prices were much higher than market participants or PJM expected before the auctions. In the zone with the highest prices, which should have provided the strongest incentives, which also happens to be the most concentrated zone with the worst incentive problem, plant ratings declined, outage rates increased, offer prices rose sharply and very little new capacity appeared in the first and third auction and RPM prices rose sharply.

There are also some glaring instances where resources were not mitigated to affordable costs as mitigation principles are supposed to require. For instance, in Southwester MACC, the zone between the 2008 and 2009 auctions, one third of the capacity was offered at prices two or three times higher than what they had offered in prior years. Neither the PJM nor its market monitor have either acknowledged or explained the large change. I don't know what's going on, but there was no discussion of it in the reports.

My report analyzes these and other results in some detail. However, I think it's clear from these results that RPM auctions, as they were done for the first four transitional years should never have occurred and we should not expect much new capacity.

In conclusion, I agree with some of the other commenter. The Commission should stick firmly to the objective expressed in the RPM orders elsewhere that capacity should decline in importance over time and in the meanwhile I would suggest that the errors should be kept on the low side rather than the high side. There are a number of problems, negative impacts of the high capacity prices, not just on consumers. It shifts revenue recovery from the real markets--energy and ancillaries--to the administrative constructs and it drives stakeholders to battle each other over the myriad of details involved. Thank you for your attention. I'll be happy to answer any questions.

MR. KELLY: Thank you. Next, is Robert N. Loughney, an attorney with Couch White representing multiple interveners and Connecticut Industrial Energy Consumers. Mr. Loughney?

MR. LOUGHNEY: Thank you. I am here today speaking on behalf of multiple interveners of the CIEC, the Connecticut Industrial Energy Consumers, who represent both of those groups. We represent multiple interveners of the New York ISO.

Most of my experiences with the ISO and RTO rules in New York. Multiple Interveners is an association of 52 large energy users. In answer to a question earlier, there are industrial customers, large commercial, institutional and industrial customers in the group as well as in the Connecticut group. And from my experience with New York, the question arose to me why am I here? We're talking about ISO, New England and PJM. But it occurs to me maybe it's because New York is part of this whole thing with the demand curve in 2003. We have maintained the demand curve since then. It was adopted in 2003. It was a very contentious debate, the closest vote that I know of ever of an ISO management committee and it depended on the administratively determined capacity price.

We have an independent consultant who comes in and calculates the price of the theoretical true peaker. The stakeholders have some significant input on the calculation. Demand curves are developed and the demand curve process itself is highly contentious. Many assumptions are made by demands, construction costs and prices. And again, everybody has their own views, so it's kind of a tug of war. Demand curves are then presented to the NYISO board, which has adjusted the value based upon shareholder comments. The demand curve is a problem with FERC and finally, there's no review of actual cost by any regulatory body. So the process is administrative at best, but it's often very stakeholder driven. So the end result is that nobody can really feel comfortable with it. Maybe that's the beauty of it. I don't know.

(Laughter.)

MR. LOUGHNEY: Nobody fully adopts the answer. With respect to other constructs, in New York there's been some discussion of a forward capacity market, but it hasn't gotten really far. There's no time line to completion. Discussions are still in the very preliminary stages, and from the consumer standpoint we're watching with great trepidation what's going on in PJM and ISO New England.

The energy prices and energy service prices in the New York ISO are very high. As an example, the statewide average price in 2007 was $80.29 per megawatt hour. In January through March of 2008, it's more than $90 per megawatt hour. We have a situation that may be fairly typical in New York, but natural gas clears the market a great deal of the time. So the hydro owners and coal owners and the nuclear plant owners do very well in New York. As a result, we feel like there's some misapplication of the money that the consumers are paying. In terms of market reevaluation, our membership supports the efforts that are requesting that FERC reevaluated market principles. We don't feel like market energy prices are reflecting marginal costs. We share the view that our capacity markets are not spurring investment. The demand curve itself has not really lead to any long-term, new planned proposals. They seem to be driven in New York by long-term contracts that load-serving entities go out with.

In terms of our concerns, the end users and consumers that we represent are either one or two, depending on the time of year. But New York and Connecticut rank first and second for the highest rates in the continental U.S. We see the gap and the American Public Power Association just put out the gap between the restructured states such as New York and Connecticut is growing at a greater rate than the regular states have, so the disparity between the regulated states and non-regulated states is growing and it's a problem for our members who are in manufacturing and the concerns of jobs being forced out of these higher-priced states.

We do support the Portland Cement alternative market design. We listened to the discussion this morning. I think Paul Williams indicated that the market design is still in need of further vetting. I think the questions recognized that, but I think some of the things Paul presented, in particular the demonstration of the Allegheny power system rate of discrepancy from one state to the other, based strictly on the application of the market design, indicates that there are problems out there and that those problems should be addressed.

In closing, I wanted to thank the Commission staff for inviting me here. I learned a lot. Dr. Shanker is correct. This is a continuing debate between suppliers and consumers. But I think--he doesn't think the debate should continue. I think it has to be had, but there's ample evidence that consumers are paying an extraordinary amount for investments that are not being made. Under the circumstances, it's incumbent on the Commission to review alternative market design and maybe look at their own to assure that consumers are getting a fair share of the reconstruction market.

Just recently, on May 1st, Chairman Kelliher testified before the Committee on Energy and Natural Resources in the U.S. Senate that how the Commission is a consumer protection agency. Mr. Wellinghoff shared that view. He strongly supported that FERC is a consumer protection agency and Commissioner Spitzer stated that it's the first and noblest mission of utility regulation to protect the rate-paying public.

MR. KELLY: Would you take 10, 20 seconds to sum up?

MR. LOUGHNEY: My sum up is, based on these comments, it is our hope that the Commission and this process is the beginning and not the end of the process of analyzing what capacity markets and energy markets need to be changed. Thank you very much.

MR. KELLY: Thank you. Next, we hear from Peter Fuller, Director of Regulatory and Market Affairs, New England for NRG Energy.

MR. FULLER: Thank you and good afternoon. Thank you, Commissioners and staff for the opportunity to speak here today. My name is Peter Fuller, Director of Regulatory and Market Affairs for NRG in the New England region as we just heard.

I'm speaking here today on behalf of the New England Power Generators Association in my role as the chairman of that group. NEPG is the largest trade association representing competitive electric generating companies in New England. NEPG is a number of member companies representing approximately 25,000 of generating capacity throughout New England, virtually every generating technology. NEPG has three primary messages here today.

The first is the obvious capacity markets are a necessary part of competitive wholesale markets for the foreseeable future. Today, energy and ancillary services have not demonstrated an ability to deliver on average the long run costs of needed generated resources. The early markets exhibited volatility and energy price spikes and brought into practice offer caps and other controls on prices. In the process, however, the potential to recover investment costs was largely taken out of the energy markets. And as I understand, that's the well-known Allegretti Principle, Dr. Hogan.

As a result, capacity markets are a needed part of virtually ever organized market, at least until we can accept the volatility and price excursions that are necessary for energy-only markets to support the kind of long-term invests that are necessary.

Our second point is that wholesale market design can be and should be distinct from retail service requirements. Some of the conversations we heard this morning really seem to be seeking to impress retail concepts, price stability, bundled service, long-term hedges on wholesale markets. But you do not need to be so closely linked and shouldn't be. Bundling and hedging services should be provided primarily by competitive suppliers. And in any event, under commercially driven transaction and not regulatory mandates. The wholesale market is about capital deployment and allocation for product and bulk transport of energy and needs to be unbundled enough for investors to make granular forecasts and trade off in their investment decisions.

A third point I'd like to turn to the lessons we can learn from the initial results of the existing wholesale market constructs. I'm speaking here, primarily, about New England's FCM with which I'm most familiar. There is work yet to be done to achieve the objectives of this market. But there is good reason to believe we're on the right track. The drastic structural changes are not warranted. As an initial point, it would be unrealistic to imagine that a market is as completed as FCM would be perfect right out of the box.

The first auction caused significant interest in the new entry and the large increase in demand response. Clearly, we have a strong platform to build on. Recognizing that there are limitations on changing the rules and appropriately so, to preserve the value of the bargain of the settlement for all the parties. It is not too soon to draw some early lessons and to at least start the stakeholder conversation about the work that will be necessary for future auctions.

I have three lessons that we see as lessons from the early days. Lesson Number One: CONE is used for many purposes in FCM, many of which require that it actually reflect the cost of new entry. It's not clear how much information was actually revealed about the cost of new entry in the first auction.

But CONE will be lowered, based on a formula in the rules. As CONE is reduced, it will lower the thresholds for the market monitor and potentially leave the market with very little collateral for new entrants.

It is also possible that new generation will not be feasible at the auction starting price in the near future, at exactly the time when such resources will be needed.

Lesson Number Two: The first auction in New England also revealed the extent of the potential disconnect between the locational capacity requirements calculated for use in the auction, and the reliability review conducted to evaluate whether an existing resource could lead the market through de-listing.

It's fair to say that a large number of people were stunned to learn that the reliability review, FCA-1, determined the need for roughly a thousand megawatts more in the Connecticut Zone, than were indicated in the market requirement.

To work efficiently, the market needs to have a clear and definitive statement of the amount of product desired and should clear on that amount.

The ISO is aware of this, and is working on it, and the stakeholders are gearing up to talk about this very issue in the near future.

Finally, Lesson Number Three: One of the great success stories of the first FCA, also calls for the ISO and stakeholders to take on a large and challenging task sooner and with higher stakes than might have been expected.

With roughly eight percent of the resource mix in New England committed to be supplied by demand resources, in 2010 and 2011, it's crucial that the region figure out quickly, how to operate the system with such large quantity of new, highly distributed resources that create new challenges to the system operators.

In addition, sustained reliability concerns require the region to recognize that market structures are valued in supply and demand resources, comparably, and producing, in aggregate, a resource mix that can meet the daily obligations of listed capacity resources and the needs of the system operators.

Competitive wholesale markets are not yet finished, but the structures we have, show great promise as necessary components of functional wholesale markets that will deliver efficient capital allocation to support reliable and affordable electricity supplies, in keeping with the nation's economic and environmental rules.

The New England stakeholder process has shown many times that it can craft workable, efficient solutions to market design challenges. NEPG is committed to working in that stakeholder process to address needed refinements to the FCM for the Commission's future consideration. Thank you again for the opportunity to make these comments today.

MR. KELLY: Thank you. The last of the prepared presentations will be made by Raymond DePillo, Vice President of PSEG Energy Resources and Trade.

MR. DePILLO: Good afternoon. I appreciate the opportunity to appear here this afternoon to discuss the operation of capacity markets on behalf of the PSEG Companies.

You've heard a lot of good points here today, and I thought it would be helpful if I would discuss how the capacity markets have shaped some of our actions.

To a point mentioned earlier, we are one of the large companies holding a large portfolio in PJM. However, I will state that we have increased our O&M spending to improve availability of those assets.

We have increased capacity on several units as a result of RPM. We have made significant investments in our existing assets, to ensure the long-term viability.

We have reversed retirement decisions and are investing in several new generation projects, all in response to the market signals we have been given. RPM has already had a direct and sizable impact on our capital expenditures.

We recently made the decision to undertake extensive environmental upgrades for our New Jersey-based coal plants. The capital costs associated with these upgrades, are in excess of a billion dollars, but it is not likely that we would have made this level of capital commitment, if RPM had not been in place.

Although costly, this investment is less than the cost of a new, similar facility, yet current capacity prices and energy runs, do not guarantee the full recovery of this cost. It is, I believe, unfair market implementation that justifies the result of this type of investment.

RPM has also justified environmental investments for a large portion of our peaking fleet. By taking into account, more stringent emissions requirements in the future, that ensures their viability for several more years.

Further, PSEG Power has also placed new entry bids for more than 200 megawatts since the RPM auction, and has significant additional potential projects in the PJM Interconnection queue.

I'd like to talk about one of our retirement decisions. Our C-1 Station provides an example of an older unit utilizing a site that could benefit from something else, as referenced by Commissioner Butler previously.

PSEG Power notified PJM of its intention to retire the C-1 plants in 2004, because the compensation associated with the plants at the time, was not sufficient to cover either the market cost of operation or the project investments needed to maintain the reliability of the plants.

The conditions of the plants had deteriorated significantly, because there had been inadequate revenue from the market for several years, to justify additional expenditures. PJM advised us that it wished to retain the station to meet local reliability requirements, resulting in a reliability must-run tariff to the station.

The RPM revenues received by the plants, as a capacity resource, will be sufficient to cover the normal cost of operation, after expiration of the current RPM arrangement. Including the repayment of these project investments, PSEG Power has withdrawn the retirement notice for the plants, and the station has now been committed as a capacity resource through May 2011.

Without RPM, this would not have been the case, and C-1 would be retiring in the coming May. This represents a very cost-effective resource to customers. Avoided cost is well below the cost of new entry and is thus the most economic solution for this point i time.

To address the point made earlier, we are investigating new incremental investment in this site, however, the current market conditions don't justify this investment, and this does represent the best solution at this point in time.

With a functioning and stable contract, we should also expect that long-term contracting should occur. Suppliers should have greater willingness to enter into long-term contracts, once it becomes clear that capacity markets are allowed to develop and stable results are attained.

We've already witnessed that PSEG, for example, has entered into long-term contracts with a load-serving entity in New England, post the FCM results, extending out to 2017.

Although we believe the basic design of both RPM and SCM are sound, we do think certain enhancements should be considered. These enhancements will generally best be addressed through the ISO/RTO stakeholder process, which, to date, has proved adequate to make the incremental changes necessary to improve these markets.

First, as we have heard, the CONE setting mechanisms for both markets, appear to require some modification; second, we need to address the interrelationship between the transmission planning process and capacity markets.

Third, the generation interconnection queues need to become better aligned with the long-term aspects of these capacity markets, and, finally, enhancements to the energy market designs, such as scarcity pricing, must continue.

To ensure that the customer is paying the optimal asset solutions, it is critical that energy and capacity markets demonstrate the appropriate price signals, and that these markets integrate seamlessly with the transmission planning process.

This is the best way to achieve the long-term results that we seek. I thank you and I look forward to the questions.

MR. KELLY: Thank you very much. I want to turn to Staff to see if they have comments or questions. One request or caution: I once asked a nine-person panel if anyone was free to answer a question, and all nine answered at it at ten minutes' length, so if you can, direct your questions to a certain person on the panel.

MS. KRAMSKAYA: I'm Tamara Kramskaya. I had question for Dr. Hogan. You mentioned integrating past auctions with present auctions? Could you please expand on that?

DR. HOGAN: The principal step FERC should take, is to strongly encourage, nudge, require the organized markets to implement a sufficient operating reserve demand curve. The mechanics, we know how to do, except that the price levels that they set, are ten times too low to a first approximation.

That would change the scarcity pricing that would actually take place in the real-time operating markets. It would provide a much greater incentive for loads to contract, in order to get energy hedges, going forward.

Large customers would now have an incentive to do this on their own, greater than they now have. Then, if you think that there are some customers, particularly residential, who are too busy to pay attention, and some regulator has to do it on their behalf, he should do it in a way which is compatible with the market design.

The BGS auction, which is not under your control, but is under the control of the state, is a very clever design which, in the definition of the product and how it all works, which is quite competitive, the principal features I'm thinking of, are in terms of the delivery price of energy to the customer.

Some of the problem with these capacity market things and settling the prices at the generator's location, is that it doesn't interface with the transmission grid, congestion pricing, and that's a whole set of problems that we haven't talked about here, whereas, the BGS auction is in terms of the customer.

It's a full-requirements, fixed price, going forward, so it internalizes a lot of the risks and has an opt-out feature, so the customers who have the option to take advantage of demand-side load management, can go do it, so it has a lot of very nice features, and, given that you're going to have some intervention by the regulators, that's a good way to do it.

But there's no incentive or very little incentive to do it, if the price mitigation and the bid caps and everything else, and the wholesale market guarantee that we'll never see the scarcity price, then you get into the slippery slope problem that brings us to this Technical Conference.

So that's the fundamental problem to fix; everybody acknowledges that. The only difference that I'm invoking, invoking the Allegretti Principle, is that I don't think it's impossible to fix them. I think it is possible.

MR. O'NEILL: Several speakers used the term, "administratively-determined." I guess, in particular, I address the question to Mr. Wilson.

If, in fact, the demand side of the market would participate in the market, do all these administratively-determined calculations disappear? Does the capacity market disappear, and, if not, why not?

MR. WILSON: Well, yes, if you had enough demand response, enough elastic demand, you wouldn't need a capacity market. It always clear on voluntary choices by buyers and sellers.

I think it's also generally agreed that that's quite far off. The first part of your question was?

MR. O'NEILL: Can we just get rid of all administratively-determined whatever?

MR. WILSON: You still will probably have some administrative determinations, even if you have a lot of demand response, because of all the other pieces that go into this construct.

MR. LOUGNEY: The demand response, you benefit from wherever the price settles out. They participate in the capacity markets, in this special case, resources, so they have an interest in it, but a lot of them are also -- on the consumer side, they're also concerned about the capacity price itself and what that is doing.

Some consumers have the ability to offset the impact of capacity markets, by participating in it at some level.

MR. O'NEILL: Is there a reason why your members don't participate more?

MR. LOUGNEY: In what?

MR. O'NEILL: In the real-time market, for example.

MR. LOUGHNEY: Some of them are just unable to, just because of their operations.

MR. O'NEILL: I'm not sure what it means to say "not able." I can turn off the lights in my house, and I'm technically participating in the market.

MR. LOUGHNEY: If you're running a large production plant and you're in the middle of a batch operation with fuel or something, it may not be practical.

MR. O'NEILL: You're saying there's a very high value to continued consuming?

MR. LOUGHNEY: For some people, yes.

MR. O'NEILL: Is that just a general principle, I mean, that there's not enough demand to be responding?

MR. LOUGHNEY: We have a very active demand response program in New York, and, more recently, I think the tariff has been filed. I don't think it's been approved, but opening up to ancillary services, there are people who are going to be providing reserves; others are going to be providing regulation services, but it's a mixed bag.

MR. O'NEILL: My question was, if, in fact, they participate, do we need all of these capacity markets?

MR. LOUGHNEY: I would say, along with Jim, that I don't think there's enough that are able to participate, to make it go away.

MR. MEAD: I have a bit more of a detail question, directed first to Mr. Wilson, and then perhaps a response from Mr. Ott.

As I recall, in the paper that you walked through, you questioned or raised some concerns about the estimate that PJM had made, that as a result of the current RPM markets, PJM now has 10,000 or 11,000 more megawatts than it otherwise would have.

For the benefit of everybody else, could you tick off briefly, what those concerns are or questions are? Perhaps we could get a response from Mr. Ott, as well.

MR. WILSON: I should bring my report out, in order to be able to answer that question for you. I believe that number included 1300 odd megawatts of demand response. The actual total amount of demand response in the 2010 auction, was 900-something, so I don't quite see how you get 1300 incremental, when the total is 900.

Another one was that the claimed amount of production in export, did not seem to match up with the amount of export that had been claimed in the 2006 market report, compared to the current.

I couldn't get their number; I got something less. The third that I remember -- and I think there were probably a couple more -- was the claim of incremental capacity, based retirements that didn't happen.

That is not capacity that went away or not even noticed for retirement; it's just capacity that was online, is still online, and in response to an e-mail, some of the owners have suggested that, yes, maybe they would have retired it, if it would have not been for RPM or whatever, whatever that means.

If there hadn't been RPM, they don't know what their capacity would have been. There might have been some other components.

MR. MEAD: The one that I recall, was that the new capacity was capacity that was bid into the interim market, but it wasn't clear, how much of it had cleared, but whatever. Andy?

MR. OTT: Demand response, again, when you look at demand response that's put into the forward procurement of RPM, you have to consider, not only demand response that bid and cleared in the auction, but also a demand response as part of a portfolio.

When you look at all that together, the total amount of what I'll call forward demand response, was 1373 for that auction, and that's a fact. Of course, there is the other type of demand response, which is the shorter-term stuff, which amounts to around 3,000 megawatts for the upcoming year, which we didn't count, because that stuff is much less dependable, because it's shorter-term, but the stuff that's bidding forward and committed forward for a five-year resource plan, you have to include that.

That is forward demand response that we did not have before. If you look at the import/export situation again, obviously, imports and exports are going to make decisions and can make flexible decisions to stay in the PJM market or go out on a year-by-year basis.

It's not as much of a commitment as a new resource, but it does change the supply mix in PJM. It's a fact that we did classically export capacity in the years prior to RPM, and it was a rather dramatic reversal.

It is a fact now, you may say that you can't depend on that in the future, and I may agree, but it certainly was for the delivery year in question. It was a difference in supply.

I think it's hard to argue with that. Now, as far as retirements, essentially we had 1862 megawatts of official retirement requests that were submitted to us and were formally withdrawn, so those were not based on any availability; they were based on a formal retirement request that got studied by our Planning Department, and subsequently withdrawn.

There were an additional 1200 megawatts of intended retirement where they had been talking -- either talking to us or had given us less formal indications of retirement.

Those also have been withdrawn. Of course, they weren't as official. I've asked our consultant to actually do a lot more analysis on this item about retirement reversals, and we'll have more information on that in our June 30th report.

But I think, at the end of the day, the numbers we've put out, are quite conservative. We tried to take a somewhat conservative view of the impacts, to make sure we didn't overstate these effects, because, obviously, it's a very important issue, and we'll have a lot more information at the end of next week.

Then, on June 30th, like I said, based on the formal interviews by the consultant, we'll have more information.

MR. KELLY: I have a question. I'll direct this to Mr. Loughney and Commissioner Centolella, and I'll preface it with an observation. I was trying to categorize the comments in terms of the PJM and New England capacity markets.

I think you're still in that category. People who said, well, they are early and they will need to be fixed or tweaked, but that they work within the framework, and I think I counted, out of nine people, I put seven in that category -- maybe six, depending upon what Professor Hogan does.

(Laughter.)

MR. KELLY: For a more serious change, there were two, at least this is my observation, Mr. Loughney and Commissioner Centolella, but, I thought, in opposite directions.

Mr. Loughney is from New York and wasn't necessarily commenting on the New England or PJM market and may or may not be too familiar with the two proposals, alternative proposals put out this morning.

But I thought the tenor of your remarks were more in support of those points of view. You were concerned with gas setting the marginal price. There were well transfers there.

I sensed you might be more friendly to the two alternative proposals. You said you favored alternatives, but you didn't mention those two, in particular.

So the question for you, is, do you have a view on these two proposals this morning? Before you answer that, I thought Commissioner Centolella wasn't satisfied with the capacity markets, but rather than going in the direction of the two alternatives, which recover more revenues from capacity markets and less from energy, he went in just the opposite direction and recovered more -- perhaps all revenues -- from the energy markets, and perhaps would go so far as to do away with capacity markets.

But you were words were "reduced need for it," as opposed to abolish it. I would ask you for your thought on that, but I'll start with Mr. Loughney, and see if you want to help me understand your views. I want to follow my own admonition and not ask nine people to answer it.

If one of you thinks I've unfairly characterized your views as one of those three bins, please speak up also. Mr. Loughney?

MR. LOUGHNEY: You're correct; I did speak on behalf of asking the Commission to sort of take the lead in looking at these alternatives, and I thought I said we were more supportive of the Portland Cement proposals. If I didn't, I apologize, because it takes a more comprehensive look at the what the total cost is for capacity energy, trying to get to the lowest possible cost and the most efficient cost for consumers.

That's my view of it, that it may be more drastic, it may take quite a bit of time to get through all the details, but, at a conceptual level, it seems to me that it takes a more comprehensive look at what the total cost is from the bidders, and puts them in the queue that way, and that should lead to lower prices for consumers.

MR. KELLY: Commissioner?

COMMISSIONER CENTOLELLA: I would agree that I think we're moving in opposite directions. I would not be supportive of the Portland Cement proposal, for some of the reasons that were talked about this morning, in terms of centralization of planning and the potential of moving to pay-as-bid type of approaches, creating errors, and, potentially, actually having higher costs.

Just briefly, in terms of the other proposal we heard this morning, the Forest and Paper Association proposal, I think it's interesting, but I think the kind of hedges that they're talking about, are the kinds of hedges that customers ought to have choices about whether or not they make, as opposed to something that is a regulatory requirement.

So, in terms of where I was trying to take this discussion, I see us as having these capacity markets, as essentially a necessary transition mechanism, given that we do not today have significant demand response in the market.

I guess I am more optimistic about the case that demand response can plan the market, than some of my colleagues on the panel are. If you look at what has been achieved in some of the programs and pilots that are out there around the country, where there is some form of regional demand response, you see that in the residential sector.

If you begin to add in technology, which is falling in cost, the potential to get as much as 40 percent peak demand reduction on some of these programs, from residential customers, if, in fact, that is more generalizable, which is the kind of thing that we will be testing over the next couple of years in various places around the country, it suggests that demand response could play a much bigger role.

Of course, there are other technologies that may be not too far in the future, like plug-in hybrids, and they could also significantly change the demand shape, and begin to respond to price in some cases.

So, if we assume that's the case, then, going forward, we have a plan, going forward, and I do believe that there are going to be significant transitions required in this industry in terms of the increase in cost of capacity and fuel in terms of carbon regulation, in terms of the need to support additional economies, and we're going to have some significant changes in the industry.

As that goes forward, that's what we ought to be planning for, looking at how these markets evolve. As we do that and see this potential for increased price response to demand in the marketplace, we ought to, first of all, in the capacity markets, be recognizing the slope of the demand curve, as people are able to forecast that with these measures going in place, with retail rate designs changing.

As people are able to forecast that, we ought to say, well, whatever the lowest total resource requirement is around that forecast curve, that's what ought to be the remaining capacity requirement for that LSE.

And, to the extent that there are other demand resources, either because of advanced metering or because they're dispatchable by the transmission provider, they can't get off in an generation emergency, that also should come off of that forecast and we should not be establishing planning reserves with respect to either of those types of loads that are able to come off the system.

That is not to say that there may not be some of those customers that will not choose to engage in hedging behavior. With respect to some load that might come off, there may well be choices people make to engage in forward contracting on their own.

We are engaged in what I find to be a curious enterprise where we assume load doesn't want to contract forward, and, therefore, we have to impose requirements on it. If you look in the markets around the world, it tends to be the loads that want to be hedged, and the generators who seek risk from being over-hedged and the potential of having costs, if they don't perform during a high-price period.

So, I think we will see hedging as these markets go forth, but it will be hedging based upon consumer preferences and not based on an administrative requirement. That's the way I think we gradually see these capacity markets at least lessening in their impact on consumers, perhaps some day going away, but at least we see a substantial decline in their role, an increase in the role of energy and ancillary service markets, so that we accurately reflect shortage pricing and we get the right price signals on an operational and real-time basis and see less of the revenues flowing to capacity markets.

MR. KELLY: Thank you. Does anybody object to my rough assignment? Mr. Hogan?

DR. HOGAN: I'm with him.

(Laughter.)

MR. KELLY: At least two votes. That could go opposite to the direction of the two alternative proposals to recover more revenues from capacity markets and less through energy.

I'm not at all claiming that this panel is necessarily representative of all views. We're going to hear different views on the next panel.

Dave?

MR. MEAD: I had a question for Professor Hogan. With respect to your Allegretti Principle, if I recall, you said that the current operating reserve demand curves in New England and New York, are going in the right direction, but those prices aren't good enough.

I was wondering, why did you conclude that the prices aren't high enough, and how would you go about figuring out what they should be?

DR. HOGAN: The features of the New York and the New England operating demand curves are that they are integrated with the energy markets, they measure the observed amount of actual and operating reserves, and if that's low, then this creates a scarcity price in the operating reserve and that propagates through to the energy markets, as well, and changes the energy prices.

So that goes on more or less simultaneously and is integrated, but there's no underlying analytical first principles about where do the numbers come from. They're sort of engineering judgments.

And this is my speaking on behalf of myself, but if you step back and look at it -- and I've done this with some others -- the principles are pretty straightforward. The connection point is, you have to integrate to continue to meet the requirements and the expected value of what the operating reserves are going to be in just the mechanics there, but we can do that.

The critical thing is, when you really get into the position that you are shedding, you don't have enough operating reserves, so that you're shedding load involuntarily, and then the price better be the average price of the value of the lost load.

That's the only logical first principle, for establishing the connection, and what that number is, precisely, we could argue, was $10,000 a megawatt hour or 15 or 20. I don't think that's a critical issue, but it does give you an anchor as to where you should be when you really get down int the low levels.

The numbers that are embedded in these operating reserve demand curves from New York, for example, are about ten times lower than that.

So there's big gap, but that's an easily fixable problem, because you just change that number. Everything else, the mechanics are already in there, and they probably want to put in a few more steps to smooth it out a little bit, and you can use the expected value calculations.

We've laid out how to do that, in principle, so it's not an especially complicated thing. You have to map it in all these places, to actually have a -- it's not just used as operating reserves; there's a whole series of steps to go and the reserves start getting involved about interrupting loads or reducing voltage and so forth.

You have to map those into that, but I've discussed that with various system operators, and that seems to be a doable thing, not particularly hard to do.

The critical thing is here, that that would establish a price that would propagate through the energy market and everything else. Then my prediction is, you're not going to pay $10,000 a megawatt hour. All of those load response things are coming on now and saying, hey, wait a minute, I can get it for this and I can start seeing it.

The problem is, without that operating reserve demand curve, the mechanics of how these systems work, always end up with this marginal cost of the most expensive plant running, except for that one we don't count.

(Laughter.)

DR. HOGAN: And we curtail load, and that makes the price go down, so there's a whole series of just mechanical things that would be solved, if we had enough load bids.

But there are not enough load bids, because the price never gets there. They have to get something to get the chicken-and-egg problem resolved in the operating demand curve, so you'd have the value of lost load, the contingency requirement, the expected values above that, and you will produce many hours where you are a little bit short, not a few hours where you're a lot short, so you wouldn't get gigantic prices, but, in principle, you could.

But it's more likely that you'd get all this load response and the system wold more or less take care of itself and it would have the tremendous advantage then. You'd still have a capacity market argument about it, but then it would resolve some of this what I call the conflicted goals problem, because you would not be buying energy.

It would all be handled in a different way. You would just be buying this reliability requirement to make sure that you had enough capacity, so that for two hours every ten years, you don't have the lights go out and you don't have to deal with that.

Then you would be constrained to minimize the capital costs associated with doing that, so it would be the complete reversal of what we're talking about.

You wouldn't worry about recovering the energy or anything like that; you'd just want to get the least expensive bicycle generator that you could put in there, that you're only going to have to use two hours a year and wouldn't be worried about all this hedging the energy. That would be handled in a completely different way.

I think it's quite doable, and it's under FERC's jurisdiction and it would have a dramatic effect on capacity markets on investments, on transmission investments, integrating, networking energy markets. It would probably get through all sorts of things and load responses.

It would finally provide the conditions where it would be in the interest of the load to get in there. It's a great idea, do it now.

(Laughter.)

MR. KELLY: Ed?

MR. MURRELL: I had a question that I wanted to ask. Mr. Fuller, I thought I heard you say earlier, when you were describing your three lessons, that you said that you expected that new entry is going down. Could you explain more, what you meant by that?

MR. FULLER: Under the settlement agreement, we set up our forward capacity market. We came up with a mechanism that, in its theoretical basis, was intended to take the cost of new entry, and roll that into a weighted average, updating the CONE parameter, so that we would avoid some of this administratively-set issue.

We actually carefully crafted some restrictions on that. In other words, we would only reset the CONE when new entry actually entered the market.

We wouldn't reset new entry on imports. I think there are one or two other things that we said that probably isn't the right information that we want.

Unfortunately, when we settled all this, the first three years of setting CONE, are just as straight, here's the formula, the result of the auction feeds straight in, so what I'm premising my thought on, is, what we saw in the first auction, is, we started with a slight surplus.

We finished with a larger surplus, with regard to the new entry that occurred, and took us to the floor. There is, I think, valid reason to suspect that with that 2,000 megawatt surplus and the tremendous show of interest that Dave pointed out, there may very well be additional entry which could result in us clearing out the floor again, and potentially still being in surplus.

Let's see, that's the second auction. Again, the third auction potentially clearing out the floor and, at that point, the floor goes away. It's a whole new world.

One of the concerns that we've seen, is, if you follow that path, you get to where CONE, I believe -- let's see, it was $7.50, it was $6.00, and I think it goes down to a little under $5, and might even go lower in the floor price here. I'm not sure.

But we have seen bids recently in Connecticut and in the work that PJM has done on the cost of new entry. We've seen places where, today, with the high construction costs, the pure proxy peaker capacity is over $10 a kilowatt month, in our terms.

There is a question about, as we go down the road, where we get ourselves in a box, where at the opening price, the new entry that people kind of tend to think of, won't be able to participate.

There are other, obviously, factors involved there, but that's one of the thoughts and one of the reasons we would like to start that conversation.

MR. MEAD: Can I follow up on that? My understanding is that New England had some new entry that they treated themselves as exiting. Is that provision, that, is, new entry treating itself as existing, is that permitted in the next couple of New England options?

MR. FULLER: No, that was one time.

MR. MEAD: Why would you expect that must-bid, as new entry, would be seen in the auction at a price below what actual is?

MR. FULLER: One of the other features that we have, is the ability for a new entrant to seek to convince the market monitor that, in fact, a low bid is consistent with its long-run cost, if it is, in fact, whether someone can find a supply resource that is actually quite inexpensive, or demand resource that is inexpensive and can convince the market monitor.

That would be good information to know that things can be done that inexpensively, but even if you cannot convince the market monitor, those resources stay in the market and effectively become non-price-setting, but still part of the supply.

You can still enter the market. One of the things that I think is quite possible, that we know will happen, is, for instance, the capacity procurements in the state of Connecticut, will produce contracts, cost-of-service contracts where there's a unit that already has not a cost-based or cost-of-service, but a long-run contract with the state and their utilities, which will be required, I believe, under the terms of the contract, to be a cleared capacity resource.

It will be coming in as new supply, not setting price, but adding to the supply.

MR. MEAD: And this is capacity, not under the alternative capacity price rule?

MR. FULLER: Interestingly, alternative capacity price rule -- probably by Lesson 4 -- was set up as the initial trigger on the alternative capacity price rule. For that to even matter, you need new entry, must be required.

As you see on the second auction, just on the status quo, we're about 2000 megawatts long. If you take into account growth in the ICR, we may be 1500 megawatts long. So the alternative capacity price rule for all intents and purposes is a non-issue.

MR. O'NEILL: You mentioned the starting price when you got behind. It's my understanding that the starting price in a declining clock auction is somewhat arbitrary.

MR. FULLER: It is. I'm going on the premise that the settlement says what the settlement says, that it's two times CONE.

MR. LaPLANTE: It's set by rule right now.

MR. O'NEILL: The theory of the declining clock auction has virtually no importance if that's really an issue.

MR. LaPLANTE: That's certainly something I will be looking at. We don't want to start the auction at a price that's not going to result in competitive auction.

MR. KELLY: While we're on the theme of CONE, Mr. DePillo talked about -- I think defended -- the PJM system to a degree, but said it needed some improvement. One of the improvements you mentioned was that you wanted to modify the CONE-setting mechanism.

I have some thoughts about how that would go. But I was wondering if they would coincide with yours.

MR. DePILLO: The CONE-setting mechanism in PJM, as defined under their settlement really can only move in small increments. To the extent that you have, let's say, a step change in the cost of construction as was probably witnessed through the past year, the cost of new entry cannot be responsive to that. It can't increase fast enough even if you have new entry bids to justify that. I'll defer to Andy if I'm speaking anything that's incorrect here.

And then PJM is left with an alternative to bring before, let's say, the Commission, a change in CONE that may be necessary to reflect current market conditions. What we had proposed in the settlement was much more an empirical CONE where actual bids from new entry in the marketplace, in the current auction set the determination point, or cost of new entry, in the subsequent auction as opposed to small ratchets in the price-setting mechanism itself.

MR. KELLY: Thank you.

I have a few others. Anybody else?

MR. O'NEILL: No, I'm done.

MR. KELLY: I had a question for Mr. Wilson.

You said you did a study that you indicated included the possibility of large suppliers having incentives not to build, because they have a large market share -- which I took it to be kind of the way a monopolist would restrict output to get more price per unit over fewer units and get higher revenues. That only works, though, if someone with a large market share gets certain information.

I'd like to hear your thoughts on this. Am I right so far in my reasoning? How is it that we restrict that? Are there other factors that might fall within this Commission's jurisdiction that would need to be addressed?

MR. WILSON: My comment was not about that longer-term view of the incentive to build or not. My comment was about the incentive to offer relatively more or less capacity in an RPM one-year auction as mainly focused on the transition years when that supply curve was very steep.

A large entity might go ahead and be building something. But if they do, they don't actually have to offer it into the RPM auction. To decide whether or not to do that, they will take into account the impact on the price and the number of megawatts they have earning that potentially lower price.

MR. O'NEILL: What about entry that isn't owned by the new peak supplier? Are there barriers to that? That's what we're hoping works.

MR. WILSON: Commissioner Butler suggested -- and I haven't done a study of it, but -- the incumbents have, especially probably in places like northern New Jersey, have sites where they have older plants. And those are probably some of the best sites to build new capacity in, and it may be very difficult to find a green field in some of those locations. I haven't studied that, but I've certainly heard that said.

MR. O'NEILL: That is something that ought to be studied.

MR. WILSON: Yes.

MR. KELLY: Mr. Boudreau, if this is an unfair question, don't answer. But I was struck by your commentary. I know you're speaking just on behalf of your company. But your view was that the New England capacity market is still an experiment, and you're not ready to do away with it. We should wait, you said, at least a few cycles to see if it's working before we make any radical changes.

Because I've heard the opposite view from a number of people in public power, I wonder if you knew, and your public power colleagues in New England, if you were a minority among them or the majority?

(Laughter.)

MR. BOUDREAU: It's hard to say. I would say that I probably represent the largest percentage of the public power systems in New England.

I think there's a certain vested time that was spent getting these markets up and running, to try to see did they work. We're talking strictly now about the capacity market, and how the capacity market works. We have other issues, obviously, that we could address.

But, no. I do think there was a sense that these markets are there, and we want to see if they work. We were clearly very instrumental in lobbying for change that led to the forward capacity market and the supply curve markets that were imposed by the ISO. We're willing to work within that framework.

MR. KELLY: Thank you. David?

MR. MEAD: This is an issue that nobody raised, but I'm curious about it anyway, and I want to address it to Mr. Ott.

As I understand one of the pricing rules in RPM, it is that the price in an import-constrained capacity area can never be lower than the price in the adjacent exporting region. I'm thinking in particular, I believe, in the last auction in the southwest MACC area. Expected energy and ancillary service revenues were so great that the demand curve or the VRR curve was really low, and ended up being that the LDA or the zonal capacity price taken by itself was lower than the capacity price in the rest of the pool.

Have I gotten my facts correct so far? And as a result, the price in southwest MACC wasn't set by the intersection of the southwest MACC supply curve, and the southwest MACC VRR curve, but rather was set at a higher price such as the clearing price in the rest of the pool.

Have I got my facts right?

MR. OTT: I don't know if I would term it quite that way.

The import of it is essentially modeled in the auction. The auction is essentially a small optimization with sensitivity to management of supply and demand curves. So because the capacity import constraint did not bind, essentially -- because again, as you said, the total amount of supply coming in there did not work versus demand.

Essentially, they never bound. It wasn't constrained. It couldn't have been constrained. I agree with you. It wasn't because we went back and said, we're going to set it higher. It's because the constraint didn't bind. The constraint it bound in was the supply-demand power balance constraint, if you will, in what I'll call the

RTO-wide organization.

It's sort of like LMP. You never have --

MR. MEAD: Is it possible that the constraint could bind, and yet because energy and ancillary service revenues are so great that the zonal capacity pricing in southwest MACC or some comparable area could still be lower than the clearing price?

MR. OTT: I don't think it's possible, but I'm not going to answer definitively. I can't think of a scenario I can paint in my head right now that would say it's possible.

MR. MURRELL: I wanted to ask both Commissioner Centolella and Mr. Boudreau, in terms of the experience you've had with these capacity markets -- you've been doing this now for less than a couple of years. Do you have a feeling, based on what you've seen so far about how much longer we should wait to evaluate whether the current set of rules is by and large working and producing the right kind of overall result?

When do you think is the right time to evaluate, and what should be really focused on?

COMMISSIONER CENTOLELLA: Let me take a crack at it.

I don't know that I have a definitive answer for you. I guess first of all, I'm looking forward to Andy's report that's coming here in a couple of months. But I do think that any time you're starting out with an administrative mechanism, you're making a set of assumptions and compromises that are not going to be entirely reflective of what a market result would be.

Reliability First is projecting a 14-percent demand increase over the next few years, with a 1 percent increased in announced generation. I do have a real question about whether or not what we're doing is being helpful or sufficiently helpful to insure that the lights stay on for our consumers.

So I have questions about if we create administrative mechanisms which inherently have administrative conditions associated with them, and we're doing this for a year at a time three years down, what is the real impact of that on someone who might like to develop a new resource who needs a longer-term contract than that? Are we in fact facilitating those contracts, or are we impeding those contracts, and what is the implication of that as we go forward?

We're looking in the region as a whole at potentially being at least below the reserve margins that NERC recommends by 2011-2012. We're already getting past the time frame for building baseload generation in that region. We're at the point where demand options and combustion turbines may be the only remaining options by the time we have to do something, which is part of why we're taking an active look in Ohio at what we can do on demand options, and do in the near term.

I would not put off the decision too long, because ultimately we're going to end up in a pinch if we're not clear what we're doing. I can't give you a definitive answer, but I would say that the window for considering what to do is not indefinite, and we need to look at the kinds of experiments that we may be undertaking in Ohio on the demand side, and other people are undertaking.

We may need to look at what's happening in other markets, both in this country and around the world, that are structured in different ways. And we don't really ask the question, you know, is this the right thing to do before we get to the point where we're actually in a significant shortage situation. Because I think if we get to that point, the politics of what happens if we can't keep the lights on in the organized markets, we could end up with very bad decisions. So we need to be well in advance of that point before we undertake a more thorough review.

MR. BOUDREAU: I do think the timing of this will come out of how successful the experiment is. You'll know when it's time that you really need to make the change.

If we continue, in my opinion, to hit the floor in another auction, or potentially a third auction, there'll be a need to go in and relook at this. It may not be the change that we expect, but it will be clear that we're not creating prices that are going to encourage new construction and generation.

So we'll see it, and I think it will be clear well before we've gone into a reliability problem, at least in New England. We have sufficient generation, we might even have a little excess, as the result of our first auction. But I think it will become clear in terms of the timing as to when we do it. There'll be more than enough people willing to come in and say, we've got to address this issue right away, is the problem.

MR. KELLY: I have a question for Professor Hogan.

You mentioned that there are conflicting goals, people who are trying to solve the reliability problem and others who are trying to get forward energy hedges. There are different solutions to those two problems.

I didn't understand that. I thought in most cases, one solution would solve both problems. I have to ask you what you meant by that.

MR. HOGAN: Let me illustrate by an analogy that we're familiar with, or at least there's a lot of experience with it.

We have the State of New York -- and we're now talking about the day-ahead market. The day-ahead market people bid in their load, they bid in their generation, and they solve all this stuff; they figure it out. Then they get an answer from that about what the commitments and schedules are going to be. That minimizes the cost of all these kinds of things -- prices -- and people get energy contracts and hedge them for the next day and going forward.

After they finish figuring out all of those commitments, they figure out: wait a minute. Suppose we're wrong. Suppose the market doesn't have the right story here, and they haven't actually bid in enough load. They haven't dealt with the load appropriately, and we don't have enough generation to meet the actual load that's going to show up.

This is the reliability question that sort of has a second step in the day-ahead, which is a reliability unit commitment. This is to make sure that they have enough units to be committed to meet a forecast load that is produced by the system operator, which is different from the bids of everybody who's participating in the market. And when they're making that decision, they don't minimize the cost of meeting the forecast load. They don't provide an energy hedge for the forecast load, because there's no customers there who actually want to buy that.

What they do is, they commit additional units to minimize the incremental capital costs, incremental startup costs, of committing those units in case they need them, because the forecast load turns out to be the difference in what people bid in the day ahead. So they're using a completely different effective function. They're solving a reliability problem, not a market hedging problem. These things are carefully integrated, all these things.

They make whole payments in order to make up. That's a perfect analogy to this problem. If we're buying forward to get energy, and there's a good way to do that, it has a lot of appeal, signing bilateral contracts. If we're buying capacity, whatever that is, for reliability purposes, we should think about that as a separate product and deal with that for the reliability problem so that it doesn't screw up the marketplace.

But we have a little mixup here, and the root cause of that problem is that we don't have the scarcity pricing in the energy market that would cause a real scarcity situation. People sometimes say they're dealing with reliability, and there's a tension between the reliability requirements and the resource adequacy requirements, and all this squawking you hear back and forth, I think it's all crazy. But it's that conflicted role.

MR. KELLY: We're about at the end, but Mr. LaPlante and Mr. Ott are here as resources, in case their views on existing market operations would be helpful to the rest of the panel and us.

In the last minute or two, I just wanted to see if you had any observations from hearing the panel, that you want to respond to. This is the opportunity. We've been offering the opportunity mostly to Mr. Allegretti.

(Laughter.)

MR. LaPLANTE: I'd just like to add one idea along Professor Hogan's concept of the scarcity pricing. I think that in order to actually get the real benefits out of that line, you have to take it to the final step, which is, you eliminate the reliability requirement; you eliminate the one-day and ten-year requirement, and you have a smart grid or something hooked up, that let's those that haven't hedged themselves or had the energy in real time, suffer the consequences of that.

Now you're in a place where you don't have to worry about how much capacity you buy. People are only worrying about energy, and if they don't have the energy they need in real time, they disconnect it, so I think that's sort of the step beyond where we are in the current world where reliability truly is a public good.

I think that construct is an interesting one to keep in mind as we work through these issues.

MR. KELLY: I can't help interjecting. Actually, disconnecting customers, the utility or others who represent them, has served their needs well. It's not terribly political popular.

(Laughter.)

MR. KELLY: That we have some authority to take power from some and give it to others. Perhaps we have had some internal discussions over ten years, and if you do something like that, if somebody doesn't pay up, they get cut off, but implementing it, legally and politically, is far from a slam-dunk.

MR. LaPLANTE: I understand that.

MR. KELLY: I know it wasn't your proposal. Any final comments?

MR. OTT: I'll throw in mine. I think the concept of moving to an operating reserve demand curve and to more scarcity pricing, is obviously appealing to me, because I see so many benefits to doing it: Obviously, enabling demand response, empowering demand response to take control.

I guess my comment on it, is that I don't see it as an either/or proposition. The reason I went down the path of capacity markets, is the ability for us, us, collectively, to set a $10,000 price threshold. That was just, again, an unreachable goal.

We set capacity markets in place, and, again, I view them as a transition, and I do hope that we can implement more sophisticated scarcity pricing with appropriate adjustments to ancillary service offsets, which can make the capacity markets, again, wither away on their own, as opposed to being yanked away at the wrong times.

So, I think it is an evolution, and I think we can get there as an industry, but I don't think the answer is to radically change capacity markets, as they exist right now, simply because I think I do agree with Bill and with Paul, that the better approach would be to go down that road. Thank you.

MR. KELLY: I think we are done. I want to thank the panel. I'm very appreciative of your coming and spending time with us. Thank you very much. We will take a break until 3:15.

(Recess.)

MR. KELLY: Please take your seats. The last panel is about to begin. Welcome back. We've saved the best for last. The time for this panel will be a little tight, in the sense that on the last panel, we had nine persons, but seven speakers. This time, we have nine persons and nine speakers.

Mr. Sipe is going to make a presentation, not quite on the same topic as this morning, so let's get right into it. Our first speaker is Randy Rismiller, Manager of Federal Energy Programs at the Illinois Commerce Commission.

Mr. Rismiller, it's all yours.

MR. RISMILLER: Thank you. First of all, a disclaimer: My remarks are my own today and not necessarily those of the Illinois Commerce Commission or any particular Commissioner, but I do believe that what I will say, is consistent with the positions the ICC has taken in the past.

I'd also like to say that Illinois has the distinct privilege of having both PJM and the Midwest ISO operating in its state, so that's where I'm coming from. Today, I'd like to talk about efficient price signals and the impact of those signals on market participant behavior and the implications of that behavior for resource adequacy.

As we've heard, the resource adequacy construct argument has tended to fall into two basis schools of thought concerning how to incent development of infrastructure for long-term resource adequacy. One side promotes the administrative approach and forces arbitrarily-determined reserve margins; the other side advocates energy-only markets, and relies on efficient price signals to produce price behavior.

An efficient price signal for electric service, would reflect all of the costs and the risks associated with provision of electricity, including the costs and risks associated with the capacity needed to supply energy and operating reserves, and the operating day timeframe, as well as capacity, if any, above that amount, in the form of planning reserves, to ensure resource adequacy.

An efficient price signal would also incorporate into the market, all of the costs and risks currently dealt with separately through RTO uplift charges, and it would address scarcity conditions.

In the past, the Commission has expressed a willingness to accept and consider these so-called energy-only market designs, and it has stated this in a Midwest ISO case.

The Commission has also addressed support for market designs that provide the correct financial incentives, so that sufficient quantities of reserves of all types are available to the system operator at all times, but especially during shortage conditions, and that proper financial incentives exist to support any needed new entry, either supply- or demand-side.

For example, in its recent NOPR on wholesale competition in organized markets, the Commission acknowledged the importance of efficient price signals.

The Commission concluded that the existing RTO market designs may be unjust, unreasonable, and unduly discriminatory and preferential, because they prevent prices from accurately reflecting the true value of services.

The Commission concluded that such market designs may harm reliability, inhibit demand response, deter new entry of demand responses and generation resources, and thwart innovation. When price is disconnected from the value of energy, market participants have little incentive to act in a manner consistent with efficient markets.

I've elected to employ a market design for energy and ancillary services that allows the level necessary to induce the development of sufficient amounts of supply and demand resources. That appears to be because without sufficient price elasticity of demand, such a market design would generate prices that would result in voidable intervention or a set of conditions that would provide resource providers the opportunity to exercise market power.

This is sometimes what's referred to as the chicken and egg problem we heard about earlier today. Because it would require that prices be allowed to rise to efficient levels in order to produce investment needed to develop sufficient levels of demand elasticity, that would prohibit prices from rising to efficient levels so as to preclude the exercise of market power unless there's sufficient demand elasticity in the market.

In response to this conundrum, it seems to be desired by some to carve out certain costs, such as capacity and capacity planning reserves, for recovery via non-market or quasi-market mechanisms. One of the problems with such an approach is that capacity markets have other capacity constructs in place and under development that eventually force market participants to hedge forward and obliterate price signals necessary to induce price-responsive demand.

I think it's questionable whether there is this chicken and egg problem. But in any event, we urge the Commission to focus on market designs that do not have the feature of dampening price signals necessary to consent-induced activity investment in such things as advanced metering and infrastructure and the activities of the states to expose, to some degree, the load to spot market prices.

Thank you very much.

MR. KELLY: Thank you, sir.

Next is someone well known to all of us, Joseph Bowring, market monitor for PJM.

MR. BOWRING: Thank you.

I'm going to focus on a fairly narrow issue today, but look forward to having a broader discussion.

I wanted to address directly some of the questions and issues raised by Jim Wilson in his paper for the APPA, and also raised by other folks. Let me state at the outset that it's my view that there are certainly some cases of the RPM design that need to be addressed and that should be addressed: the extent to which performance incentives are attenuated time and again at the outset, which you've heard a lot about today; the level of transparency on some key rules and parameters, the question of whether the single-year price is adequate, the cap on the FRR, just as examples.

Nonetheless, all these issues are manageable.

They're not fundamental flaws in dealing with the RPM construct, in fact, although there have been some fundamental attacks on RPM today.

The APPA approach seems to take issue with the way in which market fundamentals are expressed, rather than a fundamental issue with the RPM market design. In particular, if we start with supply, the claim is that supply is fundamentally misstated. The supply curve has shifted too far to the left, and it's too high compared to a competitive outcome.

As a general matter, those assertions are not correct. Clearly -- and we made this clear from the outset in all the conversations about capacity markets -- capacity markets have structural market power endemic to them. That's unavoidable. In that case, and in fact in every case in the market, there are always incentives to exercise market power. But we have very clear and forceful rules for combating market power in the RPM market of PJM, and in particular most offer requirements and offer caps are good market power mitigation solutions, contrary to the claims. In fact, there's been no physical withholding. Every single megawatt is accounted for.

It's also not accurate to say that outage did or can be regulated in order to withhold from capacity markets. PJM has accurate outage data. It's not possible to increase the enforced outage rate in order to make an inappropriate offer in the capacity market. In fact, it seemed the reverse in some cases. Generators have offered in more capacity than consistent with their historical and actual forced outage rate.

There's also the claim that we've seen uneconomic exports. We've looked at that question. There are no uneconomic exports in our view. In fact, the RPM market includes -- it gives you the opportunity cost mechanism, which has in fact permitted exports, which otherwise would simply have been exports, to make an economic decision about which is the higher-priced market.

The critique also, I think, mistakenly focuses on something that's called in the jargon of the tariff a PIR, which is in fact the mechanism which permits old generation to recover at offer caps the investment associated over a period of time with maintaining capacity resource. This is a critical element of our design. In fact, those type of things that Mr. Wilson and others suggest should be done for new entry, which is to permit the recovery of those costs over a number of years and permit those to be added to our forecasts over a number of years rather than simply to be added to one-time recovery on the demand side -- that's the supply side, which has allegedly shifted too far to the left.

On the demand side, we have too much demand. That's been responded too in some detail by PJM. But what I would say is that, to the extent that reliability standards are overstated, that's a matter for the stakeholders and the FERC to discuss.

It's certainly not my view that the demand curve is misstated. Ultimately, though, the APPA paper says among other things two critical things. One is, it says that at the outset the price is too high. Particularly, it's too high compared to what the daily market prices have been, or in fact what the simulations have been. Later on the paper says prices are too low. It says the prices are not adequate to overcome regulatory and political risks, and in fact recognizes that CONEs are absurdly low.

The point there is, this suggests a metric that suggests the appropriate metric for whether prices are too high or too low -- if you don't know, the metric is whether the prices are adequate to provide incentive to invest in the capacity if it's needed. I don't think there's any indication that that price at the margin is too high.

The other question -- can I do this? -- which I think was raised and needs to be addressed very explicitly is the question about windfalls. I think the point there is that the windfall question has to be distinguished very clearly from the question of incentives at the margin.

Incentives at the margin are if anything too low in the RPM market.

But there's still a question about the impact of state decisions on whether or not there are windfalls. It makes sense to address that question explicitly, but it's important not to confuse that with a margin signal. That's a one-time issue, and will not persist as the old units roll off.

I'll stop there. Thank you.

MR. KELLY: Thank you very much. Next is Randall Speck, an attorney with Kaye Scholer, speaking on behalf of both the Maryland Public Service Commission and the Connecticut Department of Public Utility Control. Mr. Speck.

MR. SPECK: Thank you very much for the opportunity to speak today. I have represented Connecticut for some years, and Maryland the last couple of years, specifically with regard to RPM and SPMs. So I'll speak with regard to both of those.

I think it's fair to say that states demand that payments reflect some tangible benefit they want, some proof they're getting value for the money they're paying. States have a lot of different objectives; however, it's not just reliability, it's not just cost. It's also environmental issues and other state-driven issues.

The bottom line, however, is do the high capacity payments we're paying now produce value for customers, and if they don't, I think you can expect that regulators will intervene.

I want to compare SPM and RPM in three areas. The first is how they handle the transition period, where there are steady state auctions. The second is how do the capacity mechanisms facilitate state reliability, and renewable resource objectives? Finally, how do they mesh with energy and the ancillary services markets?

The transition periods, I think, have to be looked at separately. We're now committed in PJM through 2011, May 2011, with prices that were done all during this transition period. The fact is that during that period, there really wasn't competition. Therefore, you didn't have any discipline on price. That's the key function during that time period.

As a result, you had a very steep supply slope, at Jim Wilson has said, rather than a flatter supply curve that you would expect if there were true competition for new resources. New England handled that very differently. They simply set the price during the transition period.

PJM, on the other hand, attempted to hold auctions during that time period, with a much shorter planning period that didn't allow new capacity to participate.

The second key area of comparison is how they mesh with state objectives. The first objective obviously is reliability. Every state is very concerned about that, particularly state regulators. The SPM has obviously shown some promise in this area. They've attracted a great deal of new generation and new demand response, critically new demand response.

RPM has not been nearly as successful thus far.

A lot depends on what happens in this auction that's taking place this week. Maryland and the PJM states will be looking very carefully at what happens here, to see whether we in fact are going to get reliability through these auctions.

With regard to renewable energy, I think it's equally important that the states have adopted very strong financial incentives, to get renewable resources in their states and to get demand response.

They have programs for both demand response and energy efficiency. There's a lot of participation again in New England, and much less participation particularly relative to the entire mode in PJM.

That's the focus, I think, that the Commission can really be effective in pursuing the energy efficiency and demand response, particularly in PJM.

The third area of comparison is how these mechanisms mesh with energy and ancillary services markets. Many people have talked about the missing money.

Obviously, they intended to provide that missing money, but the load doesn't want to have to pay for it twice. We only want to have to pay for it once. Therefore, you have to deduct the energy and ancillary services in some fashion.

In New England, it's done very effectively, we think, with the PER adjustment. That has worked or will work, we think, very effectively through skim-off of spike pricing.

Ultimately, we believe that mechanism, I think, as Dave LaPlante suggested, can be transitioned into the period when demand can actually respond to price, and it will make these capacity markets certainly less important as we go through that process.

RPM, as others have said, has a significant lag in the deduction of energy and ancillary services. It's not at all contemporaneous. That is a very key and important difference.

In New England, the SPM permits essentially another incentive, as Dave LaPlante, say, for performance, by deducting these PER revenues.

In sum, SPM has generally performed, we believe pretty well, by fixing capacity payments through the transition, attracting demand response and energy efficiency consistent with state objectives, and harmonizing capacity payments with energy and ancillary services revenues. RPM has not performed nearly as well on those three characteristics. Thank you.

MR. KELLY: Thank you. Mr. Sipe, you've been introduced. You're on.

MR. SIPE: Thank you. I just want to spend a little bit of time on some topics from the previous panel surrounding demand response and the market designs that might be necessary to get some.

I think I heard Mr. Fuller say at one point that there was confusion between looking at designs on the wholesale level and designs on the retail level, and we really didn't need to go there.

I think in fact we do need to go there, just pass through the wholesale cost in some sort of fashion into the retail load. I think the design of how you get there, that wholesale has got to start being more compatible, not less compatible, at the retail level.

That leads to the question of how these things ought to be designed. We heard Mr. LaPlante say in reliability, it's still a public good. I heard some of the staff members, I can't remember who, saying there are some political problems, either forcing people to shut off or drop their load.

I'm not sure if by calling those political problems the assumption is that they are also not sound social and economic reasons why a product that drives people off the system with some degree of regularity or even irregularity, creates more societal inefficiency and more societal problems than one that's defined so it doesn't.

But I do not think that we should dismiss political insights from the people that talked about just and reasonable rates, who after all were not economists so much as humanists, trying to figure out how we were going to sell this product so that society would work better.

I think that if risk were free, allowing energy prices to spike to extraordinary numbers so that your kid can leave the basement lights on and bankrupt the family, would be okay. But risk isn't free.

There is some thought to the kind of a system where the risk of failure is that steep, which is I think we have a one day and ten year reliability requirement. I am sure that if we let prices go that high, it will be effective in getting demand response.

I am not sure that it will be efficient. People will certainly react to things, but the automatic presumption that it is more efficient to have individual consumers or small groups react with individualized options rather than central station technology, rather than transmission-based solutions, rather than other things that require things like a planning reserve, like a more forward-looking market, I'm not sure we've truly addressed that balance in figuring out where it is efficient.

I'm also concerned that driving the price that high creates market power in suppliers who are selling in a hedge. Someone is selling you a hedge against him, and there really is a possibility your children will starve. There is a great deal of market power in that hedge if you truly take the risk of consuming at the wrong time.

Comparable to risk of interruptions, you have basically caused interruptions. You have basically caused the harm the system was designed to avoid. I'm not sure that is always the best model. I believe that there is room, as I said this morning, to set up a system where those types of prices are available for those who can find a way to capitalize on them.

Certainly if they're that high, people will be looking to make money doing it. I seriously question whether it is fundamental societal redesign of what this product and what it's expected to do and what I expect to be a very energy-intensive economy, electricity-intensive going forward.

To simply assume that the way to do it is to let the price go where it is, and letting that responsibility directly induce consumers. The other thing I heard is that the people that can't respond, let's find some way to deal with them, take them out of the market.

Well, I would say let's take the people who can't respond and the people who can respond out of the market, and then get a good easy way to voluntarily get people back in, a way to get back in, and they can decide.

Those are the people who give some level of volatility they can respond to effectively with good long-term price signals that drive efficiency. I think the two paradigms need to be thought of a little more carefully. I think the two paradigms need to be thought of a little more carefully.

I think I'd framed the questions I've had. I'm not sure I know all the answers.

MR. KELLY: Thank you. Our next speaker is Robert Ethier, Director of Resource Adequacy and Chief Economist, ISO New England.

MR. ETHIER: Thank you for the opportunity to be here. Probably what's most relevant today is that I was primarily responsible over the last four years for implementing and executing the first forward capacity option in New England.

My comments today are really going to be observations that come out of that implementation process and running that auction. Those of you with longer memories will remember that I was also the market monitor in New England at one point, but I'll defer all discussions to Joe, who would relish the first point I'd like to make in this response to some of the comments that you heard earlier.

In the New England experience, in the first auction, the new entrants were not all limited to incumbents in the market, which I think is a very good sign. Interestingly, actually of the new generation proposals that we saw, and I want to be careful to not discriminate here, I sort of feel like we fall into the old way of talking when we talk about these markets, as if they're solely designed for generation procurement.

But the explicit intent of the FPM design was to treat demand and supply on a level playing field. I'm going to try to continue that in my comments, but on the generation side, we actually got a lot of developers who are not affiliated with large incumbents in New England.

Their clear business plan was to develop the project, get it approved, get it qualified, get it cleared and very likely spin that project off to whomever would buy it.

For the market purchasers, they were behaving as a small new entrant, which is exactly what I think we should be happy to see in these markets.

Not that large owners aren't also welcome, but I think it's a good sign when you have small competitive suppliers coming in. Another interesting observation of the results from the first auction is the amount of incremental investment that we saw from existing facilities. To me, that's another good sign that the price signals and incentives that we're providing are effective.

I think a lot of folks recognize that the most cost-effective entry is incremental additions to existing facilities. We had a nuclear plant that upgraded and participated in the auction. We had other plants like hydro plants that offered to rewire their generators to produce higher output for different water volume.

They would replace their runners so they have more efficient water flow, and again increase their output. So we had a fairly large number of projects that reflected that incremental investment, which is again a good thing. It suggests that the market signals are penetrating the way we would want them to.

Third, and this might be a little bit of heresy, but the forward markets that we have could well result in building less transmission. It strikes me that it's a good thing. Historically, where we had monthly capacity markets, it was very hard to predict the new generation. But we'd have it three to four years, which is the transmission planning horizon.

With our new forward market, we actually have the possibility of deferring some transmission investments based on generation or demand response. That clears in the auction, and I think that can only aid efficiency.

The auction is run out of the transmission planning department or the system planning department, and a very explicit link and the push to increase that link between the planning process and the market results, I think, again not only improves the efficiency of the overall system.

Fourth, transparency. The level of transparency in this market is remarkable. We filed with the Commission a list of every resource that's bought by participants and the megawatts they participate with. Once it's out, we publish all the winners.

That is remarkable, and it's, I think, both to build confidence in the market but also to inform potential new entrants of what the playing field looks like. So that's another positive aspect.

I guess I have time to fit in this part, because I have 35 seconds. I think that FPM is not at all inconsistent with the idea that we should increase scarcity prices. In fact, I think it facilitates it. It sort of eases the path to higher shortage prices. Thank you.

MR. KELLY: Thank you. Next is Robert Weishaar, with McNees, Wallace and Nurick, appearing on behalf of PJM Industrial Customer Coalition and the NEPOOL Industrial Customer Coalition.

MR. WEISHAAR: Thank you, Kevin. Good afternoon. I'm Bob Weishaar. I'm an attorney with McNees Wallace. We have the privilege of serving as counsel to some of the largest industrial and commercial customers of PJM, an ISO in New England and elsewhere.

I want to thank the Commission for opening up this dialogue. Customers are confronting some serious market design issues and increased power costs. At this time, it makes sense to step back and figure out whether what we're doing is correct or incorrect.

I also want to take this opportunity to commend the RTOs on their performance outside of market design issues. I don't want this forum to turn into any form of RTO bashing. RTOs can and do provide value to customers, in terms of regional dispatch, independent coordination of transmission, independent transmission planning and independent publication of objective, transparent and auditable information.

For market participants, those are all very valuable services, as I'll get to later when we discuss the PCA proposal. RTO performance is the backbone of that proposal. Just a few comments on the existing capacity designs.

Customer's problems generally with the existing capacity design is they don't really live up to a fundamental, contractual principle of bargain for exchange.

Instead of buying a real product or a real service, customers are being forced to spend billions of dollars each year on price signals, and are asked to take on faith that the signals will attract not only new investment but importantly the right investment in the right place.

If the money is to be spent, and it is being spent, we're now on the hook for dollars out through 2011, soon to be 2012. Customers would much prefer spending the dollars on actual clean and new efficient generation.

We've heard comments this morning about maybe it's too early to take a look at capacity designs again. Customers are on the hook now three years out. We don't have an objective or a standard.

What I've heard is that we'll all kind of know it when we see it. If it's not working, everybody will come back to the Commission and will complain again. We need some measure of success.

The third comment on the existing design is we need to have a check on proportionality. Yes, we're spending dollars. Yes, we're getting some incremental megawatts. But there's no checks on whether the dollars being spent for the megawatts are proportional or rational or just as reasonable.

If you put enough money on the table, of course you'll get new megawatts. But the bigger question and the question more fundamental to the customers is, is there balance between the two.

The mismatch between the customers and the outputs of today's organized markets prompted exploration and development of alternative market designs and I'll comment on each of the two designs at issue today.

While the American Forest and Paper Association proposals takes a step in the right direction, by better recognizing the interrelationship between energy and capacity payments, the proposal does not appear to deliver much in the way of price reduction benefits to customers.

The FPO raises the possibility that suppliers will demand more in capacity payments, while assuming the risk incremental to the risk they face today of supplying energy at a pre-defined strike price.

If the Commission is looking only to tweak the existing capacity market design proposals, it's worth considering. However, the proposal stops short of tackling, in our opinion, the fundamental market design problems that continue to force customers to spend dollars and get not a lot in return.

The PCA proposal, by contrast, does it with a more comprehensive and all-inclusive scope. The proposal seeks to deploy competitive forces where competitive forces may exist. It admittedly seeks to deploy cost-based elements where competitive forces may not exist.

The proposal was designed for customers, small customers and customers from all stripes should find benefits in the proposal. First, the proposal recognizes that RTOs can and do now play a useful role in system planning.

They design and plan for transmission expansion. That is a long-term look. They make certain assumptions in the transmission. It seems to be a point that was overlooked this morning.

Second, the proposal actually meets the principle of the bargain for exchange. Customers pay dollars; customers get new generation, of the type and in the location that is deemed necessary by the RTO.

Third, we're focusing on physical solutions and providing stable, long-term opportunities for revenue recovery. I'd be shocked if the investment community found that as a negative. Looking long term, that's what we see in today's markets.

I understand this, but from the retail perspective we see states reacting to wholesale market problems in many different ways. Some are re-regulating; some are extending rate gaps. Some are proposing power authorities, but all working within the confines of their states.

I think we're missing a huge opportunity here to capture on what we've developed thus far, in terms of regional infrastructure, and unless we get the wholesale market design right, other states are going to take a similar approach.

From a customer perspective, that's not necessarily a good thing. We have an opportunity. We need to seize the opportunity and again thank you for your time today.

MR. KELLY: Thank you. Next we have Dr. Eric Woychik, Vice President of Regulatory Affairs for Converge. Welcome.

DR. WOYCHIK: Let me thank the Commission for this opportunity to be before you again. Converge supports organized competitive electric markets and capacity markets, no doubt about it.

As background, Converge participates directly in capacity markets in PJM in New England, provides long term capacity contracts based mainly on residential loads, and provides equipment and self-regulating services to clients.

We cover the spectrum. We manage about 1,800 megawatts of demand response capacity contracts, and have about 4,500 megawatts of installed capacity in place.

Importantly, Converge asks the Commission to recognize the market requirements to integrate residential DR, and that those are different than market requirements for commercial and industrial DR. It sounds very simple, but it's very important.

In this light, Converge's needs are really to make the business case work and in part, the capacity markets are essential to do that. Specifically, we ask the Commission to look at the following seven matters: access to the same revenue flows and benefits as generators, including equitable settlement; market rules that enable DR to provide maximum market value and transmit data needed for effective demand response; market fundamentals to ensure stable pricing and transparency; effective RTO governance, ISO governance as well, to support decisions that enable demand response; the ability to provide capacity only during summer months or for the entire year, depending on the kind of DR provided.

Certainly, there's a distinction there in the way we have to operate in PJM versus the New England ISO; capacity prices that reflect occasional constraints.

A related approach for the business case analysis of DR is presented in the most recent Public Utilities Fortnightly article that I've written. So Converge really asks the Commission to ensure greater flexibility in capacity markets, in order to allow these two categories of DRD sources to provide maximum value.

Finally, Converge offers a summary in the outline we've given you. Hopefully, you have copies of that and I apologize to others who don't. Really, this is based on the Commission's previous criteria to evaluate PJM's capacity markets.

Those criteria, five of them, are very relevant, I think, to the current debate and discussion. To induce DR investment and meet resource adequacy, each attribute should be used to revise and reform current capacity markets.

Let me now point to three particular issues that certainly, I think, are relevant here. PJM's approach to fix the netback of generation and transmission in the energy market LMPs, which is not directly related to capacity markets. Certainly, that decision has already been made.

That relates directly to the Commission's criteria, particularly integration of energy market revenues. The whole picture needs to work. As has been said numerous times, enough to make sure capacity markets work and are integrated with energy markets and with operating reserves.

Second, allow for preferred operating reserves, benefits to flow, so that there can be current benefits. In ISO New England situation, there's no opportunity for us to play in operating reserve markets. In ISO New England, there is an annual commitment that's required to provide DR. In PJM, we think that's quite different.

There's five critical months that we have to provide those kinds of things, where in the PJM market we can participate with residential loads and equally with industrial loads. In the ISO New England market, those prices are averaged, and we're forced to participate, particularly for residential loads.

So price averaging is certainly an issue on the one hand, and need for consistent revenue, and that's providing by operating reserves and capacity market revenues. Those are both essential.

Let me stop there and thank you. I look forward to a discussion.

MR. KELLY: Thank you. Roy, you've been introduced. Take it away.

MR. SHANKER: Thank you. Because I have spoken before, I'm just going to try and hit some points. So this may be a little disjointed and jump around a bit.

The first observation I would make goes back to Bob Weishaar's presentation. It also ties in with my earlier comments this morning. It's amazing to listen to a representative of large industrials advocating 20 year central planning and procurement, when the process that most of us are in today was initiated by those same companies, many of whom are my clients, struggling very hard to get out of stranded cost obligations and get access to the wholesale markets when they were in surplus.

You all may need to think through why they were in surplus, and why they wanted to get out of stranded costs, and think about my comments this morning, about average and marginal costs, to understand where these proposals are coming from.

It's just a continuum of the same things over and over again that I talked about earlier. The notion that somebody would be strongly advocating a 20 year central planning after what we've gone through is pretty difficult in some ways to understand, other than for the short term, myopic. We have an opportunity to escape where there seem to be rising marginal costs.

The second thing is I'm all on board and would strongly support the notions of scarcity pricing that Bill and others talked about earlier. It makes perfect sense. We have to have the mechanisms we have now until we get that in place. One of the good things is we have the luxury of having time to get that in place. But the faster, the better.

Similarly, if you go back to those two or three working sessions on this topic, I put in the proposal about a weighed phase-in to scarcity pricing within the construct of the capacity markets.

Bill, it doesn't depend on the stakeholder process, so it's hard to get that number to go up by ten in the stakeholder process overnight, and I'd like him to come to a meeting, to be the first one to propose it.

(Laughter.)

MR. SHANKER: But on the other hand, we can get from here to there by simply putting in the scarcity pricing and raising caps and seeing the process evolve within the context of the capacity market that eventually will become superfluous. The price will go to zero. So that's a very reasonable thing to do.

I was concerned at several points about the next PJM auction being some sort of a standard-bearer or test concept. It won't be. It shouldn't be perceived that way, and I think it would be a mistake to look at it that way, if for no other reason than we know from the get-go, from the market monitor, from PJM itself, from just about everything we've seen anywhere, that the reference prices for the CONE are off by about 30 to 40 percent.

The expectation that this market is going to adjust quickly and magically, and people are going to ignore the wrong price and be some sort of proof of concept just isn't going to happen.

I think it would be disservice to everyone to put those kind of expectations on the market. In that same vein, I wanted to clean up a couple of items. The AFPA proposal, I want to emphasize that what's being proposed is a completely different product.

This is a pre-end product. It's not one that can be sold in the market. It's not one that can be integrated with what PJM is doing, but it's one that will come at a significantly higher price. If you want to put something like that in place, of an LV call, the physical capacity behind it, you can do that.

But then expect to see the CONE, whatever we're going to call the new concept of CONE, significantly higher. What's been missing from this discussion is anybody empirically telling you what they think that call is going to cost. I would strongly recommend that before you do anything like that, you start asking people what that call will cost.

Price discrimination, an underlying theme in almost everything we have heard, from the concerns about whether or not the bargain is being kept, to why aren't people getting paid that have existing capacity.

True, money is being transferred inefficiently to the proposal and agenda. Underneath all of it is price discrimination. Indeed, if you can get away with it and pay less than a clearing price to some participants and effectively sort of seize their assets for a fungible good, you will save money.

The Commission has spoken pretty clearly and continuously about this, and recognized that it's not something that's appropriate and that it's not good market design, and it doesn't lead to the right long term incentives for retaining and attracting new capacity.

I would just urge you not to lose sight of that as we go through another one of these cycles of political pressures and concerns, as marginal prices start increasing. I've got some more. We'll be able to talk about them as we go forward. That's it for now.

MR. KELLY: Thank you. And last is Steve Elsea, Director of Energy Services for Leggett & Platt.

MR. ELSEA: Thank you. Good afternoon. I want to thank the Commission for the opportunity to share our perspective of the emerging capacity markets. First, a bit about Leggett and Platt.

Leggett and Platt is a diversified Fortune 500 manufacturer, that conceives, designs and produces a broad variety of engineered components and products that can be found in virtually every home, office, retail store and automobile.

Leggett serves a broad suite of customers that are comprised of a who's who of U.S. manufacturers and retailers. We're celebrating our 125th anniversary, and in that time, our company has grown into 22 business units in more than 250 facilities located in 20 countries, operated by 24,000 employees partners.

About 75 percent of our facilities are in the United States. As you can imagine, our production facilities and their respective hours of operation are very diverse. We have small assembly plants that operate one or two shifts a day, five days a week, to large 24-7 integrated processing facilities, where feedstock is turned into machine components, for example.

Leggett operates one of the largest electric arc furnaces in the world at Sterling Steel Company, located behind PJM. Although Sterling's 15 megawatt rolling mill operates 24-7, the 85 megawatt electric arc furnace operates from Friday evening to Monday morning. More on that later.

As a large power user, our perspective of capacity markets may differ from several of our peers. The emergence of ISO-RTO capacity markets is a logical evolution in the absence of demand or capacity pricing.

The cost to serve energy subsidizes the cost to serve capacity, which inherently creates disincentives for supply side investments and demand response participation.

Prior to wholesale and retail deregulation, in the days of the regulatory compact between utility and customer, cross-subsidization between billing determinants and even between rate classes shared multiple purposes.

Often, however, that cross-subsidization had unintended consequences, for example. Demand costs that were much lower than the costs to serve that marginal capacity reduced investments in technologies that specifically mitigated peak demand.

The unintended consequence was lower utility system load factors and higher capital costs to meet new peaks in the entire electric supply chain infrastructure.

In the best case, those costs became embedded in those kilowatt hours aggregated within the time of these rate blocks that were typically spread around an entire season. In the worse case, every kilowatt hour, regardless of time of use or seasonality, subsidized the marginal cost of every new KW added to the system peak.

In one of my first presentations on the subject 30 years ago I used a very simple illustration that is included in the presentation that I provided to the staff ahead of time.

After scale economies and firm allocation fees of generation had peaked after the 1973-74 Arab oil embargo and the subsequent rise in fossil fuel prices, and during a period of double-digit inflation, the industry had to move beyond bundled rates to pricing structures that more accurately reflected the true cost of service.

Now fast froward to present, today. Improvements in technology and communications provide real time access to behind the meter energy usage and the supply side marketplace. Deregulation is producing transparency in the market. The argument can be made that the bundled energy and capacity pricing construct accurately reflects the cost of service on a real-time basis.

We have all witnessed volatility in the various markets as a result of the supply-demand dynamic. Unfortunately, hourly price volatility provides too short a time horizon for capacity to be valued in such a way as to produce adequate incentives for supply side investments and demand side management.

I'll use Sterling Steel as a case in point. I had mentioned that Sterling operates a 24-7, 15 megawatt rolling mill and an 85 megawatt electric arc furnace that operates only on weekends. The weekend operation takes advantage of the lower hourly prices behind PJM.

The load grid depicted a presentation that I filed with the staff earlier, and illustrates the typical week where the EAF is brought on-line after 6:00 p.m. on Friday and is taken off-line on Monday morning.

Recent business demand, though, has necessitated that we extend the EAF's operation until Tuesday morning. The difference in energy prices in the peak five by sixteen hours on Monday is not great enough to justify maintaining the weekends-only operating schedule.

However, the RPM provides a sufficient price signal for us to plan around PJM peaks. That Sterling is located 75 miles south, behind MISO. We'd absorb the differences in energy price as we are now, and extend weekend operations without regard to system peaking conditions, potentially contributing to new peaks and/or affecting he integrity of system reliability.

Additionally, the RPM has provided the necessary price incentives to review our 24-7 sourcing strategy for the rolling mill. For example, we're currently reviewing a renewable source that would supply 10 megawatts of base load. Our particular interest in this product is that it includes capacity as well as energy.

Again, a typically energy-only construct, we would maintain our present strategy of sourcing base loads with only hedges. As another hedging strategy, we have enrolled three megawatts in the PJM Interruptible Load for Reliability program.

Given the RPM price signals for the auction period 2009 to 2010 and 2010 to 2011, we are relocating the two megawatt standby generator from a closed facility in Arkansas to Sterling.

During the due diligence phase of transferring this vital asset, we only considered those Leggett facilities located behind RTOs, ISOs, where capacity was valued. Again, the RPM was integral to that decision.

Just a few parting comments. In the absence of capacity markets, load-serving entities have difficulty providing capacity. Prior to the emergence of capacity markets, LSEs tended to undervalue capacity, thus restraining supply and demand investments.

We commend the FERC for its role in shaping capacity markets and encourage the Commission to promote more transparent long-term forward capacity markets that would increase supply and demand investments.

Thank you again for the opportunity to present our comments.

MR. KELLY: Thank you. Questions?

MR. MURRELL: I have a question. Roy, you had mentioned that prices are too high to be placed in the RPM auction, and you typically had mentioned a price was fine. I thought that it was going to lead to or at least not promote getting a good result.

Is there something about that pricing structure that needs to be fixed right away?

MR. SHANKER: What are the rules about that? The Commission issued an order and rejected PJM's adjustment of the cost of new entry. So it's fine to discuss that? We're okay. I never know what your rules are for that.

MR. KELLY: We prefer not to get into great detail on that. We're not primarily here to do that.

MR. SHANKER: I understand.

MR. KELLY: I think the question was more or less about the timing of the change, as to how pressing in the eventual change.

MR. SHANKER: First, if you understand that you're going to enhance, but for adjusting, keep your hands off the process for 20 years, this is not earth-shaking. We must recognize that the CONE sets quantity, not price.

That's what it does in the long run. There's a true cost to entering the market, and us guessing at the number and being five or ten percent off one way or the other isn't going to change what it really costs to build.

So as we equilibrate around that true price by adjusting the curve, we wind up changing the quantity that actually clears, because there's a true price, and then the curve we're guessing at goes across that horizontal line.

In the long run, is it a big deal? No. But tomorrow, it doesn't mean a whole bunch of people are going to offer a capacity that costs hypothetically a $150 when the targeted curve is kept.

Is it structured in such a fashion that it's referenced against $100 price? Yes, it's going to have an impact. If you have the right attitude that you're judging performance in the long run, and you don't look for a single auction, then it's not relevant.

The one I hear everyone saying this is capacity and this will prove whether it works or not. I get very anxious when we know going in that there has been a dispute about whether or not the proper prices are being shown.

MR. MURRELL: Bob Weishaar, you promote or you support the Portland proposal which, if I understand it, would lead to the rolling creation of long term gain.

If in the short term the RTO guesses wrong and the commitments that are entered into today over the next 20 years five years from now are leading to excessive reserve, which presumably means higher prices for consumers, where are we going to be from your point of view at that point?

MR. WEISHAAR: I think the saying risk is presented today, and again it depends on how far out into the future the RTO looks, in terms of load forecasts and reserve projections.

Under RPM today, the RTO was doing just that, and there's not a true-up. If PJM, for example, overestimates the amount of resources that are needed, we don't go back three years out and say well, generation, we don't really need this 5,000 megawatts. We're not paying it. So the same risk exists either way.

Under the proposal, if the RTO procures it, that creates a binding commitment to pay, just like it does when the RPMs today --

MR. MURRELL: Maybe I misunderstand. But I had the impression that for PJM and for New England, although that commitment might be made today for three years out, in the case of new generation there may be a five year payment required.

But essentially, the commitment's being made for a year. Is there a difference?

MR. WEISHAAR: For a single year into the future, yes. Take the example and look at it through the PCA proposal.

If the RTO looks out five or seven years, and determines that X amount of generation is required, and you get to Year 7 and peak load really didn't grow the way they thought, there's basically an over-procurement of generation.

That is a risk under the proposal. But the generation would have been procured. It would have been a financially binding commitment, and you use that excess looking out into the future then, to procure. I mean at some point, load will continue to grow.

At some point, the capacity will have value. Whether it has value in the precise year in which the RTO believes it will have value will depend on the accuracy of the forecast.

The same type of risk exists on the transmission side today, where PJM looks out over an extended period of time, makes certain assumptions, comes out with a regional transmission expansion plant, and that creates a good faith obligation on transmission owners to construct those lines.

Ten years out, if the transmission line is determined not to be needed and is already built, again it's the same risk.

MR. KELLY: Dick?

MR. O'NEILL: I agree that ISOs make decisions that create risks. But when you switch from transmission decisions to generation, you're changing the magnitude of the cost of a mistake. You said you wanted clean, new efficient generation. Was it a code word for not coal?

(Laughter.)

MR. WEISHAAR: No sir.

MR. O'NEILL: Could you elaborate on that? Bob talked about the existing of co-existing facilities, and seems to be happy with them, and you seem to want shiny new assets.

MR. WEISHAAR: Climate change is a pressing issue. I don't think, through an organized market design perspective, we really addressed it the way we should.

There will be requirements into the future, and it's almost inevitable that there will be requirements. But we'll limit the types of fuels perhaps that we can use for generation, that needed to be factored into the mix. Somehow currently it's not.

Take the FCM, for example. There's generation, I think, in the queue someone said this morning. There's 8,900 megawatts of generation that could be bid into a future FCM market. There's also the data that has natural gas-fired generation.

Looking at that from not an environmental perspective but a gas delivery perspective, is that the right mix of generation? Is that going to meet long-term reliability needs in New England? Is the FCM going to price that? Is it going to get the right mix of generation?

We don't know that. The answer we heard this morning from several panelists, as to whether these capacity designs will work or will not work is we'll know it when we see it. I think we owe customers a little bit better response than "we know it when we see it."

MR. O'NEILL: My recollection in the Portland proposal was that it didn't have any specific generation mix associated with it. But I think you're saying you want to put a type of generation mix in it.

MR. WEISHAAR: The Portland Cement Association proposal says that the RTO shall coordinate with the state and identify, if necessary, the types of resources that are needed.

So for example, if quick start units are needed in Connecticut, that would be factored into the procurement decision. If REGI is in place and requires certain types of generation or prohibits certain types of generation that will need to be a vital input.

The proposal does not say all new generation shall be X type of fuel. But it certainly would take into account and would have to take into account any limitations on the types of generation or the types of fuel that could be used.

MR. O'NEILL: Why wouldn't we just give these programs to the states? I mean if the states want to plan a mix of generation, why hasn't the state taken on these types of notions?

MR. WEISHAAR: They could. We would start realizing the full potential of regional action and regional planning. In partial response to what Roy said, he had to express shock and awe that industrial customers would line up behind this proposal.

I think we're not -- the PCA proposal is not "put the genie back in the bottle." It relies on competitive forces. Putting the genie back in the bottle would have the utilities doing integrated resource planning and having utilities making potential multi-generational investments, and trying to roll that into rate base.

This proposal doesn't do that. This proposal has an independent entity looking at all these elements in an integrated fashion, generation with any type of limitation takes into account if the muni wants to go out and build its own generation and meet its resource obligation that way, fine.

It takes that as a given. Industrial customers would have that option too. States would have that option. But the more kind of molecularly yet in terms of solutions and planning, I think we lose out on the benefits of regional efficiency. That's what the proposal was trying to get us back to.

MR. O'NEILL: My last question. I forgot to ask it earlier. There have been complaints that even though there's a lot of transparency, that there's not enough. I guess my question is, and I'll commit the sin that Kevin almost committed --

(Laughter.)

MR. O'NEILL: Isn't more transparency necessary, or wouldn't it be a good idea because a lot of the arguments about why these things aren't working, I think is exercising market power. Some of them go back to the fact that there is enough information to get upset, but not enough information to make the case.

(Laughter.)

MR. SHANKER: I'll answer in the context of RPM. For the most part, yes. I have a number of clients, and I try to stay away from specific prices, but I'm very impressed by some of their simulations of auction results, and some of the consulting services that are providing them.

So presumably somebody's able to replicate in advance and come pretty close. That says a lot about transparency of the process. Are there some areas that could do some more? Probably.

I think particularly there's one item in particular that people get as an input that is necessarily transparent. It's probably the C-TEL values. PJM tells you them. It's complicated.

The C-TEL analysis I understand pretty well. The actual head count on the C-TEL calculation is not transparent, at least not to me. But in general, that process is pretty good and I think that the people can predict and the kind of precision that I've seen is indicative of that.

MR. ETHIER: An observation on that question, and also it circles back and address John Boudreau's question from earlier about why so many new resources and FDM left in the first round.

I think New England is sort of roughly at about the appropriate border for information provision. I think the next step would be to provide prices at which units would draw, but I don't think you want to go there.

New units from genuine competitive entrants. For them, their reserve price in the participating auction is important confidential, commercially-sensitive information. As I mentioned we have, I believe, a lot of developers whose intent is to clearly spin-off their product, which is a perfectly reasonable course of action.

But to have their reserve price review prior to their attending the auction seems to me to undermine the competitive procurement process that we have. I would hesitate, before we went too much further.

There may be some areas where we can provide more information. But certainly there are a lot of areas where we're right on that line to address John's question about why a lot of folks might have withdrawn early.

My interpretation of their behavior is precisely to preserve their confidential nature of their reserve price in the auction. Once we've published 120 days prior to the auction with the FERC, of the participants and our need, you can determine that we did not need new capacity above .8 CONE.

These resources, to the extent that they have a reservation price above .8 CONE, logically I think, if I stay until 1 times CONE, people are going to see in aggregate results of my megawatts withdrawing from the auction. The consultants are going to be able to infer my reservation price, and that's going to disadvantage me in any bilateral deals I want to do.

So I think what they did is say look, I know I'm not going to be able to stay until when they need new capacity, which again is reasonable behavior. I don't think it's anti-competitive, but I think it sort of speaks to the idea that there is commercially-sensitive information in the market that we ought to protect.

MR. SPECK: From the state standpoint, I think that there certainly could be a lot more transparency, particularly in the RPM. Just by contrast, for instance, I saw actually filed the report from the auction at FERC, and there's a 45-day period for comment.

It gives all the stakeholders an opportunity to come to FERC to challenge some of the conclusions that were reached, and to have all that aired. There's no such opportunity with regard to RPM that's analogous to that.

I think also in particular, with regard to C-TEL, that is very different. In ISO New England, the local sourcing requirement is a transparent process, and there is an opportunity to test that. That also gets filed at FERC.

So there's an opportunity to test that

determination. I think those are key areas where there is not sufficient transparency in the RPM model, where there is in ISO New England.

DR. BOWRING: I certainly agree that more transparency up to a point is appropriate. More transparency in a couple of things is good. I would agree on the key question.

That does have a substantial impact on market outcomes. The definition of LDA is exactly where those borders are drawn, and all the C-TEL processes could certainly stand some more light and more transparency.

I would not suggest diverging any more detail about offerors. We provide a lot of information. We provide the detailed supply curves. I think we've gone as far as we need to go there. As far as fighting things at FERC, as many people comment, I think that's fine. That helps the process. That's fine.

DR. WOYCHIK: In terms of too much information in the market, I think that's a problem, but Joe and Barbara basically covered that. Something as different as transparency of a market rule and how much they change.

For example, when zones change, those kinds of things are very troublesome for us. That did miss a couple of times. I think we need to somehow get the process to work better and make sure that it's more transparent. In terms of information outcomes, I'm pretty comfortable with the way it is right now.

MR. KELLY: David?

MR. MEAD: I have a couple more questions about the American Forestry proposal, related to the strike price. As I understand it, the strike price could be whatever the marginal cost is of the existing unit and whatever RTO is supplied.

It strikes me that if you have -- if the marginal cost is higher than the strike price, that participating in that market becomes very difficult, at least somewhat difficult.

Do you see that as a problem, and is there an advantage to making the strike price sufficiently high, so that it's higher than the marginal cost of any unit in the control area?

MR. SIPE: I think you're going to be constrained by the fact that you have a curve at PJM. By that I mean you have a theory that posits that there is a value for capacity, that is pegged at some number for a particular unit, and under the theory of an efficient mix on how things ought to run, you've got to compare those two units in order to come up with a reasonable adjustment.

So I think you may be concerned by the curve, but I like the higher heat rate in the New England auction, but you've got to remember that the price of the New England auction is not constrained by the curve.

As was pointed out, the price of the New England auction allows a depreciated unit to get in at lower capital cost. We can drop essentially to the floor even at ICR.

If you did that and PJM auctioned to the curve, you'd be paying people CONE, and to be paying them, allowing them to recover scarcity above the marginal operating cost of your proxy units. I think by definition on the merits that's wrong.

I think you're over-recovering. I think the better design might be to move to the adjustment in PJM, and if you think there's a problem with that issue, to do something with a curve, alternatively if you're truly an appreciated unit and you have a low bid cost and a high operating cost, you will collect more in that CONE payment than you need for your capacity.

There may be some hours in order to get that capacity payment, where you have to operate at a loss. I don't think that's insurmountable, as long as your entire payment doesn't go negative.

But if the theory on which the curve was based is correct, if you're saying it goes negative, you are not inefficient. You are not a unit that ought to be in that market.

There is another unit that should be more efficient, that can operate undercollecting the full capacity payment and the full marginal rent. So that's what we're looking for.

I think the answer in the two pools needs to be different. I think you're pointing to one of the problems of trying to do this efficiently with the demand curve.

But you know, I don't think it's an insurmountable hurdle, for the reasons I just stated. If you truly have a efficient unit, you shouldn't be making money under the demand curve. I think the better design is probably the FCM. But to do the FPO, you don't have to completely redesign the PJM market.

You just have to assume that a unit is going to have some hours that it's going to have to provide energy at a loss. It's resulting in a bigger capacity payment at the end.

MR. MEAD: Do you think in terms of determining for a unit that got a high operating rate, and especially a unit that's got a pretty high outage rate and it knows it, so that it's actually accepted into the market, and it's going to expect that it's going to have to make payments reflecting the difference between LMP and strike pricing, and times when it's going to be out?

Should that cost be allotted to be included in an affiliated offer price?

MR. SIPE: I haven't had time to think through this completely, and my answer may change after I think about it a little bit more. But I think essentially under your curve, the competitive outcome is that people will bid their avoided costs, and that will be adjusted upward to whatever the actual value of that amount of capacity is.

If you treat the demand curve truly as a value function of what this capacity is actually worth in terms of reliability and other things going out on the end, I don't think the fact that the curve has gone down, people are bidding their true avoided cost and the effect of what they ought to be paid for energy and ancillary services.

If that is a value function, that capacity is truly worth less out there, and we should be no more encouraging an efficient unit out there than we should be further up the curve. Where you may have unmitigated bidding and people are clearly at a value above CONE or at CONE and ICR, that's my initial impression.

But the avoided cost calculation is appropriate without trying to roll back in money that you won't make in the energy market because you're inefficient.

MR. MEAD: My thought was that such a dog ought to be pretty far to the right in the quadrant of the supplier. This probably should be among the last resources that you pick. But you can mitigate it so that the offer is lower and get picked, even though it's going to be out on outage much of the time.

I think it probably ought to be delisted. For me, I think the idea that people bid their avoided cost, whatever they expect to make in the energy market is the right principle. I agree that the curve creates complications that need to be thought through. I prefer the FDM side, because it's much more to the heat rate.

Much more attention needs to be paid to a particular unit, because you have the ability to let the capacity price float. So two things are they can be disentangled in some way, but I think it's much more difficult under the curve.

DR. BOWRING: On the narrow question, if you have a badly-performing unit with a high forced outage rate, high avoided costs and no energy revenues, by definition is has a very high offer price. We have units like that. Sometimes they don't clear. Sometimes they're above the demand curve.

It does end up how we expect, the whole issue about the optimum price raises the broader question. You don't need to go to that level of complexity, because what I took to be the answer that Joe was trying to get to in this morning's presentation, simply to have them close to real-time energy, you can get there much more directly without going to a particular hedge price, which could potentially create the issues you've identified.

I think the underlying theory in the PJM market is what capacity is, at least in significant part, the requirement for what you find is the requirement you're going to offer into the data market, a must-offer requirement on I would say a must competitive offer requirement.

Effectively, to call it the market CONE price, I think we've already gotten to the place that the FPO is trying to get to, without having to add a complexity if you want to get closer to real time. That's the general direction.

MR. SHANKER: I think it comes back to the fact that you're coupling the costs. If you want to do that, it's going to cost you something, and it's going to be into the price. If you put it in, one of the elements that Joe would have to evaluate would be the reasonableness of how someone reflects the cost of the call in your office.

It should be part of the negated price, which is not a knowable concept, and there's a lot of theory to support this, although I'm sure there will be differences of opinion on how to place that call.

It's an insurance-type product, because normally they could go out and buy it from a third party, and they show it to Joe and it comes in the bid. That's why I keep saying this is a premium product. There's no reason you can't have it if you want.

I don't know that I'd say it, per se, is complex. It's complex as much as expensive. Find out what it costs. You're in a position where you can make inquiries as to what that kind of product would sell for.

You should take a look at it, because I think you'll be surprised what kind of premiums go with it.

MR. MEAD: I have one more question for Dr. Bowring. During your presentation, you were talking about responding to some of the points made in the Wilson paper. One of the points, as I understand the argument was that there was some generation offered in the Southwest MAC for, I don't know how many RPM auctions. At least one, perhaps a few.

And they included, as I understand it, these were relatively old generators that needed to make some upgrades that could be counted as capital costs. PJM, according to the settlement, permitted a fraction of these costs to be amortized in the offer caps.

But at some point, in the more recent auctions, the same generators elected not to include that premium. In the first auction, at least part of the capacity did not clear, and in the last auctions it did clear.

As I understand the argument, it was not that the generators were violating the settlement, but that provisions of the settlement permitted the exercise of market power because those generators were offering capacity that was higher than what was their actual going-forward cost, at least after the first auction in which the investment was made.

At any rate, my understanding of the argument was not that the generator or generators were violating the settlement, but that the settlement permitted some exercise of market power. Do you accept the third characterization? Do you agree with that conclusion?

DR. BOWRING: I think it's a fair characterization. No, I don't agree with their conclusion. The issue is whether providing the ability to offer in a piece of the investment required to maintain an old unit as a capacity resource as an exercise of market power, I would say it's not.

I would say it's a rational addition to the offer cap. It would called APIO. It can be amortized, depending on the asset, over anywhere from three to fifteen years. What I concluded is we would have a very significant issue if PJM included it.

That provision has permitted investment of literally millions of dollars in order to permit them to comply with the requirements of Maryland and other states which, in my estimation, would not otherwise have been made.

It's not an exercise of market power. I think it's an appropriate incentive. In fact, it's consistent with the kind of incentive that the Wilson paper argues is appropriate for new investors. That is, a multi-year pact. It would make sense. That would permit the initial offer to persist over a longer period of time than one year.

So that's a relatively short answers to a long question. There is one point I think made in the paper about the incremental auction. No one from the outside could have matched that offer from our firm. I can tell you that was not the result of individual units exchanging a high offer for the low offer. That's not in fact what happened.

MR. KELLY: Michael, would you introduce yourself?

MR. ISIMBABI: Michael Isimbabi, Office of Energy and Market Regulation. My question is for Dr. Woychik.

Given the inevitable comparisons between the RPM and the FDM, do you have any specific views on the way the markets are designed with respect to both demand side resources and some aspects of the function for the RPM demand curve, and perhaps the treatment of new entries?

DR. WOYCHIK: Thank you. I'm not sure I quite understand all the question, but let me let you clarify.

MR. ISIMBABI: My understanding is that you participate in these markets?

DR. WOYCHIK: Yes. We participate in both, basically with our industrial group in PJM. Everything seems to be working well for the capacity components of that. It's the related ancillary services and energy payments that are problematic, as I discussed, and for residential as well.

We just had a new contract with Maryland. We provide residential and they actually play that value to the market. It's working very well. It hasn't even started, but we know it's going to work real well.

In the ISO New England situation, there's an average price there. There's internal conflict in the company. On the one hand, if it's for industrial customers who may have loads across the year, that's very good for industrial customers.

For residential loads such as AC load, we would rather have something that's like the PJM auction, which requires five months' performance, and we want to perform in those five months.

Arguably, it might be -- my goal is to work two ways. I had a discussion with Mr. LaPlante about that during the lunch today. It certainly is not conducive always.

It's workable at this point for PJM, but it depends on these other revenue flows. We want to be comparable to generators. Generators get those same kinds of revenue flows. They're not allowed.

In ISO New England, we don't get to play and operate in this market. There's limitations and then change of zones and other rule changes that are not transparent in PJM. So there's a set of issues. I hope that's responsive.

MR. KELLY: Tatyana.

MS. KRAMSKAYA: I wanted to follow up to what Mr. Ethier said, about the relationship between the capacity markets and transition planning. My question is to him, but anyone on the panel can respond as well.

Will the fact that there was no price separation between the taxi zones at the last auction have any long term impact on both transmission planning, and especially siting?

MR. ETHIER: Let me answer it a little differently. The results of the auction, those results are going to affect transmission planning.

Now, what's interesting but not surprising I suppose, when you look at where the resource is located, both generation and demand resources, it was primarily Massachusetts and Connecticut, which is precisely where our load is.

But demand resource, because it makes perfect sense, you've reduced where the demand is. But also the supply is located there. That's what I was getting at when I said that the auction, because we now know three years in advance what resources are going to be there and what resources are not going to be there, will better allow us to play in our transmission system.

The way we look at transmission planning is sort of we identify a year of need. Given all the many, many input assumptions, in what year do you need a new transmission project to prevent you from violating criteria?

In effect, new resources often allow us to push back that year of need, one, two, three or four years, depending on how big the resource was.

That's the dynamic that I think is encouraging. It can allow us to avoid these irreversible investments, and better coordinate between the transmission and generation side.

MR. SHANKER: In the PJM structure, the transmission effectively leads to generation, the planning horizon. This is in the C-TEL violations that principally are reflecting a press separation. There can be differences in marginal costs within the zones.

At the big scale, those are mandated. Upgrades in the transmission plan and they're seeing farther ahead than the RPM procurement. So in the plan will be embedded at the time of the auction, and we get into issues with that, where things are delayed and all those other issues.

But in the plan, there is always going to be a solution for the perceived congestion of a C-TEL violation. So you have an intrinsic bias, as it were, for transmission.

You can only get rid of that if you held the commitment for the transmission fixed at the same time that you held the commitment for the new capacity.

I think one of the working items that we have in the stakeholder process, I believe, is discussions about what assumptions should be made about the location of future generations, within the context of the transmission planning assumptions, that is for generation. That isn't here yet.

That would change that dynamic, but right now essentially the transmission plan leads to generation.

MS. KRAMSKAYA: Just to be clear, for the purposes of transmission planning, how many of the entities are involved in it?

MR. SHANKER: There's a process which Steve argued out, about whether there should be more. They conduct essentially a two zone reliability study, the LVA and the rest of the PJM. They do a one and twenty-five year reliability study. That gives you the C-TEL.

It tells you you have to able to transfer between them. Somebody named Steve Herling has given a definition of what the C-TEL is, which is the limit. If they see a violation, it's a reliability first violation, and it must go into the plan.

That decision is made in advance of the RPM auction, somewhere in that five to seven year kind of horizon is when I think it is on that horizon, the commitment. But it's definitely further out than the three years.

DR. BOWRING: Can I just follow up on that? I don't know if you said this basically or not, but that's been assumed in setting the limits for RPM. You could conceivably be or you are in fact saying you don't need the generation to solve the problem, because you already have the transmission.

So there are two ways of dealing with it. One is to make the lead time the same, which is probably very difficult to do, and the other is to rethink how the assumption is made about what transmission is going to be there. Those are the ways to do it.

MR. SPECK: That's a very critical point. This auction is coming up right now. That's why particularly Maryland is concerned about the auction taking place this week.

There is a transmission line, a trail line that is scheduled to be completed May 30th, 2011, just before the start of that next year. If that's delayed, the PJM reliability people have told us in Maryland that's going to create a reliability problem in Southwest MAC.

We've got to see now and decide now what we can do about that. We are looking at the licensing process and siting process that's going on in three different states, to see whether that's actually going to happen or not.

I'm not willing to pick up that right now, but that's going to be there on May 30th, 2011. That transmission line is going to be up and running May 30th, 2011. But we have no locational signals now. Southwest MAC is not a separate zone.

Therefore, Maryland is going to have to do something separate and apart from RPM essentially, because if we make the judgment that we're going to need that generation for reliability purposes in 2011 because we can't count on that transmission line, we're going to have to make a decision about that soon, very, very soon.

MR. SHANKER: Just to clarify that, the line is assumed to be in the plan for the auction. That's why it's not separate. That's why it's not showing up as a constraint.

So the concern is that thought was two deals we're talking about here. The concern is if it's not there, we won't be procuring in a locational fashion and sending the signal. There are a lot of people that would believe that it may not make it in time. I think that's a pretty good bet.

DR. BOWRING: One more point about the locational signal. Even in cases when There's not a differential price across LVAs, and there's not a locational signal, what you need to do is go to the ancillary services. When you do that, there's a very strong locational signal. You need to recall all the aspects of the revenue.

MR. KELLY: I'd like to ask Mr. Rismiller a question here. In your prepared remarks, you advised the Commission, FERC, not your own Commission, to be careful not to dampen the price signals for AMI.

I'd like to hear a little bit more about that. Is there something we're doing now that dampens those signals, or is it the very existence of the capacity markets or something about their design, or is that out of the capacity market context. If you could elaborate, I'd appreciate it.

MR. RISMILLER: Yes. I think it's hard for state regulators to develop the cost benefit ratio to support large across-the-board efforts for advanced metering infrastructure.

One of the benefits, one of the things that we feel is a benefit on the benefit side is avoidance of the capacity costs. So that needs to be considered in these wholesale market designs, because it's the demand response that comes from exposure of customers to a wholesale price, and their ability to respond to that price that puts the price elasticity into the function that you're looking for. That would be the context for my remarks.

MR. KELLY: Could I conclude from that then that if there were a utility area, that we're going to receive a capacity payment requirement, irrespective of whether they adopted AMI.

That would be a disincentive, or is it that if AMI is adopted, the fact that demand is price-responsive is a substitute for that area's need for new capacity, that in some sense meets its capacity obligations, and we'd have to make an additional payment at the capacity margin?

MR. RISMILLER: That's one aspect of it. The other aspect of it is, and I'm not sure that the existing capacity market designs have this element, but some that have been proposed certainly have this aspect to them, that they do have the effect of dampening the energy and ancillary services price, and moving recovery of costs into the capacity side.

That's something that is not reflected in that spot market price signal, that is the calculus for generating benefits for investment in the advanced metering.

MR. KELLY: We're drawing to a close. I have just maybe a comment and a question for two people. The comment is I tried for this panel to do what I did for the last panel, to see where the sentiments were in terms of PJM and ISO New England, work within the existing framework.

If there need to be some tweaks, some changes, versus adopt a wholly new model, perhaps like the American Forest or Portland, I found it harder on this panel than the previous panel to do that.

But I came up with that. Anybody can quarrel with these categorizations. Four of you say work within the existing framework to make change. One for American Forest, Mr. Sipe; one for Portland Cement. One, and I put Mr. Speck in this category.

The question is as to whether you agree with this changing PJM to look more like New England is the way I took your remarks, and then two who dealt primarily with other issues that didn't exactly address my categories.

So I wanted to ask Mr. Speck to comment on just whether you would impose some perhaps moderately radical change on PJM's design, to look more like New England. I wanted to ask Mr. Elsea if you do business in both those areas, are you happy with both areas.

I thought your remarks were very positive and supportive of capacity markets. But I couldn't tell if you were 100 percent happy with them, if you would tweak them or indeed if you want to redesign them along the lines say that Mr. Sipe supports. I'll start with Mr. Speck.

MR. SPECK: There are certainly a number of elements of the SEM that I think are working much better than comparable elements in the RPM. One is, for instance, the energy and ancillary services offset in PJM. That seems not to be working well at all.

For one thing, it's not nearly contemporaneous. It's six years before the actual performance period. I think it will work much better in New England. The FPO model is not that different, as Mr. LaPlante said, from the PER adjustment in New England.

I think there at least some relationship between those two. I agree with Don that it would be much more difficult, though, to impose the FPO process on the demand curve that exists in RPM, and therefore it certainly has taken more tweaking and more than just tweaking, I think, to be able to make that work.

There are a number of other elements of the FCM that seem to be working better. Demand response, energy efficiency, they are much better able to participate. That's evidence of the first auction in New England pretty clearly.

There are a lot of problems, I think, in the demand curve itself. That does not give, I think, the same level of competition that you've achieved in New England.

I guess finally, as also has been mentioned by others as well, the descending clock auction, I think, does have some real benefits over the type of auction that's conducted in PJM. I think there are elements of the New England model that are working pretty well and it ought to be looked at as possible models.

I would categorize my view and my client's view in Maryland as if we're going to require more than just simple tweaking, there may be a little more change that's required than that, but not necessarily a full-blown blow it up and start over again.

MR. KELLY: Thank you. Mr. Elsea?

MR. ELSEA: I can't speak to ISO New England, but I've compared PJM to MISO, and what we're doing behind both. Not a lot behind MISO, and we're starting to do more behind PJM.

Our distributed generation component, just that two megawatt unit, is kind of anecdotal. We looked at facilities behind the PJM footprint, at what's the most optimal facility. We looked at ERCOT and Cal ISO, but really didn't look at MISO.

I think the RPM provides az good price signal for demand response, from a distributed generation standpoint. If the forward markets could move out beyond where they are now, my suggestion would be to go beyond the three years.

When we did our cost-benefit analysis, we had a idle asset. It was a depreciated asset, so it's just a matter of relocating that behind someplace in PJM. But to install maybe a new DG, you know, that has time horizons but tight to make the returns on investment look good.

Then lastly, from my experience, I've dealt with a joint action agency in Ohio, AMP Ohio. You may be aware several years go they installed upwards of 70 DG. That's around the state, behind the municipalities.

Because of the 1999 or 2000 price volatility in the market, and of course that volatility we haven't experienced that since then to that degree. But they wanted to have that island in the ground.

That investment for the most part has been idle. Now I'm convinced that those units that are behind PJM and MISO will be utilized.

MR. KELLY: Thank you very much. It's almost five minutes after five by my watch, and I know some of you have planes from National Airport and Washington, D.C. rush hour traffic to negotiate to get there. I think we should break off now.

Again, thanks very much for your participation.

(Whereupon, at 5:05 p.m., the meeting was adjourned.)