BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Number:

RELIABILITY PRICING MODEL; : EL05-148-000

PJM INTERCONNECTION, LLC : ER06-456-000

: EL05-145-000

: ER06-309-000

: ER06-406-000

: EL055-50-000

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Commission Meeting Room

Federal Energy Regulatory

Commission

888 First Street, N.E.

Washington, D.C.

Friday, February 3, 2006

The above-entitled matter came on for technical conference, pursuant to notice, at 10:00 a.m., Joseph T. Kelliher, Chairman, presiding.

APPEARANCES:

JOSEPH KELLIHER, COMMISSION CHAIRMAN

SUEDEEN G. KELLY, Commissioner

NORA JEAN BROWNELL, Commissioner

P R O C E E D I N G S

(10:00 a.m.)

CHAIRMAN KELLIHER: Good morning. We're here this morning to discuss matters raised by the Reliability Pricing Model, or RPM proposal, filed by PJM Interconnection in Dockets No. ER04-1410-000 and EL05-148-000 on August 31, 2005. As we stated in our notice issued on December 8th announcing this Technical Conference, we're here today so that the Commission can hear arguments and gather information to aid us in making our decision on this proposal.

Specifically, we'll hear arguments on three major topics. First, whether the current capacity obligation construct within PJM's market design provides for just and reasonable wholesale power prices in the PJM footprint, at levels that provide adequate assurance that necessary resources will be provided to assure reliability, or whether changes must be made to that capacity construct.

Second, whether PJM's RPM proposal would provide for just and reasonable wholesale power prices in the PJM footprint, at levels that provide adequate assurance that necessary resources will be provided to assure reliability, or whether changes must be made to the proposal to meet those goals.

And third, whether an alternative approach to RPM is necessary to ensure just and reasonable wholesale power prices in the PJM footprint.

In a nutshell, we're here today to determine whether there is a problem, and to identify solutions. If there's a party in today's proceeding who disagrees that there is a problem under the status quo, this is your opportunity to make a convincing argument that the status quo is working and is just and reasonable.

According to PJM, the current capacity construct has serious shortcomings that have resulted in seeing very few generation additions, but high rates of generation retirements in some of the same areas of PJM region where load is growing fastest.

As a result, PJM states that the State of New Jersey -- my home State I have to point out -- faces violations of reliability criteria in each of the next four years. Other parts of the eastern PJM region, including the Baltimore Washington area, and DelMarVa, are trending towards similar violations due to high load growth and comparatively low generation additions.

PJM will open our conference with a factual overview of their current infrastructure, and this will provide us with some basic facts from which we can continue our discussions.

I'd like to note that yesterday the Commission issued a supplemental notice to add a few pending dockets that raise issues that are potentially related to issues that have been raised in the PJM proceeding. In particular, Docket No. EL06-50 is AEP's recently filed petition for declaratory order regarding proposed incentive transmission rates for its AEP Interstate project. The 765 kV line, which it proposes to build from West to East across PJM. Because of the potential importance of any such large project to the region, it's likely that the proposal may be mentioned during the discussion.

I reiterate that the purpose of this conference is to discuss the merits of the RPM and not the merits of the proceedings included in the Supplemental Notice.

Anyah Dembling, from the Office of External Affairs, will be keeping time to ensure presenter's remarks do not extend past their allotted time, and we will strictly adhere to the time limits. This is to ensure fairness. Each of the parties will have an equal opportunity to present their arguments to the Commission. This is also to ensure that there is sufficient time at the end of the prepared remarks to discuss these issues.

You will notice the yellow light in the clock in the well; that light is your warning that you have one minute remaining and you should begin concluding your remarks. When the light turns red, that is an indication that your time is up, and you must conclude your remarks so we can hear from the next person.

I'd like to introduce our two staff members assisting us today at the table; Anna Cochrane is the Director of the Division of Tariffs and Market Development, David Mead is an economist in our Policy Division. Dick O'Neil is our Chief Economist, and Tatyana Kramskaya is an Energy Industry Analyst in the East Division, part of our Russian brigade here at the Commission.

Hearing Room 1 is designated as the overflow room for this proceeding. According to our schedule, we will break for lunch at 1 o'clock and plan to finish by 5 o'clock today. And I appreciate your attention and look forward to hearing your arguments. Thank you very much.

Colleagues, do you have any comments you'd like to make before we start?

(No response.)

Okay, why don't we call up the first panel.

MS. ZIBELMAN: Good morning, Commissioners.

My name is Audrey Zibelman. I'm the Executive Vice-President and Chief Operating Officer for PJM. I'm here today with Andy Ott who is our Vice President of Market Services at PJM.

Today I'm going to be providing the Commission with an overview of the reliability concerns the led the PJM to look at developing and changing its current capacity market, and the reliability pricing model. Andy will be providing around the model, and both of us will be able to answer any questions, here to answer any questions you might have.

I'd also like to note that we have Steve Hurling in our audience, who's the Vice President of Planning at PJM, and he's also here to answer any questions you might have, particularly about those issues.

I'd like to start by thanking the Commission for hosting this technical conference. From our perspective, this is the next step in what has been a five year process for us to solve a very challenging issue, and the issue is this: PJM's markets have been in place for eight years. The markets are working well. However, like other markets, we continue to need to evolve them based on the information we receive as well as changing needs.

Our challenges right now and going into the future is looking at how do we attract the right level and right type of transmission investment, demand investment, as well as generation investment to make sure that we have a secure and reliable grid as well as an economically efficient market.

PJM's mission, as you well know, is to ensure reliability in system operations as well as to ensure competitive markets. We can't do that unless the three legs of the stool that we're trying to build are all sound.

In terms of that, as we look at the RPM model, I want to take a note that the RPM model, though as proposed as PJM's model, has been informed by a very good, strong process. We've had the benefit of advice and suggestions from our members as well as our States, and we think that the model that we have proposed before you today is well designed to solve the very important capacity needs we see in the future.

We can turn to the next slide.

A I've mentioned, from PJM's perspective, this is a three-legged stool. The first leg of the stool is a very strong and robust energy market. In terms of that, our energy markets have worked well. A number of studies were performed last year to look at the effects of competition on consumer prices within the U.S. In particular, in a study performed by ESAI showed as a result of PJM's integrations and the growth of its markets we were saving consumers the approximate amount of $500 million a year as a result of the integrations.

The ESAI study was really complemented with the studies performed by CERA as well as Global Energy, which collective, together in the case of CERA, noted that competition was saving consumers $34 billion a year; and in the case of Global Energy, in the area of $15 billion since 1977.

The point, Commission is that they are going well, but they continued to evolve. One of the issues -- and if we can go to the next slide -- that PJM has been focusing on is the issue of demand response. We think in order for the markets to work well, to provide the efficiency they need, supply and demand need to be complementary, they need to operate on the same level.

One of the things that we've been working in the last years, with our encouragement as well as the encouragement of our States and our members is, how do we increase the penetration of demand response in competitive wholesale markets? We've had a lot of initiatives on that endeavor, a lot of focus, and I'm pleased to say that we're starting to see very good results.

In this slide, you'll see we've had a huge amount of increased transaction on demand response in the PJM's markets in 2005. The other point is that we're not done. As you'll see in the last slide, last year, working with our members, we've had an increased commitment to take a look at making sure that we were not just focused on supply, but we're also looking at demand.

And one of the commitments that PJM made is we wanted to make sure that every source of revenues that a generator might have in our market could be complemented by a similar source for a demand responder. And we've been making significant inroads in that way.

One of the things that we're looking at is how do you get demand response in to a capacity market? In our capacity markets today they cannot compete; there's no place for them.

One of the things we heard from demand responders is just like generators. In order to make significant capital investments, in order to provide the next level of demand response, they need to have a fairly certain revenue stream; they need to know what the forward prices are so that their investments are not wiped out by a cool summer.

One of the things that we're looking to do is to develop a demand response market that will work in conjunction with the RPM market so that we can have these type of long-term capacity investments in demand response products so we can get to the next level of that demand equation. But we need the RPM to complete that.

The next point is, what's the second leg of the stool, and as you well know, it's transmission. Last year I was in front of this Commission and we talked a lot about the fact that PJM's planning process, while historically meeting the needs of the market, needed to be stepped up to look at the forward needs we'd need. In particular, with the expanded market, we need the new types of transmission infrastructure, the type of backbone facilities that everyone in the country is talking about is needed for the future of the U.S.

The second thing we needed is we needed to include in our transmission process a longer-term look. Looking at five years ahead makes sense when most of the generation that we're talking about was peaking-type generation, gas-fired generation. Now we're starting to look at central station power plants, coal plants, nuclear plants, as well as a much-expanded footprint; so we need a 10 and 15 year planning process.

In addition, the type of transmission investments we're talking about are much more expensive, and our transmission owners are telling us they need more pricing signals so they can put their plans in place and respond accordingly.

The other piece that we need is a better economic signal, and so in our planning process we're working with our members to include not just reliability, but economic efficiency as a part of the criteria that we will look for transmission. We've made a lot of inroads in that area, and I'm really pleased to announced that we anticipate, as PJM, that in 2006 we will have before you the ability to file a 15-year transmission plan not just a 5-year and that we will be looking at economic efficiency.

I also will note, as the Commission I know has no doubt noted, that some of this discussion about the need for more backbone facilities has already had its effect. We were very pleased to see the AEP filing this week, and we will work with AEP and others to take a look at how do we get those backbone facilities built and how do we do it in a way that doesn't create the delays that we've seen for other facilities in our history.

But nonetheless, Commission, that's going to take time. And as you look on this slide, our problem is what we're looking at as reliability concerns in the immediate future. As we looked at the supply and demand equation within the PJM footprint, we saw during the periods of 2006 to 2010 we had areas particularly in the eastern region where in fact the supply and demand equation would no longer work, and that we are going to fail reliability criteria; and that we didn't have the transfer capability in the existing transmission system to meet it. And what's more is the level of transmission investment and the type of transmission investment that could be required to meet those reliability criteria would take more time than we had to really get it done.

If you can turn to the next slide, I can show you a bit of the difference of what's happened. Historically, PJM has looked at shorter haul transmission investments, upgrades to existing systems, and the cost of the transmission has been in the 100 to 150. As we've reported to you many times in the past, since PJM started transmission planning, we've had roughly $2 billion of investment. But systems such as AEP is looking at will actually double or even triple the nature of investment we've heretofore had.

And so we can't look at this level of transmission investment without solving the other side of the equation, and that's what we continued to dialogue on last year. A lot of our members in our States continue to say to us: You can't solve the generation issue in isolation; you need to look at the transmission issue.

We agree. They have to be part of the same stool we're building. By the same token, we can't just look at the transmission issue and not solve the generation issue; and we need to figure out what do we need to do to attract the type of generation investment that we're going to need in the future to satisfy the reliability concerns and create that efficient marketplace.

If we turn to the next slide, one of the issues that PJM had to deal with is the fact that not only were we seeing load increases in our region; we're also seeing increased generation retirements, moreso than we've ever seen in the past.

In 2004, we had 4,000 megawatts of generation retire, and the map shows you the area where they retired. In 2005, we had another 700 megawatts. In 2007, we're anticipating another 700 megawatts.

One of the things we've heard from the generators is the main reason that they're retiring, for a lot of them, is economics. They simply are not getting the revenues from the capacity market that they need to stay on line.

The other problem we have, Commission, is simply looking at the age of our generation infrastructure.

If you take a look at the next slide, we've done an analysis, and we often talk about the fact that we have an aging infrastructure in the electricity industry in the U.S. And most of the time I think when people talk about that they're thinking about the transmission infrastructure, but it's equally true in the generation infrastructure. And if we look at the generators in our footprint, you'll see a vast majority of them are over 20 years of age, and a significant amount are over 30 years in age.

We need to start thinking about what's going on with this generation; is it going to remain in place, how do we attract new generations with the new technology and the new capabilities into the marketplace, and that's the problem we're seeking to solve.

In looking at that, we came down to, there are two major issues. One is transparency. What we heard from investors in terms of looking at retaining their generation on line, or even in putting in new generation, is a need to have the price transparency. They need not to only know the price today but the value of the generation going out in the future. It's only with that that we can expect competitive investors to invest in this generation sector, since it's not a regulated sector, with the knowledge of what their returns might be; and that helps also trim price volatility and solves another host of problems, as Andy will talk about.

The other piece is certainty. They need regulatory certainty, they need the rules of the game, et cetera. This is a piece I think we've all talked about for a long time in terms of market design, and they need to know the locational value. Just like any other type of investment, the value of generation will change in location and will depend on the fact of whether or not you have a load pocket where there is significant congestion and there's no way to get the power there. That's what we needed to design in terms of resolving our capacity market.

With that, Commission, we've given a lot of thought as to today and the help that we need. As I've said, we've had a lot of discussion, a lot of debate, and there have been a lot of changes to the RPM model as a result of that. However, as we thought about it, looking forward we think that the problem before us is there are some very clear policy issues that need to be addressed as well as some factual issues. And what we would ask is for you to give us guidance on some of these very important policy issues; and in my pre-filed statements I've listed them, and I'll just go through them briefly.

First is the very important policy issues, whether the Commission believes that a capacity obligation construct remains necessary and a just and reasonable element of the market designed for the PJM region.

The second is whether the capacity construct that we use in PJM should include a locational element, and whether that is of value.

The third is whether the capacity obligation should include forward determinations of the specific obligations and commitments to be made to facilitate both new entry, the ability to provide the price signals for both generators and demand responders and transmission investors, and to promote reliability because of more certainty and planning.

The fourth is the very important question, is whether a downward-sloping demand curve, which is in principle, will help solve some of the volatility issues and provide again greater certainty, and reduce the risks and ultimately the price of capacity in our region.

And the last issue is whether the capacity construct should include mitigation rules, which will help, include offer caps so that market power tests could be accomplished.

With that, Commission, with that type of guidance on these principles, many of which I think you've solved in other dockets, we think we can move on and start dealing with very specific factual issues that we have before us to solve this problem.

Again, we've been at this five years, I think we've evolved this to a point where the issues are crystallized; we believe the policy guidance of this Commission will be invaluable in getting us to the next point; and most importantly, we believe it's an issue that needs to be resolved.

And I thank you for your attention, and I'll turn this over to my colleague, Mr. Ott.

MR. OTT: Thank you, Audrey, and thank you, Commissioners for allowing me the opportunity to speak on the very important issue of capacity market reform.

A well designed capacity market can provide forward transparent information to incent investment. The key is to make sure that the investment incentive that is sent is consistent with reliability requirements in the PJM market.

As Audrey had said, we have experienced retirements; and retirements in and of themselves are not necessarily an indication of market failure; but when the retirement occurs in an area where the generation is needed for reliability, so when a retirement request comes in and PJM has to intervene and require the unit to stay for reliability, that's indicative of a problem.

As Audrey explained in her statement, the stakeholders are presently working on transmission planning process to support long-term planning and building transmission infrastructure. However, transmission expansion alone, as we said, will not be enough.

The capacity design must have a forward mechanism to show all stakeholders what generation is needed in what areas, and what demand response opportunities exist in heavily constrained areas. To promote what I'll call competitive solutions to the ongoing reliability problems.

The mechanisms to evaluate the ongoing reliability problems must be transparent; they must provide information that is actionable to the stakeholders, so that these incentives can result in tangible benefits and tangible response.

I'd now like to turn and discuss with you the fundamental features of the reliability pricing model, and describe how they will directly address the challenges that we've described so far in our discussion.

Our current capacity market again, as we said, does not properly value capacity that's needed to address local constraints, nor has it provided a price certainty needed to sustain the maintenance of current plants and the investment in new plants.

So the three fundamental design features that I'd like to talk about are, the first is the four year forward commitment. The second is locational capacity pricing, and the third is a variable resource requirement. Each of these are fundamental policy decisions to address how capacity market design features are going to address reliability requirements in an ongoing process.

I turn to the four year forward commitment. The lack of a commitment in the reliability planning process has created uncertainty in reliability planning in the PJM region. We've seen situations where generation retirements were announced with short notice; therefore, the solutions that are available to PJM are very limited. They may in fact be, the only solution at that point is to try to retain the generator through some sort of RMR contract or generation deactivation charge.

The lack of this forward commitment again does not allow all participants to see the problem coming, and take actionable response to it. Some have argued that a forward commitment should be voluntary; in other words, we should not have a mandatory forward commitment into the future. And while that looks attractive, the point is if only a portion of the load needs to come in and show what their forward commitment is, then you may have between 50-80 percent of the load actually showing up. When you do the analysis, you don't actually see the transmission problems because all the load has to actually be there to be served.

So a voluntary commitment into the future really isn't going to directly address these issues. You really need to see the entire amount of load with a long term plan in order to adequately resolve these issues.

However, that being said, the RPM does include the ability on a four-year forward basis for a demand response to offer-in and say, instead of electing to pay the capacity payments, to actually elect to curtail. And that is a form of voluntary forward commitment.

Essentially what the demand response can say at that point is, "I'd rather not pay above a certain price, and I'd rather elect to put in infrastructure to allow myself to exit system during these times of high demand." So that in itself creates an embedded voluntary forward commitment in the process. So we don't have to make a choice, is the commitment voluntary or not? We can let participants make that choice, but we must require them to make that choice far enough ahead to allow reliability to be served.

Again, as we talk about forward commitments, from some we've heard four years, from some we've heard three, we've heard one, we've heard fifteen. The real issue that you need to address here on the four year forward commitment is, how far ahead must we create this commitment and these transparent signals to allow new entry to reasonably compete to solve the problems. Because as we all know the competition by new entry resolves a lot of the issues related to market power, market structure. It also provides the strong incentive for ongoing, sustained investment.

So as we look forward in time, and we debate, should the commitment between three years versus four, I'm not going to sit in front of you and say it must be four; but the key point here is it must be forward, and it must be forward far enough in advance to allow actionable response to take place.

If we move on and talk about locational constraints, the absence of locational pricing, again, has created a fundamental inconsistency between capacity pricing and reliability pricing. Many years ago I sat at this table discussing locational energy pricing and how the concept of having the reliability constraints that are required to be honored in security-constrained economic dispatch must be properly reflected in the pricing so that all stakeholders who are responding to those price become partners, and maintain the reliability of the system.

What we have actually seen in practice in our markets is that the response to those price signals that are consistent with reliability requirements is much faster, is much more efficient than any administrative structure you could set forth in dealing with locational problems.

So as we look towards a capacity market that will take us well into the future, we need to address the fundamental physical issues that exist on a transmission system, and all potential solutions need to see and face those signals.

Again, as we look at locational signals to create transparent price, one discusses, what about some of the load in those areas that will actually see those prices and need to pay them?

Again, the opportunity for forward hedging and protection is there.  In the reliability pricing model we include a capacity transfer rate mechanism that allows the load in these constrained areas to have transfer rights, if you will; so they see only a portion of their load would actually be exposed to high prices because they have a hedging mechanism.

When you create such a forward price signal that is sensitive to location, the load in that area will see on a forward basis that they have this problem and will take certain steps to do the hedging.

The fact that they respond and take those hedging steps creates long term bilateral contracts. The long term bilateral contracts then come in as the solution to the problem, therefore allowing the market to resolve these issues rather than regulatory intervention or RMR contracts.

Again,l the locational pricing provides direct integration of the capacity auction with the transmission planning process. The fact that in the RPM model we don't create a static set of locational constraints that are not based in physical and engineering reality. These constraints actually come directly from the PJM regional transmission on a four year forward basis; so you actually see fundamental consistency between the transmission plan and the reliability needs of generation and demand.

If I then now could move on to variable resource requirements. This is probably one of the more controversial policy decisions in the RPM model. One thing I would like to point out is if you talk about demand curves or variable resource requirement curves, depending on the terminology that you like to use, a demand curve can be as simple as just setting a price cap and saying that you have, for capacity, an overall price cap of two times the cost of new entry or a fixed dollar amount. And then you can have a price floor in our case today; our price floor is zero, but you could also have one.

That is a demand curve. That's essentially saying there is a scarcity price or there is a price that occurs when the market does not clear. Again, the VRR mechanism creates a demand curve that creates the most economically-efficient result. It allows the penalty price, if you will, to be calculated based on the amount of available capacity. Such an entity who does not meet their requirements would pay essentially the market rate as opposed to administratively determined rate, based on the offers that were received.

The demand curve addresses some other fundamental issues that play capacity markets. It reduces market power concerns by providing again these implicit price caps as a function of the resources available. It reduces capacity price volatility.

As you had seen in PJM's rather lengthy filing on this that Professor Hobbs had put forth, an immense amount of analysis that showed how the capacity price volatility reduction brought by a sloped demand curve lowers the risk to generators and results in lower forward capital requirements and more investment in generation. These dampened capacity price cycles essentially provide the forward certainty that is needed for forward investment and for the investor to have confidence in the market.

So I'd like to summarize. Essentially we're called on to make fundamental choices as we talk about the capacity market reform. One of the first fundamental choices is, do we have long-term or short-term commitment for reliability? And again, let me stress, this is not just long term or short-term analysis that tells you how much capacity you need into the future, but it's actually requiring commitment on a forward basis so that all entities have an equal chance to satisfy that commitment, and we don't have any entities who can wait until the last minute and lean on the system.

Again, if entities want to voluntarily get out of that forward commitment, they can submit demand response-type mechanisms.

The next fundamental choice is, should the price be consistent with reliability requirements or inconsistent with reliability requirements? And again, I think the answer is very clear. And I think we've seen evidence I PJM's market and elsewhere that having consistency between reliability requirements and pricing is fundamental.

We can make a choice between a reliability must-run mechanism or a competitive auction mechanism in order to resolve these issues of generation that's required for reliability.

Again, I'll assert that having a transparent price where everyone assumes that price allows direct competent and will now allow reliability must-run contracts to survive for a long period of time. We also have the question of predictability in price versus volatility or unpredictability in price. Again, the key here is as we look forward, and we're looking for investment signals, the investors must have confidence that the prices that they are going to see are realistic and make sense from a perspective of reliability. And having that predictability in pricing is fundamental to having the market resolve the issues.

Again, the advantages of RPM are numerous. It's forward-looking, it provides the ability, direct competition by new entry, and when I talk about new entry, we're not only talking about new entrant generation, we're talking about new entrant demand response that can invest on a forward basis to make that voluntary choice, as to whether they'll create curtailment mechanisms or not. You also have the ability for transmission to directly compete in the RPM auction to bid a price difference between a constrained location and unconstrained location, and build the transmission infrastructure to cover that import capability that they offer.

Another advantage of RPM is you have accurate and transparent price signals. When I'm talking about accuracy, we're talking about, are the prices consistent with what is needed. Today we see inconsistency. We put a price of capacity out, the generator reacts to that price by retiring; we say "Never mind what the price said, you must stay on line for a period of time." That is an inconsistent signal that creates uncertainty and creates a lack of confidence that the market actually will pay what is needed.

So accurate signals are important; transparent signals are important. Obviously you could solve these problems with RMR contracts, but they are not transparent and they do not allow direct competition.

Another advantage is the integration, the full integration with the regional planning process. The RPM directly addresses the issue of how does the capacity model on a going-forward basis interact with the transmission planning process.

And last is the overall cost to consumers. The various mechanisms in RPM create the least-cost solution, in a transparent way, to meeting the reliability requirements into the future.

Again, I appreciate the opportunity to discuss these critical issues and would welcome your questions.

CHAIRMAN KELLIHER: Thank you.

It would be great to stay somewhat on time. We should ask some questions, but I think we should be somewhat limited in our questions, but this is an important way to start the conference.

Let me ask a few questions and turn to my colleagues.

But you would argue certainly that under the status quo, there's a problem? That is requires some Commission action; the problem won't solve itself; and that a solution isn't just a generation solution but transmission and demand response.

But don't you acknowledge that RTEP, I believe in your statement you acknowledge RTEP has to be reformed for a transmission solution to actually work, or would you argue that RPM implements a transmission solution so the problem is under the status quo.

I had a hard time understanding how would the AEP project compete in RPM, the transmission project compete in RPM effectively. Is it, for the transmission solution to be a real one, is it RPM plus RTEP reform? To try to have as many acronyms in one question as possible.

(Laughter)

MS. ZIBELMAN: I'll start, and I'll let Andy Ott -- yes, to the last question.

CHAIRMAN KELLIHER: Okay.

MS. ZIBELMAN: We see this, as again, you can't do it on a loan, and we heard that loud and clear last year, and we agree. And then the RTEP. It has to process. It needs to include a 10 and 15 year look and needs to include economic efficiency criteria, moreso than we've had before, and we're working hard to get there.

But the transmission solutions that we need are not also going to complete the picture. We also need to have a complementary capacity, market design that allows, with the right type of transmission solutions, if they're near-term solutions, to participate, but also make sure that we have the generation investment.

As the Commission well knows, we can't run the system alone on transmission; we need to have generation. And sometimes we need to have generation in particular places to make sure the system works well; so the two have to work in concert.

CHAIRMAN KELLIHER: But is your argument that RPM really is the solution -- RPM would implement the generation solution or partially implement the transmission solution, partially implement demand response solution?

MS. ZIBELMAN: That's great. We think that RPM can solve the generation and demand solution and partially solve the transmission solution. We need the expanded RTEP process to solve the rest of the transmission issues.

MR. OTT: Of I can put it in this manner. For instance, the AEP line would come in in 2014. The way the RPM structure would work is it would actually see that line coming in in 2014, and that information will actually be included in the forward auction.

So as the RPM would roll out, four years ahead, you would actually see the transmission infrastructure that are coming in the planning process as part of that. So the capacity pricing ones then would be integrated with the results of the planning process on a forward-looking basis. See, today, we really don't have that consistency; you're not seeing on a forward basis -- for instance, you may see a retirement coming in to the future four years from now because of an environmental retrofit. Today there's no way to see that information and there's no way to balance those choices.

On a long haul, long-term transmission line, it would integrate directly in. On a shorter-term transmission upgrade, you'd see a choice -- and you'd actually see that revealed that transparently in the pricing, and that would show the interaction between the planning process.

For demand response, if you think about it, demand response, we've solve the energy component revenue stream for demand response. We just recently put in the ancillary service component revenue stream for demand response.

The capacity component today is really just to say I'm going to avoid a payment; but the business model, to actually have long term investment and demand response to show a forward price and say if you actually commit to that you'll see that price and you can take that to the bank, essentially, and actually use it to invest That's the piece of the demand response that fits.

CHAIRMAN KELLIHER: Now under the status quo, your RMR costs are -- what are your RMR costs currently and where are those costs?

MS. ZIBELMAN: Currently, when we have an RMR contract, and you can add to this, is a cost-plus contract that we will negotiate when people announce a retirement; but under the rules of this Commission, even we can ask them to stay on line, ultimately it's the generator's decision whether even under an RMR contract they want to stay.

So it's a partial solution but not a total solution.

CHAIRMAN KELLIHER: What's the current cost level, say on an annual basis, of your RMR?

MS. ZIBELMAN: We can get that to you.

MR. OTT: It's mostly in the New Jersey area that we're seeing the RMR contracts, but I don't know the dollar amount at this point.

CHAIRMAN KELLIHER: Well, would you argue that if RPM has not adopted, those costs will tend to increase and geographically spread right on --

MR. OTT: Essentially you see in the RTEP results that are looking out into the future, you are seeing of course a very distinct problem in the New Jersey area, but there are potential other problems that have also, you know obviously in the Baltimore-Washington area and some other areas, as time goes on you're going to see these same issues.

You talk about, if you look at the generation infrastructure issues, there are a fairly significant amount of generation that over time is going to require retrofit for, making economic choices to retrofit for emissions control.

If we continue with this same model we have today we're going to see those happen on a near-term basis as we March on in time; you're not going to see them coming. An RPM model will actually show those costs of that retrofit on a forward basis. You can actually see into the future when I put those retrofits on, here's what it's going to cost. Then you can have a balanced solution; you can say now somebody else can see that cost on a forward basis and compete with it, rather than wait until the year before it needs to happen and say now what am I going to do? I have no solution because I haven't seen the forward information.

So the key here is as we go forward in time, the fact is a lot of these plants are going to need expensive retrofit. There's no way today to compare, are those the right solutions or is there another solution? And really, that's the key of what we need to address.

MS. ZIBELMAN: To just add to that, the other piece that we're dealing with is this, is that as we're looking at the generators that are retiring, and if we have an increased level of retirements because the generators can't simply afford to stay on line, because they're looking at the revenue issues, in their own revenues and economics, the challenge we have is that the type of transmission investment we're looking at is not simple investment; it's 500 kV, different lines, it's 230 kV lines; the areas you know that we operate in are heavily congested.

So the problem we have, and even in looking at the AEP investment, just saying that, and having an entity say they want to build a line doesn't necessarily solve our issue, because the type of investment we're talking about, the environmental issues, the siting issues, the cost recovery issues that have hampered a lot of transmission investment in the U.S. continue to exist.

So solving all of those issues will need to occur, and we simply don't think that they're going to be solved in the type of time frame that we need to solve, as well the capacity solution, and that we can continue, as Andy said, to exacerbate the problem, because we won't have the pricing signals necessary for people to either stay on line or make investments that they need.

CHAIRMAN KELLIHER: I have two quick questions that I think lend themselves to quick answers, and then I'll turn to my colleagues.

One is retirements; you've identified retirements as a problem but you haven't suggested that you think PJM's approval should be necessary before retirement is permitted. Right now retirement occurs after notification, but the PJM's approval is certainly not necessary for retirement.

You're not arguing to change that?

MS. ZIBELMAN: With the exception, we have limits in terms of black start units that require a longer notice period, but they have to -- we have a process in place that allows for notification, and if we need it for reliability, we'll negotiate a must-run contract. But in the end, it's ultimately the generator's decision.

CHAIRMAN KELLIHER: And the other, last question I had was, some capacity constructs have been criticized as really designed more to keep existing generators running rather than encouraging entry. Your proposal seems designed really to encourage entry.

MR. OTT: Right. That's the real key, is the point is there have been arguments, very passionate arguments that you can reform the capacity construct at a locational component but keep it on the same short-term basis that we have today. And I will agree that if you had a short-term capacity market like that, that just put some location -- that really just creates a mechanism to allow existing generation to remain.

The key is you need a forward pricing signal with forward commitment requirements to actually allow the direct competition by the new entry. And that kind of construct, with that forward auction-type transparency is really the key to it, because we don't want to just pay, you know, throw good money after bad. You actually want to see that price signal result in some actionable response, and that's really the key here, is that the forward commitment component coupled with the locational components are absolutely critical to make this construct -- in other words, this is not a Band-Aid; this is a solution that will take us into the future.

As time goes on, of course, certain areas may have very low capacity prices, as I showed in my example of the RPM prices; which essentially mean capacity really isn't important in those areas; and that would allow the capacity market to be very low priced or even zero in those areas. But in the areas you need it, it's there.

CHAIRMAN KELLIHER: Right. Thank you very much.

Colleagues?

COMMISSIONER BROWNELL: A couple of quick questions.

Building on the Chairman's question about the transmission issues, there's a fair degree of skepticism that the RTEP process is not in fact going to get married up with RPM; that the 10 and 15 year look is good, but there are a lot of short-term solutions that are relatively cheap. We talked about Black Oak the last time; that aren't getting done and that aren't actually even being considered that might in fact temper the need for this particular construct or elements of this particular construct.

What is the process for looking at the short-term solutions that are relatively cheap? We always talk in terms of, you know, these big projects and they cost lots of money; but how about the short-term ones, and what's the process, and could you get us a list of the ones that are under consideration? I think Maryland is very, very definitely concerned about this.

And along with that, is there any way that you can expedite the changes in the RTEP process to satisfy folks who are concerned, that is really isn't part of RPM and won't -- you're asking them to take something on faith that they're not really inclined to take.

MR. OTT: Again, there's multi parts to the question. The actual recent RTEP results actually have a fair amount of retrofits in these areas where we've seen fairly significant congestion. The Wiley Ridge area, there's a planned addition of a transformer there; the Beddington Black Oak Area voltage control device.

COMMISSIONER BROWNELL: Is that done, you put that out for RFP what, one, two years ago? You got some responses. Did you make some decisions?

MR. OTT: It's actually in the -- it's in the Regional Transmission Plan --

COMMISSIONER BROWNELL: But what was the response to the RFP? Did you work that out? There's been some concern that you have a process that is open and then closed.

MR. OTT: Yes. Oh, you mean the market windows for economics. Is that what you meant.

Yes, those market windows for economics, the actual economic planning process did not really result, cause the specific upgrades we're talking about here. These upgrades are for reliability violations that were identified in the recent Regional Transmission Expansion Plan.

The economic upgrade, or economic transmission planning has not resulted -- the market window has opened; there hasn't been substantive upgrades coming through that. The actual economic process does need to be redesigned, and we're actively working on that.

COMMISSIONER BROWNELL: What does 'actively working on'? Does that mean that they'll be a conclusion in the next month? In the next two months?

MS. ZIBELMAN: What we're anticipating, Commissioner, is that by June of this year we'll have a revised RTEP that includes a 10 and 15 year look as well as economic efficiency. But what we can do is we can provide you with the information you've requested.

In the process of last year's planning and this year's planning, there's been a significant increase of the requirements of the companies that, and the areas you're talking about, the level of investment they're making, to solve what have become reliability concerns; and we could provide you basically the list of what needed to be done and what is getting done through the current process, and then in March of this year we'll complete another five year plan, and then in June we expect to have the 15 year plan.

So we are working aggressively to get these done. It's an area, issue obviously of concern for us as well as the transmission owners; and the level of investment that we're talking about is much more significant then we historically had to do in PJM; and they are responding to that.

COMMISSIONER BROWNELL: Could you -- let's not wait until June. Let's get a look at that economic process and the projects that are being considered, and maybe get a list of all the relatively short-term projects that involve upgrades or something. And the process by which those get resolved.

I guess the club is only open to the existing transmission owners? It's not open to others to provide solutions to that?

MS. ZIBELMAN: Anyone who wants to propose a project in our footprint can, and we'll take it into account.

COMMISSIONER BROWNELL: And is it like 'first in' or do you have competition, or what happens there?

MS. ZIBELMAN: Under the terms of our operating agreement, there is a right of first refusal within the incumbent's footprint for reliability, but anyone who wants to propose another project, for example the Neptune plant, we'll take it into account in the planning process.

COMMISSIONER BROWNELL: There's a certain amount of skepticism that I know we'll hear later about whether in fact these forward markets will get either new projects built, get the right projects built, whether it's fuel diversity, whether it's baseload. They seem unpersuaded by the number of years of discussions you've had.

Is there anything more that you'd like to give us or other things you've seen in other markets that would give a little more confidence to the people who are going to be paying for this?

MR. OTT: Again, the key here is that the existing economic construct really doesn't provide a business model for these investments. Again, that's part of the process of creating a forward signal, allowing a transmission solution to actually offer in and get essentially a contractual obligation to get paid. That creates a business model for the transmission investor.

Under today's economic planning process, that's not true. So to address the capacity, locational capacity issues in having that forward auction with the ability for transmission to directly offer in there, get a cleared contract; so they can actually show that to an investment bank, that is a tangible business model, that will work.

Under the economic planning process we have today with the open window and the relative uncertainty, that has not worked. RPM is a partial solution. The expansion of the economic planning process is another solution, and that is being worked on, as Audrey said, in the near term.

COMMISSIONER BROWNELL: Well, I'll hold my questions. I have a lot more questions, but we'll wait to hear from others and see what they have to say.

COMMISSIONER KELLY: I have one quick one.

Can you explain the impacts that you anticipate RPM having on the market surrounding you? Particularly MISO.

MR. OTT: Effectively, if you look at the, again the capacity scenarios in PJM and the capacity prices in PJM, a lot of the rest of the market area, as you saw on my slide, has a relatively low capacity price, because those areas really aren't experiencing capacity transfer limits; they're more experiencing economic dispatch-type congestion. And that, again, is a different type of price signal, solving a different problem.

In the areas of essentially the border between MISO and PJM, essentially we have the ability for generation in those areas to sell into one market or the other, with one market having a certain type of capacity contract similar to what we have in New York. We have certain rules and procedures in place to make sure the capacity doesn't double-count. So today we've really already solved that problem with New York; New York has a different time frame for their capacity construct with different mechanisms; they have location, et cetera.

So we've really already solved that problem on the border through a set of protocols that say exactly how capacity gets sold in each of those markets; and then again how the energy actually gets delivered during emergencies, when we actually need the capacity construct to exercise itself, the classic contract, I should say.

So again, we solved those problems. We're working with MISO to discuss those protocols that occur during those times; and again, there are very short, numbers of hours of occurrence are fairly short. But what's important is we actually know which generator goes where for reliability, and we don't double-count. And that problem we have solved.

COMMISSIONER KELLY: And how is the protocol with New York working?

MR. OTT: The protocol with New York works fine. Essentially it's both an operational protocol and a forward protocol to track this, both in the planning process and in the -- operations has worked fine; we haven't had any issues.

COMMISSIONER KELLY: And with MISO, who are you negotiating with? Who are you working it out with, in MISO? The ISO?

MR. OTT: Oh, yes. You mean the discussions that are occurring on market-to-market coordination and the joint and common market coordination are between the MISO folks and PJM folks.

MS. ZIBELMAN: This would fall under the general operating agreement we have with MISO, to resolve these issues.

COMMISSIONER KELLY: Thank you.

COMMISSIONER BROWNELL: I'm going to jump back in.

So the deal with MISO will be done when? Having lived through the birth of the joint operating agreement.

MR. OTT: It's already in place now.

COMMISSIONER BROWNELL: No, I know the joint operating agreement. When will these protocols be worked out?

MR. OTT: Well, the emergency operations protocols are already worked out, meaning they're already in place and we know how that works. The roll-out of the joint and common market interactions, should we change our capacity construct?

COMMISSIONER BROWNELL: Uh-huh.

MR. OTT: And we would obviously, as part of that implementation, would implement additional protocols, if needed. We already have protocols today that deal with the fact that we have a capacity market and they don't. That's already in place.

COMMISSIONER BROWNELL: Right, but those would change.

MR. OTT: Those would change when -- if we change --

COMMISSIONER BROWNELL: So it's a work in progress that you know how the protocols will change, or you're waiting until RPM is approved and then you start to work -- I just want to make sure everything's in sync here.

MS. ZIBELMAN: We would work on it so that we'd understand what needs to be in place once we implement RPM; and I would say that with the maturity of MISO, with the maturity of the markets, what used to take a longer time takes a shorter time, because both sides understand the needs much better.

COMMISSIONER BROWNELL: What's the cost to implement RPM as it's currently proposed?

MS. ZIBELMAN: You mean PJM's internal costs?

COMMISSIONER BROWNELL: PJM's internal costs, and--

MR. OTT: The budget is between a million and a half and two million for systems, if you will, if that's the cost you meant. A project implementation-type cost.

COMMISSIONER BROWNELL: Uh-huh.

MR. OTT: Around that figure.

COMMISSIONER BROWNELL: You talked about the need for expensive retrofits, and certainly there's a fair amount of coal. If the generation units that are owned by utilities in the regulated markets throw their retrofit costs into rate base, and you have a fair number of IPPs who don't have that option, does that change the equation of the competitive markets in PJM? Does that cause earlier retirements? Have you kind of built that in?

MR. OTT: Well, effectively, the point would be that that information, if you will, in other words the fact that I have certain solutions that may be self-scheduled in to meet a certain load, and then the amount of generation I need over and above that, essentially would be revealed in the RPM.

In other words, say I had that situation where in an area I had certain generation that had already made that decision, was already contracted to load, whether through regulatory or through another type of contract. But then I needed another 400 megawatts, but I had 700 megawatts of this other generation.

The RPM would resolve which of those do we need, and we actually have them clear in the market, and which could go. Where today you really don't know, there's a lot of uncertainty, so probably all of them would go.

So the point is, the RPM actually resolves that because everybody has to come in with their forward plan. So I'd see that information, it would be transparent, and it would resolve the issue. Where today I don't have that information.

We have the information of course at PJM in a planning process, but there's no actionable signals sent out to the participants, because we have no forward market.

MS. ZIBELMAN: I would add, just simply a statement, that the notice -- I mean, if in fact you have some generators are on a regulatory regime and they are allowed to ratebase new investment, other generators have to recover the same investment in a market.

COMMISSIONER BROWNELL: They can't compete.

MS. ZIBELMAN: To the extent the market doesn't send the right signals, that just provides a further disadvantage to the competitive generation.

COMMISSIONER BROWNELL: I'll be interested to hear the generator's comment on that, because I think that's an issue that the markets didn't anticipate, and I'm not sure this actually does address that issue effectively.

MS. ZIBELMAN: Thanks.

CHAIRMAN KELLIHER: Any other questions?

Staff? Any excellent questions.

MR. MEAD: Thanks.

CHAIRMAN KELLIHER: We're listening.

(Laughter)

MR. MEAD: The opponents of RPM argue that the capacity problem in PJM is really a local one. New Jersey now and shortly the Baltimore-Washington area, there's a glut of capacity in the rest of PJM, and they don't expect a problem now or in the near future.

Do you agree? How do you respond?

MR. OTT: Well, again, they key here is that today, if I sit here today and I say where do I have my capacity problems? It is in a local area, but again you have to look at the basic construct that says, I have a global price for capacity that's essentially supposed to reflect what the price is for a reliability requirement.

Today that price doesn't differentiate by these different areas. So I have an inconsistency between the price that those generators see -- those local generators see and what is needed. I agree that today it's a local problem. But if you think about the concept of, we have an aging generation fleet. As we march forward in time, we're going to need to make fundamental decisions as a market community. Do we retrofit those generators? Do we build new ones?

That problem is going to expand both geographically and temporally. So the point is, we need now to create a construct that actually shows that information, creates actionable signals so people see it coming; because if we don't do it now, the red lights are going to be flashing in the future, when we have very limited solutions.

So what I would offer to you is that what we're seeing now is just indicative of the problem; and the problem is that we have an inadequate capacity crunch.

MS. COCHRANE: Let me ask the following question. You propose, I think 26 capacity zones? Is that right, ultimately?

MR. OTT: I think it could get to at least that. Again, many of them would not bind and therefore would not be commercially significant.

MS. COCHRANE: Well, there has been some concern raised that as we increase the number the liquidity will decrease significantly.

Do you agree? And if so, is that a bad thing? How bad a thing is it?

MR. OTT: We had very similar discussions when we used to have a single energy price across the whole system; and I think we sat here and said that when we put in locational pricing, the market as we know it will cease to exist; there will be no liquidity.

I've recently seen some statistics on the Nymex Western Hub contract that show almost vertical increase in the amount of forward liquidity that we're seeing there, the open interest in the trading.

So what I would submit to folks who say that is, I would agree that the current type of bilateral contracting would cease to exist, because it doesn't recognize the reality of the market. But it would be replaced by new types of bilateral contracts that would recognize location. You would have capacity hubs being created, you'd have basis products being created that allow people to do the hedging. You get the same type of development that you saw in the locational energy pricing; and while it is a fact that the current type of trading would essentially go away, because it doesn't recognize these realities, the fact is we're to be replaced with again a similar robust system that does recognize the realities.

MS. COCHRANE: Thanks.

CHAIRMAN KELLIHER: I wanted to actually ask one or two. Sorry to break my own sanction.

I want to clarify: Is this level of total transmission investments or quote, reliability investments, your chart? The levels are pretty low, at least in the 2005-2006 period. And what has been the level of transmission congestion during the same period? Hasn't it been increasing pretty significantly in PJM?

MS. ZIBELMAN: Right.

MR. OTT: Yes.

CHAIRMAN KELLIHER: So the level of investment has been fairly flat, fairly low, congestion level has been rising steadily.

MS. ZIBELMAN: What we're seeing -- primarily the transmission investments we've seen have been to solve reliability issues. Congestion has been increasing, and as we're saying, we need to step up the transmission planning to look at transmission investment that solves economic efficiency congestion issues at a much greater pace than we've done historically. We acknowledge that pace.

CHAIRMAN KELLIHER: Great. That was it.

Thank you very much. Very good discussion.

And now we'll call up the second panel, which is styled Panel I.

First, Gary Stephenson, Vice President, Commercial Operations, with Dayton Power and Light;

Reem Fahey, and if I mispronounce your name, please correct me. Reem Fahey, Vice President, Market Policy, Edison Mission;

John Young, Executive Vice-President, Finance and Markets, and Chief Financial Officer with Exelon Corporation;

John Judge, Director of Commodity Supply Planning with FirstEnergy;

The Hon. Alan Schriber, a colleague of ours, Chairman of the Public Utilities Commission of Ohio. Who had a very nice tie on this morning. I don't know where

Alan is.

And Andrew Tubbs, Counsel with the Pennsylvania Public Utility Commission; and

William Fields, Senior, Assistant People's Counsel, Maryland Office of People's Counsel.

Thank you very much. Why don't we start with Mr. Stephenson, and you heard the rules about the clock earlier, right?

MR. STEPHENSON: Yes. Good morning. I'm Gary Stephenson, I'm Vice President of Commercial Operations with Dayton Power and Light. Dayton appreciates the opportunity to share its thoughts today with the Commission and the broader market community with respect to their Reliability Pricing Model.

Dayton has been actively engaged in the PJM stakeholder process for some time, and is happy to express its opinion about the current capacity construct and potential improvements.

Dayton is a vertically integrated utility in a state that restructured its electric sector in 2001. Dayton continues to own essentially the same generation fleet that we owned prior to 2001. We continue to serve essentially the same retail load that we served prior to 2001, despite consumers' ability to switch providers.

We monitor the capacity markets closely, and we have a keen interest in their future direction; not only because of the financial implications, but also because of our role in helping to ensure reliability of the electric power system in the region.

It is our belief that the existing PJM capacity mechanism is flawed. PJM has recognized this problem, and its RPM proposal takes valiant steps to correct many of the existing deficiencies. However, Dayton is deeply concerned that RPM's administrative attributes will prove to be medicine that kills the patient; that is, the capacity markets.

First our thoughts on the existing market. The most glaring structural problem is the short-term nature of the procurement function. Administering a daily and even monthly auction process for such a long lead time item as generation capacity is in our opinion farcical.

These short-term markets are fundamentally mismatched with the need to provide long term price signals required for investment. Although the intentions of the late 1990s to accommodate retail deregulation with short-term capacity markets may have been logical, the effect was to render the wholesale capacity markets virtually useless.

Coupling the longer-term forward commitment to the realities of the plant siting and construction cycle is a reasonable path forward. Another key structural problem with the existing markets is the lack of a locational element. The tacit assumption that all generation is deliverable to all load regardless of location is at the very least removed from the physical reality.

The lack of a locational element probably is, as PJM has asserted, a major contributing factor towards degrading reliability in the eastern part of the system.

A key features of the existing market that should be retained is the ability of market participants to insulate themselves from the vagaries of the market. The self-supply features of the existing construct are an indispensable tool, in our opinion.

Turning now briefly to RPM, Dayton applauds PJM for developing such a comprehensive solution. However, we have deep concerns that certain administrative elements of the plan are cure worse than the disease. Dayton strongly supports the move to a locational element in capacity pricing. We are encouraged by the notion that by dealing with locational inequities in capacity markets, PJM will ultimately have the fortitude to remedy some of the locational inequities across its other markets, including reserve markets.

Dayton also supports the move to a much longer forward commitment with a market-based solution. However, as I said, we remain deeply troubled by the inclusion of an administratively determined demand curve in lieu of a market mechanism. One of our worries is that the curve seems susceptible to reshaping itself based on forces that have more to do with political clout than economic realities.

Dayton strongly supports letting participants retain the tools necessary to insulate themselves from the markets, if they so choose. We believe that participants choosing to self-supply should be required to meet the installed reserve margin requirement of PJM. We do not believe that those self-supplying should be required to meet a higher reserve requirement that could result from PJM's administration of the demand curve.

So in summary, Dayton believes that there are significant structural problems with the existing capacity construct. The RPM proposal addresses certain of those issues. We like the locational element, we like the long term forward commitment; however, the administrative nature of the demand curve is deeply concerning. It moves us away from a market-oriented approach and towards a structure that is open to undue political influence.

Finally, Dayton encourages all interested parties to work toward an informal resolution of the issues in the proceeding. Thank you.

CHAIRMAN KELLIHER: Thank you, Mr. Stephenson.

Is it Fahey?

MS. FAHEY: It's Fahey.

CHAIRMAN KELLIHER: Fahey. Thank you.

MS. FAHEY: Good Irish name.

CHAIRMAN KELLIHER: An Irish name! Thank you.

(Laughter)

I was turning into an Egyptian, I apologize.

I do want to just briefly thank those panelists who submitted written comments; it's easier for us to respond thoughtfully when we have written comments. I just want to make that point.

Ms. Fahey, thank you.

MS. FAHEY: Good morning. My name is Reem Fahey, I'm Division Vice President of Market Policy for Edison Mission Energy. It's truly a pleasure to be here, and thank you for inviting me again.

Edison Mission Energy owns or controls approximately 7500 megawatts of coal-fired base loaded units in PJM. PJM's existing capacity pricing and market rules do not provide assurance that sufficient capacity will be built or even maintained to meet the region's long term reliability needs.

As the Chairman noted, PJM recently experienced multiply reliability criteria violations in eastern PJM, particularly in New Jersey. This is due to a combination of increased generation retirement, lack of generation additions in the right locations, and a trend of steady load growth.

The serious threats to reliability clearly demonstrate that the existing construct is not just unreasonable. They are a product of the existing requirement that capacity need not be committed for longer than a single season. And the lack of adequate compensation under the existing capacity construct.

According to the PJM Market Monitor, net peak revenue has been below the level required to cover the full cost of new generation investments for several years. And below that level, on average, for new peaking units, even more troubling, units needed for reliability have revenues that are not adequate to cover annual going forward costs, prompting their owners to seek retirements.

To substantiate the above with some factual data, I would like to share with you some statistics from the 2004 State of the Market report. A new peaking unit needs approximately $72 per kW/year of net revenues to recover its levelized cost. However, the data provided by the MMU for years 1999 through 2004 indicate that on average a peaking unit only recovers $36 per kW/year, which really means it's only recovering half of what it needs in the market.

To address this lack of adequate compensation and its associated reliability problems, PJM proposed important features for RPM; the demand curve, location of capacity requirement, and most importantly the forward capacity obligation.

A forward capacity obligation of four years or more is necessary to allow new generation to enter the market well in advance of when the capacity is actually needed for system reliability. It also allows existing generators to make informed decisions about incremental investment or retirements. Advanced capacity sales by generators may improve creditworthiness of merchant generation owners, making it less costly and easier to finance existing plant expansion and construction of new plants.

The RPM's longer-term price signals will encourage generation and load to enter into longer-term bilateral contracts at least four years out. This will encourage generation investment by providing a more dependable revenue outlook for investors. Also, the RPM will reduce forward investment risk by providing more information on forward market conditions.

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

I would like to conclude by commending PJM for their leadership in both proposing RPM and filing it with the Commission. The RPM filing fulfills PJM's fiduciary responsibility to ensure the safe and reliable operation of the PJM markets.

Edison Mission Energy encourages the Commission to timely exercise its authority and set the disputed aspects of RPM for appropriate procedures that will permit the Commission to issue a final order by October of 2006. This would permit PJM to implement RPM, or a modified version of RPM resulting from the Commission's process by summer of 2007.

Otherwise, the drift we have experienced in this policy over the last five years will continue indefinitely. We urge the Commission to balance the need for a thorough review of this filing with the need to provide the market with much-needed clarity and regulatory certainty.

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

CHAIRMAN KELLIHER: Thank you.

Mr. Young.

MR. YOUNG: Thank you. Good morning. I'm John Young, Executive Vice-President and Chief Financial Officer of Exelon Corporation. We appreciate the opportunity to address this Commission on this critically important issue.

Exelon is responsible for keeping the lights on for over 5 million retail customers in Chicago and Philadelphia. On behalf of those customers, we are vitally interested in that PJM's generating and transmission capacity remain adequate to that task. In addition, Exelon owns or controls nearly 39,000 megawatts of generation capacity, most of which is in the PJM footprint.

Exelon has three key points I would like to stress today. One, the Commission should act promptly on the capacity market proposal. The Commission has the opportunity to create the regulatory certainty necessary for the timely development of generation capacity and better coordinated long term transmission planning required to sustain the reliability standards Congress and this Commission seek to maintain.

The sooner the Commission approves this proposal, the sooner the competitive wholesale market will provide reliability at the most efficient cost to customers.

Second, the RPM proposal on the table is the best approach for PJM to promote better coordinated and more rational planning for generation, transmission, and demand response to optimize resources for system reliability.

The forward procurement feature of RPM will enable transmission planners to make more effective and efficient decisions because they will know the specific location and timing of generation.

In our view, planning four years ahead for generation requirements isn't long enough, but it's a marked improvement over the current rules. Adopting RPM is a prudent evolution of the PJM marketplace.

Third, today's energy capacity and ancillary service prices within PJM footprint do not support the timely development of new generation or the retention of economically-challenged generation that is needed for reliability.

As part of my job, I continually review analyses of the cost entailed in developing new generation. I can tell you unequivocally that today's marketplaces do not justify a multimillion dollar generation investment. Wall Street is hesitant to finance and developers are cautious to invest when projected revenues won't cover project costs to build.

Reem went through some of those numbers, and our analysis basically supports what Market Monitor came up with. And just as an example, a simple cycle CT that may cost somebody $400 overnight to install per kW would require something like a $200 a megawatt-day demand or capacity price. The current capacity price in PJM is $35 a megawatt-day. There's an extreme shortfall for that, the cheapest form of capacity, to bring into this marketplace.

Also you can refer to it, I have more recently, some recent transactions of sales of existing generation have indicated that the market value of those assets run about 30 percent of a placement cost, transactions of sales of the various gas-driven assets that have been sold recently in the market.

Let me direct, the answer to the question posed to this panel by saying Yes, PJM's current capacity construct needs improvement, and No, the wholesale market is not broken. It is competitive and continues to evolve within the competitive context.

However, Exelon strongly believes PJM's current capacity construct needs to be adjusted to optimize planning for new generation along with transmission expansion, and demand response where and when each is the best solution. PJM's reliability pricing model is the next critical, important step in developing a sound and efficient capacity market to support continued, efficient reliability decisions throughout PJM.

Exelon fully supports implementation of PJM's RPM proposal. It is based on a wholesale market-clearing price mechanism that will optimize the entry of new capacity and wholesale markets at the right time and at the least possible cost.

Exelon believes that the RPM proposal will allow rational planning for future needs to balance all stakeholders' interest: consumers, generation, demand response, and transmission.

As we have identified in previous filings, the three key features of the new proposal are forward procurement, locational pricing, and the slope demand curve.

In closing, let me stress again that the most important point is that the Commission should not put off its decision. RPM already has been thoroughly vetted through the PJM stakeholder process. We urge the Commission not to send this proposal back to the PJM stakeholder process or extended settlement procedures. This Commission needs to decide this issue, and Exelon urges the Commission to decide it as quickly as possible.

Any details that need to be addressed as we move to full implementation can be dealt with as PJM suggests in a technical conference process parallel to this Commission's final decision.

As I said at the beginning of my remarks, the Commission has the opportunity here to promptly provide both the financial markets and developers the regulatory certainty and transparent price signals needed to foster rational capacity.

PJM has demonstrated the ability to create and run--

MS. DEMBLING: Time has expired.

MR. YOUNG: Okay. I'm done.

(Laughter)

CHAIRMAN KELLIHER: Thank you, Mr. Young.

Mr. Judge, and thank you for providing a written statement. I appreciate it.

MR. JUDGE: Thank you.

FirstEnergy also appreciates the opportunity to participate in this technical conference.

To begin, I'd like to answer directly the question posed to this panel. The current capacity obligation construct in PJM is not sufficient to provide adequate assurance that the necessary resources will exist for reliability. Changes must be made.

FirstEnergy and FirstEnergy affiliates serve more than 4.5 million customers in Ohio, Pennsylvania and New Jersey, and in two different RTOs. Although each of the States in which FirstEnergy operates has adopted retail competition, the approach taken has been different from State to State.

The RTOs in which we participate, PJM and MISO, each have different approaches to resource adequacy, and our generation portfolios and load profiles are different in each RTO. In MISO, they have more megawatt hours of owned generation than we have retail load; but in PJM we have more load than owned generation.

The result is, because FirstEnergy must reconcile these diverse perspectives within our own company, we've worked hard to develop a position on capacity markets that is evenhanded. FirstEnergy not only wants markets to work, we need them to work. And Chairman Kelliher, as you've pointed out, the choice is not between markets on one hand and regulation on the other. We think the challenge is to find the best way for regulation to strengthen the markets, balance the interests of both customers and investors, and at the same time enable rather than hinder the necessary infrastructure investments.

As I mentioned earlier, there are serious deficiencies within the current capacity obligation construct. We agree with the other people that have spoken here that there are subregions within PJM that will need additional generation capacity in the near term, well within the lead time that it takes to develop this new capacity.

Furthermore, there are generating units that will retire under the current capacity construct and create additional pressure on reliability levels. Already we're seeing increased congestion and pressure on the transmission system as more and more energy moves across the system to meet the demand of these subregions. Without significant new investment, these pressures will increase with time across the entire PJM system.

Worse, we believe there are features of the current capacity construct that obscure the problems the market faces, and in my prepared remarks in FirstEnergy's prior comments, we spell out in more detail the problems with the current capacity construct.

The proposed fixed RPM, even though it must be improved, addresses some of the critical deficiencies of the current market structure. RPM is locational, and in conjunction with the PJM RTEP process, it incorporates transmission and demand response solutions. Also, RPM adds two critical participants to the market; the RTO, and developers as well, who now have an opportunity to bid in future generation units.

Nevertheless, we also have a number of concerns about RPM, and I will highlight two of them. First, the new capacity market construct must recognize the important role that States play in assuring that essential reliability-based infrastructure projects are built and paid for with adequate revenue streams.

States typically have jurisdiction over the siting and permitting of transmission and generation facilities; and in addition it is the States that can establish mechanisms to provide the capacity revenue guarantees that the builders of new generation will need to secure financing.

Second, four years of price signals will not provide a sufficient incentive to the construction of new generation. After the most recent boom-bust cycle, generation developers and their financing partners are more cautious than in the past. Longer term, and by that I mean longer than four years, of guaranteed prices are required to drive new investment.

The fundamental RPM proposal with a crucial shift in sequence could provide a way forward. The proposed reliability backstop mechanism could allow PJM to request offers for new capacity installation. Each generation project that would be accepted in the backstop auction would be guaranteed to receive its offered price for at least 15 years.

But under RPM as proposed, this mechanism will only be activated after the amount of capacity cleared in the auction is below the established reserve margin for four consecutive years. We believe that a four year delay is too long to wait before assuring new resources will be developed.

Essentially, we are suggesting that on an annual basis, a mechanism to the RPM backstop be implemented first, followed by the residual auction for existing units. This approach allows the RTO and the States to decide the type of generation to be built and location, but leaves ample room for a market mechanism to determine who will build the new facilities, and at what price.

To accomplish objectives as complex and vital as electric reliability and well-functioning capacity markets, a longer term solution is necessary, and it must include more State involvement and a more directive planning function. Once this foundation has been laid, we believe capacity markets will work.

Thank you.

CHAIRMAN KELLIHER: Thank you.

Alan?

MR. SCHRIBER: Mr. Chairman, from all I've been able to gather and absorb over the last couple of years in the subject matter, I've come to the conclusion that we're all stuck.

I appreciate your efforts here today to bring a little light into the subject matter.

In my many, many trips to New York, it's become painfully clear to me that investment and generation is not dictated by those who own generation; it's dictated by Wall Street. Wall Street are the ones who supply obviously the money; they're the ones who provide the capital, and they are in pursuit of risk reduction, that is very clear to me.

So the question then becomes, how do we reduce risk in pursuit of building more capacity? Clearly the lower the cost of capital the more viable becomes the possibility of building capacity. We believe that State participation can have a positive outcome in this process, particular when it comes to a locational approach.

Now I want to compliment PJM; I think they've done some really good work and I don't think what they have done should be abandoned, but rather complemented; but what I think what we can propose from Ohio.

Now you'll note that Ohio's companies are very well interconnected. We do, however, split into two RTOs with a nice seam. You'll also note that we do have a collaborative called OVEC, the Ohio Valley Electric Cooperative, which has 25, 2800 megawatts of power, and all the four major companies in Ohio very well participate in that collaborative.

I think that there's a possibility for PJM, on a locational basis, to accommodate these collaboratives within a particular region. If you look at the chart, you'll see that poor Fred Baker is in that area of red, over there to the East; but we're out here where it's not as critical as it is in the East with respect to capacity constraints, and we believe that a lot can be done in terms of the companies that we have that can operate as a collaborative.

If we could for example draw a circle around our collaborative, de-list certain amounts of generation in order to fulfill our polar obligations, and then to meet those polar obligations if it's required to have more capacity, I believe the State can step in in pursuit of the polar obligations even though we are a deregulated state; I believe in pursuit of polar obligation we can enable the construction of capacity.

Additional capacity could be bid out or bid in, I guess you could say, in order to fulfill whatever else is needed. The bottom line is that we need iron in the ground in Ohio.  We want capacity that we can point to, and it's not obviously clear to me that within the construct of RPM there is actually iron in the ground that we can point to.

We think that we need base load; we know that we need base load.  We're told that if base load construction is not going to be forthcoming under the current construct, and we actually believe that.  We believe that PJM can continue to dispatch what it is that they need to dispatch in terms of power; we believe that they can also handle the transmission elements.  But we do believe that when you have companies within this particular area who are so intimately interconnected as are FirstEnergy, Dayton Power & Light, AEP and Synergy, we believe that they as a collaborative can meet as a collaborative the requirements, the reserve requirements required by PJM.  If one company is short, the other might be long, but if it's the 15 percent plus 1 or whatever the case may be, we feel that that can be met in that type of a collaborative basis.

So we feel that, and we have already commented on what we feel the drawbacks are of the current PJM structure; even PJM recognizes what they are. We're not inclined to get into that because we filed plenty of comments, as we have as a State and as we have as members of the organization of PJM States.

But nevertheless I would suggest that we could approach this with an open mind. I think we could work in concert with PJM, and I would hope that this works through Ohio, and I would hope that this could work for other States.

Thank you for your time.

CHAIRMAN KELLIHER: Thank you.

Mr. Tubbs?

MR. TUBBS: Thank you. Good morning. My name is Andrew Tubbs, I'm the Energy Counsel for Commissioner Kim Pizzingrilli of the Pennsylvania Public Utility Commission.

Today I offer these remarks on behalf of the entire Pennsylvania Commission. Initially we would like to thank you for the opportunity to present today, and for holding today's technical conference, in your continuing efforts to facilitate a resolution to this complex but important issue.

The enabling statutes that served us are in competitive forces, both in the wholesale and retail markets, were predicated on the idea that tangible benefits and market efficiencies could be realized through competition rather than traditional regulation.

The move away from former regulatory paradigms is undeniably a work in progress, as discussion continues on the right form of market structure and wholesale market, and many retail markets including our own in Pennsylvania, are still under a transitional competitive model.

To succeed in our endeavors of establishing competitive markets, suppliers and consumers must have a means of reaching each other, through price signals based upon a collective wisdom of a market free from abuse; and that will enable suppliers and consumers to make future plans on new and existing capacity transmission and energy efficiency.

PJM's Reliability Pricing Model purports to resolve localized reliability concerns in regions of PJM. The Pennsylvania Commission must and does value system reliability very highly. However, we remain concerned about the proposal. We believe that it may be too administrative in nature, that it may be perceived as the end state of our markets, and therefore compromise the long term goal of establishing reliable, efficient and competitive wholesale electricity markets.

Specifically, theory does not always predict actual behavior. That is evident as forecasted high LMP prices have yet to result in substantial new generation investment in capacity-deficient regions of PJM.

Capacity pricing mechanisms are not a fundamental element of wholesale market design. In PJM they were designed to allocate generation investment responsibility among a handful of vertically-integrated monopolies. RPM supporters and its detractors appear to agree that capacity markets are in essence a substitute for a well-designed wholesale generation market, and that RPM is engendered by other inadequacies that are in the current capacity market construct.

The Pennsylvania Commission has filed a protest in this proceeding, not because we oppose the change to the existing capacity construct, but rather do it to our concern that RPM, as currently proposed, may stall continued improvement of competitive wholesale markets, efficient transmission grids, and robust demand response.

PJM has identified a number of problems for the impetus of its filing; lack of transmission capacity and generation investment in certain regions, the historic volatility of the capacity market in PJM, and a lack of locational economic signals for investment in operational characteristics and load response.

PJM's existing marginal pricing, energy market design, was originally intended to address many of these problems by providing economic signals, sufficient incentives to invest, and rational consumption. PJM's filing does not offer a clear reason as to why LMP is not working. In fact, PJM recognized that something more than a revision to its existing capacity market is required.

Commenters have remarked that nearly all of the new generation capacity currently being added is gas-fired peaking capacity. This is a cause of concern. However, we question whether RPM will actually achieve its stated goal of maintaining appropriate fuel diversity in the region, both in fuel source and operational characteristics.

That is to say we believe that it is essential that our market incent the construction and location of base load generation and demand response.

The Pennsylvania Commission values its working relationship with PJM and stakeholders, and we are confident that these relationships will move our markets forward. However, what should not be lost in this proceeding is the opportunity to seriously think about the plan for our wholesale energy markets in the future. While we commend PJM for moving the ball forward on the future capacity construct, concentrating only on the capacity market without addressing the other components of the market at the same time seems inefficient and an ineffective means to address the future of our wholesale energy markets.

If this proceeding is to set a pattern for wholesale market design, we should have some idea what comes afterwards. What is needed is a clear roadmap and commitment to implement mature market design that delivers economic efficiencies, market transparency, robustness and reliability that competitive wholesale markets have promised.

Thank you.

CHAIRMAN KELLIHER: Thank you, Mr. Tubbs.

Mr. Fields.

MR. FIELDS: Thank you. Good morning. I'm William Fields, I'm with the Maryland Office of the People's Counsel.

OPC is an independent State agency that represents the interests of Maryland's residential utility customers. OPC thanks the Commission for this opportunity to provide our views on these important reliability and market issues. In this case, OPC is a member of the Coalition of Consumers for Reliability; however, my comments today are only on behalf of my office. CCR is a coalition of seven consumer advocate offices and public power entities.

My basic response to the questions posed to this panel are One: The current market system has produced sufficient revenue streams overall to ensure more than enough capacity to maintain reliability. There is no justification, and it would not be prudent to make the fundamental changes to the PJM market design that PJM proposes. And Two, prior to a major restructuring of the capacity construct, weaknesses in the transmission planning process need to be addressed.

As a member of CCR, OPC has filed a protest in opposition to RPM in which we have looked carefully at the arguments and claims regarding problems with the PJM markets. The first question that should be asked is whether there is evidence that the PJM markets are providing sufficient compensation to ensure reliability.

Under the current PJM market design, generators received market-based revenues and accordingly bear the risks of such market-based compensation. Market participants form expectations of future levels of such revenues, and investors can make decisions based on this information. This creates opportunities for sharing the risks of investments through bilateral contracts.

The evidence shows that this compensation system is sufficient to induce new investment and maintain adequate reliability. For this inquiry, we have looked at the picture of the global capacity situation in PJM for information and seen sufficient capacity reserve margins through the start of the next decade. We have looked at the PJM queues and seen plants continuing to come into the queue and move through the process to construction.

While the global capacity situation is not the entire answer for reliability, it is the place to look for evidence that the basic structure of the market is not working, and that evidence is not there. As the basic elements of the PJM electricity markets are not broken, we should not try to fix them. The RPM proposal is designed to increase and further stabilize compensation to generators, but we do not see evidence that either change is needed.

I certainly understand that there are people who are of the opinion that the fundamental changes to the PJM market design proposed in the RPM filing will work out and even be a benefit to customers in the long run. However, we cannot support a radical redesign of a system that appears to be working in the hopes that years from now consumers will see some benefit.

There is every indication that RPM will raise prices for consumers, and on their behalf we are looking for solid evidence of a problem before those higher prices are imposed.

In the CCR protest, we described an alternative; the enhanced integrated transmission and capacity construct, that keeps the basic fundamentals of the PJM electricity market in place. We also provided an alternative to that alternative, if you will: In case the Commission is persuaded that an electricity market model where investors take the risk of forward revenue streams when making investment decisions will not work.

If this fundamental aspect of the market is not working, implementation of RPM on the hope that sufficient investment will come is not the right response. Rather, we should explore a system of long term contracting, where capacity needs are independently determined and procured through a competitive solicitation of some kind for long term commitments.

This is all not to say that there are no issues that need to be addressed if there is no opportunity for improvement. PJM has identified deliverability issues for certain locations on the system. The role of transmission planning and reform of that system should not be glossed over in this discussion.

So far the PJM planning model has taken a minimalist approach to transmission planning; i.e., what upgrade is needed to address the reliability criteria violation identified in a five year window, as opposed to an approach that fully evaluates the system and provides the upgrades that are needed to stay ahead of reliability issues and provide a platform for competition throughout the region.

We have seen a small first step in that process with the expansion of the planning horizon to 10 to 15 years for certain types of upgrades. PJM has been working through a process with its stakeholders on other aspects of the planning issues.

To get a good result for customers, it is critical that the planning element be fully resolved. With the RPM filing, we are going about this in the wrong order. The Commission should direct PJM to come back with a comprehensive planning process that incorporates long term reliability, scenario analysis, and market efficiency planning components.

Once that is understood and functioning, the Commission can take a reasoned look at what is necessary on the capacity side.

Thank you, and I look forward to answering any questions you might have.

CHAIRMAN KELLIHER: Thank you, Mr. Fields.

I'll ask a few questions, turn to my colleagues, and then hopefully Staff will have some excellent questions to follow up on our half-excellent questions.

But if I heard the panel right, everyone other than Mr. Fields believes that there is a problem under the status quo. Is that correct?

PANEL: Yes.

CHAIRMAN KELLIHER: Okay. Mr. Fields, though, you put forward an alternative nonetheless, in the event there is some action that's taken with respect to PJM reliability that is part transmission, part long term contracting. Correct?

MR. FIELDS: Well, I was trying to describe two different alternatives that we put forward.

CHAIRMAN KELLIHER: Okay.

MR. FIELDS: The first one is part -- is first transmission as well as some improvements to the current capacity model, locational elements, implementing it on a yearly basis as opposed to a daily basis. Those are probably the two main components.

As I said, an alternative to that alternative would be a long-term contracting model, if it was believed that a structure where we did this on a basis where investors are taking that investment risk from the beginning, if we don't think that's going to work then let's do something that actually gets the capacity by going out for contracts that have long term commitments and get it.

I didn't mean to overstate that -- I didn't mean to say that there were no problems with the capacity market; I tried to say that the overall approach of the capacity market is working to attract investment by looking at what we've seen so far, the evidence we've seen so far. I didn't mean to say that it was perfect.

CHAIRMAN KELLIHER: Sure. It may have worked, but is it still working? Between 2001 and 2004 about 25,000 megawatts were added in PJM. But my understanding is last year there was a net loss; that the retirements outpaced additions, and that we're looking at very low levels of investment in the future.

So it's possible to argue that capacity markets did work to attract investment for a period of time, but there was a net loss of generation in PJM last year. So it seems reasonable to suggest maybe it's not working currently.

MR. FIELDS: Well, we still have -- I updated some of the numbers; I looked to update some of the numbers we put in our October protest. As of January 30, PJM is projecting a 23.3 percent reserve margin for the '06-'07 planning year. That number was a little higher when we filed in October. It's not unexpected or it shouldn't be unexpected that in a period where you have overbuilding that overall number is going to come down.

We've also, there are a lot of projects in the queues right now. I think the number we quoted was 21,000. In October when we filed our protest, there was approximately -- we quoted a number, 2745 megawatts under construction in PJM. The January 30th number is 3,858 megawatts.

So we're trying to look at these numbers for objective evidence that things aren't working, and we're having trouble finding it.

CHAIRMAN KELLIHER: Great. But I believe everyone else in the panel believes the status quo is failing, and that the Commission, there needs to be some action by the Commission. In your long term contracting alternative, whatever action we take, if we act, we would have to be bounded by our legal authority, and we have jurisdiction over wholesale sales, we have jurisdiction over sellers, but we can't compel a buyer to enter into a long term contract.

Chairman Schriber can; his colleagues can, arguably, but that approach is something that will be very hard for the Commission, really, to address.

Let me address Mr. Tubbs. He had an interesting quote from Joe Bowring, talking on energy-only market as an alternative. Well, he isn't actually postulating it as an alternative, but that is an alternative that some have identified, that instead of capacity markets you rely on energy-only markets, and usually the advocates of that point out those markets have to be either unmitigated or much less mitigated than they are currently.

Is that what you're proposing? To a less mitigated or unmitigated energy-only market?

MR. TUBBS: I think that what the Pennsylvania Commission is saying that we believe there are problems with the current capacity construct that need to be fixed. We recognize that there are those generators that are on the margins that are not receiving adequate revenues to sustain their operation.

I guess what we're saying is that the overall generation capacity of the market is there, that there's ample capacity, but we need to address those localized concerns.

What our concern is is that the Pennsylvania Commission has been, and assisted PJM in getting ICAP installed. I mean, the Pennsylvania Commission was there from the get-go. And while we have continued to debate the ICAP model, UCAP through the ram and through the fog, which is an apt term for a group that we had on this topic, it's been a long process to get to here. And our concern is that RPM is potentially just another ICAP debate waiting to happen for the next ten years; and that we should not lose sight of addressing short-term, identified short-term problems and lose sight of where we want our markets to go in the long term.

CHAIRMAN KELLIHER: Let me ask Ms. Fahey and Mr. Young, if you look at an alternative as an energy-only market, that's unconstrained or much less constrained, is that superior to a capacity market? Is a capacity market the next best alternative to a long term contract? Is it the next best alternative to an energy-only market that's unmitigated or less mitigated?

MS. FAHEY: To be completely honest --

CHAIRMAN KELLIHER: Sure. This is a public session, I mean --

(Laughter)

MS. FAHEY: An energy-only market, if the regulators are willing to go there, which means you're going to have, you're going to allow prices to go to very, very high levels. We're talking about, maybe you know $7,000 to $10,000 per megawatt-hour.

If the regulators are going to say "Yes, we're going to allow it to do that," and you all promise that when the price gets to $10,000, you wouldn't step in. And when the AGs, attorney generals of States, or when governors and all the politicians come screaming to you, that there's somebody who didn't hedge, and now they're paying $10,000 per megawatt-hour -- if you promise not to intervene, we would love that. It's a better proposal for us than this stabilized, you know --

CHAIRMAN KELLIHER: It's better because it's more profitable, or it's better because --

MS. FAHEY: Yes. Because I mean --

(Laughter)

MS. FAHEY: Absolutely. I mean, you know, volatility is not a bad thing for people who are in the merchant business.

It's just -- I feel, and I don't intend to insult anybody's feelings or hurt anyone's feelings, but it's just not -- I mean, why have this debate? We know we're not going to allow prices to go to $10,000 per megawatt-hour, and we know that the regulators will step in.

So yes, it's great Ivy League stuff, but it doesn't work.

CHAIRMAN KELLIHER: So would you then suggest that a capacity market is in effect a reaction to mitigation in the energy-only market; that that creates the need for a capacity market? The mitigation does?

MS. FAHEY: Actually, if I could just spend two minutes to explain that, because people just get sort of puzzled, why isn't a new peaker making enough money in the market, and the answer is very simple. We designed the markets to be inherently long; so we designed the markets to be reserve plus 15 percent.

So think about it this way: To the extent that you have mild weather, and to the extent that all the generators performed very well in the summer. No generator trips. That peaker that you need for reliability is going to run 10 hours, maybe, 10 hours in the whole year. So if that peaker is going to cover its cost -- I mean, we'll do the math -- they need $7,000 per megawatt-hour in all these 110 hours.

Are we going to do that? No. Again, we're not going to allow prices to go that high. So I think it's the combination of these two things that inherently, because of reliability issues and because the way we've designed this market is we need to be long, it's an insurance policy.

So the 15 percent and the fact that they can't recover their costs, then that missing money has to be made up somewhere; and it has to be made up in the capacity market.

CHAIRMAN KELLIHER: Mr. Young?

MR. YOUNG: I would agree with all of that, and I think that from the consumer side -- I was taking your question from the consumer side, this does mitigate that; it provides capacity to avoid those price spike times, it flattens it over a number of years.

Is this the ultimate answer and what everybody desired? No, this was the result of five years of people trying to hash it out. In my comments, we'd have liked it to have been a longer period than four years.

But to the pure generator, energy-only prices, if unmitigated, look in the short-term to be more profitable. I don't think that's good policy because somebody's going to respond to that, and that response is typically onerous.

So you don't want those real rich times because you're going to pay for them sometime. I just don't believe that's good policy. So from the generator side, we also support the mitigation effect that a capacity market would have. You know, obviously from the 5 million customer side, we think that's a good thing as well.

And I've done the same math that Reem was talking about, that I come to $10,000 to $12,000 a megawatt-hour is what that peaker needs, in a perfectly designed system that we could all sit around and agree to that's kind of where it is, and nobody's going to get that.

So the other issue about energy-only markets that become problematic from a planning perspective, the timely response to those price spikes is very difficult when you've go to do permitting. These are not necessarily overnight responses that are necessary. The time function of generation development is not as rapid as the energy-only markets can go from $30 to $30,000 and nothing wrong be going on.

So it doesn't sync up with the timeliness of, and what ends up happening, the generation that gets built in that domain -- the Chairman talked about the bankers run the show. Well, they're going to put the risk/reward construct together. It's not that you can't do it, it's just going to be very expensive.

So their money is going to chase where that risk is not zero, but where the risk/reward balance exists. And it may be in PJM, it may be in Texas, it may be in California, it may be somewhere else. They're going to find plenty of places to invest their money. It's getting the balance between that risk-reward opportunity that an investor has that's really the serious element there.

CHAIRMAN KELLIHER: One question about bilateral contracts. What's really the average term of bilateral contracts currently in PJM?

MR. YOUNG: I don't know about in PJM. We have a couple; one is to expire the end of this year, one that's going to expire in 2010, but those were transitions to, into full competition, and the State set those up.

The bilateral contracts that we have are run, some two or three years, but there were some legacy things, before the buyers, not the sellers.

CHAIRMAN KELLIHER: Alan, did you want to say something? You looked like you wanted to say something at some point there.

MR. SCHRIBER: Yes. With respect to energy markets, to the extent that you can draw a circle around an area, it seems to me that yes, at the margin you have peakers that are very expensive. But if they're blended into the portfolio and that portfolio in general meets whatever reserve requirements are necessary, I don't see that resulting in a $10,000 a megawatt price to the consumer, I see that as a blended rate.

And that's why I think it's important to think in terms of the broader picture, of a broader portfolio, even if it means bringing together the portfolios of four or five companies. And in that regard, it doesn't -- I'm sure that that doesn't play well with merchants.

On the other hand, once the polar obligation is met, and I think we grossly underestimate the importance of the provider of last resort. In each and every state, even those of us who are deregulated, that really is a very dominant feature of what we do. You have to have that polar obligation fulfilled.

That could be fulfilled, to some extent, by this portfolio including that which is bid out potentially to merchants.

CHAIRMAN KELLIHER: Thank you.

Colleagues, questions?

COMMISSIONER BROWNELL: Reem, let me just make sure I understood what you said. And that is that price volatility of the 7, 10, 12, whatever doesn't work. You meant it doesn't work politically. In terms of an economic construct, volatility does in fact work in lots of markets every day.

So let me just be clear about that.

MS. FAHEY: That was exactly my point.

COMMISSIONER BROWNELL: Okay. Because people may take away that it doesn't work. And so since we generally ignore economic constructs when we're doing these markets, it's probably a good idea to just get the facts in.

(Laughter)

Let's just say RPM doesn't happen. Would you retire generation? Would any of you be retiring generation?

MS. FAHEY: Actually, it's a great question. I speak from severe pain on this issue. We retired over 3,000 megawatts of generation already in the region. They were combined cycle units and peakers, because again we do the math, we're getting less than half of what we need to cover a fixed cost. And as a merchant generator, we're in this business to make money, it's not a charity. So we can't. We can't keep the units on.

So yes, the answer is absolutely.

COMMISSIONER BROWNELL: John?

CHAIRMAN KELLIHER: Nora, can I just step in? Just for a moment.

Did you offer to sell any of those units beforehand? Were there no takers? No one wanted them?

MS. FAHEY: We did an informal, but -- we have great pride, our company operates units very efficiently. Nice company plug here, but -- so we feel that if we can't do it, there is no one else who would do it.

We did an informal solicitation, and there was no issue; PJM looked at them, there was no reliability issue, and they're gone, forever.

CHAIRMAN KELLIHER: Thank you.

MR. YOUNG: And I have, too. One of the first things I did, I came on as running our nonnuclear assets in the first year I worked for Exelon, and we had to retire, and we filed with PJM to retire two units; and we look at those units every year just on an economic basis, because we're putting capital back in them every year, is that worth it?

And the marginal ones, if they're marginal we try to keep them. If it's just clearly a loser, we've filed and retired units in Pennsylvania and in New England as a result of just the economics. They're environmental-cost driven, they're fuel-cost driven, they're technology-driven; there's a lot of reasons why, but they're just not economical at the end of the day.

COMMISSIONER BROWNELL: Ohio, you've got rate stabilizations plans longer than I'll live, so you probably don't feel that pressure.

MR. JUDGE: Yes. In PJM, we only have a few assets; a nuclear plant and a pumped hydro plant. So those really aren't retirement issues. But in Ohio, in MISO, we have coal units. And depending on how the next few years play out in terms of fuel markets and emission allowance prices, against the power prices, we could face some retirements there; there's a number of them that are in the gray zone. It just depends on how the next few years the markets play out.

COMMISSIONER BROWNELL: Same is true of --?

MR. STEPHENSON: At Dayton, generally with respect to our polar obligation, we've hedged, through the use of assets that we own. So those assets are critical to managing and hedging our long term polar obligations.

COMMISSIONER BROWNELL: Which aren't going away. Alan Schriber is a friend of mine, but there is some large number of folks that believe the rate stabilization plans that are in place have really precluded any serious competition; so the polar obligation is a consequence maybe of people's behavior, but largely because people can't compete. I think that's pretty much the take on that market.

John, you said four years might not be enough; Andy said 'I see no exit strategy'; I think a number of other states have said that, too. So what happens in four years? Or eight years. We say "Gee whiz, four years was not enough." Or "this didn't work."

How do you answer the exit strategy issue?

MR. JUDGE: I think our answer was kind of built in to our comments. We think we'd see the backstop coming, and it's going to bend up being implemented; and therefore we think it's probably more economic for the system as a whole to just go ahead and implement it first, and put that into place.

In other words, go ahead and make those decisions so that we get new units coming, rather than wait until we see a shortage.

COMMISSIONER BROWNELL: I understand why you want to do it, but there's a certain amount of take-it-on-faith again here. And I think what some of the States are saying is, we're not sure this isn't now a lifetime construct. Which may be a function of the political unwillingness to look at real prices. I mean, that's a decision we seem to have made.

So I guess, is there anything other than "I guarantee you this will work and we'll just see"? That's pretty much what I'm hearing.

MR. YOUNG: You may have said it right. The way we typically look at it is, our concern is that the costs of waiting, that the customers will bear, aren't worth taking the risk. And so since we can come up with another mechanism to prevent that, to go ahead and use it.

COMMISSIONER BROWNELL: Okay.

Andy and maybe Mr. Fields, could I characterize what you said in this way: Andy, you probably more clearly, I think, and I may be misinterpreting you, Mr. Fields.

RPM married with a better transmission planning process would be acceptable for a short term with some off-ramp exit strategy. Is that how Pennsylvania feels?

MR. TUBBS: I think that's a fair characterization, that we think that RPM has its positive points. We like the forward commitment, we think that forward commitment makes sense. We also think that the locational component makes sense. We do have concerns with how both of those are set up, but we're willing to work on changes to the current construct.

It's just where we're going after this contract. We want to know where we're headed. Where are we headed.

COMMISSIONER BROWNELL: Mr. Fields?

MR. FIELDS: We have tried to say that

improvements in the transmission planning process are critical; improvements to the capacity construct are an important thing that should be done, not the way RPM goes about it, but other ways. We haven't taken a position on, do you need an off-ramp from a capacity type of construct.

COMMISSIONER BROWNELL: Alan, not to leave you out, it sounded to me as if you were saying this is a problem for other people and we're going to solve it within the confines of our own State with our own companies. Is that --?

MR. SCHRIBER: Not precisely, but I would say -- to be more precise, rather, I would say that this is not about Ohio, but I am from Ohio. And I think that looking at it from a zonal perspective, locational perspective a zonal perspective, it's something that we can do, it's something that others can do if they're similarly situated.

Again, I go back to this map that Audrey gave us, and you can see that we're out there, so far out in the hinterlands and so far out of criticality that we're covered up by a label.

So I suggest that --

(Laughter)

COMMISSIONER BROWNELL: We don't like to think of Ohio in that way, Alan.

MR. SCHRIBER: Right. But nevertheless, I think there is a significant role for PJM to play with us as we play within our own playground. And that would be --

COMMISSIONER BROWNELL: So some kind of a zonal construct where you felt you were not paying for another person's problem but in fact held harmless because you or your companies had built sufficient generation to serve your load?

MR. SCHRIBER: That would be correct.

COMMISSIONER BROWNELL: Is that correct? Okay.

MS. FAHEY: Can I comment on that, if I may?

COMMISSIONER BROWNELL: Sure. Like a little debate.

MS. FAHEY: Just two comments. The first one is there a built-in off-ramp in RPM, and I think the answer is Yes.

To the extent that you reach energy markets that are compensatory, the demand curve collapses, and nobody will get a penny for capacity. So to the extent that the new peaking unit that entered the market is making gobs of money from the energy market, that's great because the demand curve will reflect that, because that's exactly what they do.

They take your capital cost, levelized capital cost, and then they subtract the energy revenue. So there is a built-in off-ramp. So that's the first comment.

And the other one is, the Ohio issue. If you look at the simulations at PJM that -- they're exactly doing that. They're not making Ohio pay for New Jersey's problem. If you look at the simulations that they did, the model takes in to consideration the excess capacity, not just within Ohio; within the Com Ed region and Dayton as well, and it says: that whole region does not need extra capacity, and prices are very low. I mean, we're not happy about that, but that's reality, that's what the model says.

If you look at the prices that the last simulation showed, prices for capacity in Ohio and in Chicago is $6 to $8 per megawatt-Day, nothing to write home about. And that's exactly the right approach; is that nobody's paying for anybody else's problems; the people who have a problem are picking up the tab.

COMMISSIONER BROWNELL: Thanks.

COMMISSIONER KELLY: I'd like to ask Andy Ott to come up. And sit down.

Sorry to put you on the spot here, Andy, but I think that you could help with some answers.

We've heard some concerns about the demand curve mechanism in particular, and some requests that it be a market mechanism rather than an administrative mechanism. Is there a market mechanism that exists that could be substituted for it? And if so, what would be the implications of that.

MR. OTT: Okay, I think if you -- again, as demand curves go, demand curves put in an administrative price cap. And the feature of a sloped demand curve which, as Raymond pointed out, the sloped demand curve actually looks at the varying levels of reserve requirement that are available or reserves that are available. It also takes into account the feedback mechanism that says how much revenue was gathered historically in energy?

So it actually again reduces those administrative components. Also with the deployment of the demand curve in the RPM, you have the supply curve and the demand curve, both considered in the optimization, in the clearing. So therefore as the price goes out, as the reserve levels grow, essentially the offers of the generators start to kick in once you get above the base level of requirement, and start to impact the market result.

Actually in the simulations you see that we've presented, that's actually the feature of the demand curve that's kicking in that's keeping the price very low in the rest of the market. The majority of the market in these simulations has a $6 price, and it could be zero, depending on --.

So I think I would offer that some demand curves are very administrative. We tried hard to make this one the more market -- although it's not purely market, because you have to have some administration. So I think there's a balance, and again that's really the critical part.

COMMISSIONER KELLY: So you're saying then, in a nutshell, correct me if I'm wrong, that it is administrative but it's highly informed by the market --

MR. OTT: Right.

COMMISSIONER KELLY: -- and it's, the curve itself is predicated on market prices, market signals, market performance?

MR. OTT: Correct. That's exactly right, the curve itself, the feedback mechanism or the curve itself is actually adapted based on the market performance results, so that you actually see that dynamic.

Further, the ability for a new entry and demand response to jump in actually also obviates some of the intervention that curve would bring. So the point is, the curve's there if you need it, but the clearing mechanism itself, if the market found it didn't need it, it would sense that very directly in the model.

And again the feedback mechanism allows, you know the exit strategy, if you will, the fact that the capacity price would just implicitly go to zero on its own, as you see it doing in most of these simulations; effectively allows the administration to only kick in when you need it.

That's really the key.

COMMISSIONER KELLY: There is some concern, I heard expressed, that RPM -- you have to take it on faith, and it may not result in steel in the ground.

What's the response to that? What's the best response to that? How much faith is involved here?

MR. OTT: Okay. Well, I think there's a couple types of faith. The first type of faith is to say if we find we don't need a capacity market, you know, and we just put this in and the result of the market shows we don't need it, this mechanism we just talked about would say it's just going to implicitly come out, because the prices will go down.

The other component though is to say "okay, what if we put it in, and in fact we don't get the investment?" Well, the key point here, again today if we don't get investment -- okay, there's really no financial consequence, if you will, to any entity, because they really didn't have a forward commitment. Under RPM you have that four year forward commitment.

So say a new entrant bid in or an existing generator bid in, and the price was $200 a megawatt-Day. And they said, "You know what? I'm not going to bother building, I'm going to get out." Well, they're now on the hook, essentially, to replace that. So the financial incentive for them, even if it's only for a year or two years, three years, whatever, is extremely sharp.

Now will they actually come in? Again, is index based on, this is the administrative part, the cost of new entry. If they don't bid, you get a ratcheting up where you get two times the cost of new entry, et cetera.

So the point is, the only reason they wouldn't build in that instance of course, because it's economically rational to do so, is if you had some kind of reason they couldn't build because they couldn't site or whatever. But that's a sort of other issue.

MR. SCHRIBER: Commissioner Kelly, can I ask a question sort of along the same lines, getting back to the demand curve?

COMMISSIONER KELLY: Sure.

MR. SCHRIBER: Is it not possible that this demand curve, as we're looking at it today, could shift significantly over time? If I'm making some sort of a judgment today upon what I'm going to do, but three or four years out it does shift significantly, brought about by some phenomenon? Could this not cause a significant disruption to planning in general?

MR. OTT: Well, obviously things can change. In other words, forward conditions can change, markets by their nature are affected by people's decisions.

The basic fundamental, though, is that the price that results from the market and from that demand curve interaction must be logical. Meaning that if I need a generator; in other words if a generator installed himself into the system and that generator is needed for reliability, the demand curve mechanism and the clearing mechanism in the RPM guarantee that the price will reflect the fact you need them, and they'll get paid.

The fact that that generator now has confidence that if it can compete, it can do what Reem says, and actually be the best alternative, the most efficient. They're going to win, and they're going to get the auction.

So even if all the market would change, that fundamental reality that you're going to have consistency inspires confidence. Today's market, effectively we don't have that. They can be the best they can be, and the price won't affect reality, and that's the problem.

In a nutshell, what the RPM does is brings that level of stability. Not a guarantee; in other words, it's not saying "I'm going to give you a guarantee that you're going to, if you install this, you're going to win, and you're going to recover your cost."

What it's saying is I'm giving you a guarantee that if you're needed, okay, and you perform as best as you can -- you know, better than anyone else can, you're going to get the money, no matter what happens. That's the real key.

COMMISSIONER KELLY: Andy, does the RPM model err on the side of incurring load-serving entities to go along with capacity? Maybe err is the wrong word, but.

MR. OTT: The RPM model would encourage load-serving entities to hedge forward, because essentially the cost of not hedging forward is very dramatically revealed in the forward pricing. So I think the direct answer to your question is, it would ensure that -- if you think about the IRP processes of the past, the point was, you had a certain reserve requirement, maybe 10 percent, 15 percent, whatever it was. But they actually planned for a couple percent above that, because nobody wanted -- you didn't want to get caught short and have a reliability --. the RPM actually replicates that in a market sense.

It says, essentially, "Well, we know we have a 15 percent margin, reserve margin required." The fact is, most prudent people are going to plan for a couple failures along the way, et cetera, so they're probably going to hedge themselves to 17 percent, maybe. And that's really what you saw in the past through various mechanisms. And essentially this replicates itself.

So the prudent may be encouraged to somewhat over-hedge, but not dramatically over-hedge. Again, so it's a balance. And really, each individual within this market would make that decision, based on the price that they see, if that's your question.

COMMISSIONER KELLY: If we presume it all works the way we would hope it would, what will we do with the excess capacity that's in the market? Will we need another auction market? Will it be handled with bilateral contracts or should we not worry about it? Or will it all go in the energy market, or is it just an insurance premium, or insurance that's going to sit there?

MR. OTT: Essentially, if you're talking about the installed capacity reserve, which we had talked about and it's set at 15 percent, essentially it does become an insurance policy. If you actually think about this concept of energy-only versus capacity, there's another dynamic just beyond the fact that the energy-only signals might in fact, you know, be allowed to remain.

The fact is that as a society we have mandated reliability requirements. There's not a choice here. PJM doesn't have a choice, nobody has a choice; you must meet reliability requirements, period. The fact that we install those reliability requirements and put them in says by its very nature, this market again, as we said, will be long. And the price of being long like that essentially looks like an insurance policy. And capacity, effectively, is a call option on energy when you're short. Which looks a lot like insurance to me, although by no means am I an expert in all that stuff.

So the concept of capacity being an insurance policy, and each individual deciding for themselves, do they purchase it or not is really what this is about. Because I think the mechanism that is installed capacity provides that. What PJM's role is to set the standard, to say that this -- for reliability we need 15 percent. And the participants then would decide how they handle that. And if they buy excess, essentially they have the ability in what I'll call incremental auction to sell off their excess or adjust, and all other people to use it.

COMMISSIONER KELLY: And in determining -- you're informed by the States, I assume, the State's beliefs about what appropriate is, when you set the standard?

MR. OTT: As part of the setting of the IRM, you know in the stakeholder process discussions, obviously those discussions of reliability, metrics, et cetera, are debated.

COMMISSIONER KELLY: I'd like to talk about the timing of implementing a capacity market, RPM, whatever. With the four year forward-looking commitment.

Is the time to do that now, taking in to consideration the state of the transmission? Or is it better to focus on the transmission first? Or can it be done together?

In other words, are we going to be making four year commitments of the utilities, the load-serving entities are going to be making four year commitments that's then going to restrain the appropriate development of transmission?

MR. OTT: I believe you need to address both problems in the near term. Again, the way the RPM was designed, is the transmission plan comes out first, and that acts as an input to the capacity auction so that there's no ambiguity in the capacity auction about what the future intent, if you will, of long term transmission is.

And that creates again, a measure of certainty to the market so the market isn't trumped, if you will, by a large transmission bill they didn't see coming. Because again that would create a confidence problem.

So the issue of having a well-designed transmission planning process that looks into the future; and again as we said, further into the future even, is absolutely necessary. But equally as necessary is to show all the generation and the demand response and potential merchant transmission that may not be in the planning process itself; that there is a forward requirement here, and here's how it's revealed in price.

Just think about this if, we cannot possibly --

in other words, we have generation queues and a lot of forward planning in generation being done. There's no place that that's all coming together in a coherent information set for people to see how do they stack up?

In other words, say I built a very large line, and have plans to build that maybe to implement 2014. The point is generation; you may say well now you have seven, ten, twelve thousand dollars megawatts of generation, saying okay, I'm going to site on the sending end of that line. Well, if you put all that generation there and all the generation goes away in the East, even that line's not going to solve the problem, because the generation all went in the wrong place.

What RPM does is brings in and says "Okay, considering that line, here's the state of the system." And I may still need certain generation to support the receiving side of that line. And bringing that altogether in a package is essentially what's needed. And we need both of those.

As we said, we can talk about legs of a stool or whatever, but the problem is, we need to see both of those pieces of information or this isn't going to work.

COMMISSIONER KELLY: And then my final question is to ask you to comment on something that Reem brought up, which is, we could solve this problem by having an unmitigated energy market. Did you think about that?

MR. OTT: Yes, once or twice.

(Laughter)

Yes, we absolutely did think about that. And I think the critical element that really drove us away from looking at energy-only as a viable alternative is again the concept of, we require both operating capacity reserve and installed capacity reserve. So say we take away the installed reserve. So now I have operating capacity reserve margins, etc.

By the time the price gets to these levels we've talking -- okay, we're severely short. So by the time we get into emergency operations, the market is severely short. So by the time that signal got out, we have to live for three or four years of capacity deficiency we would call today, or the fact that we'd have to go into some kind of load shedding situation in real time operations; it's just untenable. The fact that we have these reliability requirements essentially mandates we have some mechanism to see on a forward basis the fact that we're going to be short. And energy-only really doesn't reflect that.

I think the concepts of, the unacceptability if you will of an energy-only market are also a piece of it. In other words, nobody has confidence that there won't be intervention. But by the same token, the fact that the electric industry mandates reserve.

That's another huge component, because other markets don't have that. Nobody's saying you have to have a certain amount of reserve of -- well, maybe they do of oil -- but the point is if you don't have enough, you just don't buy. In electric, if you don't have enough, you have a blackout and you have hearings.

(Laughter)

COMMISSIONER KELLY: Thank you.

CHAIRMAN KELLIHER: Does staff have questions?

MR. MEAD: First a question for Mr. Fields.

As I understand from your comments that you don't see a big capacity shortage problem in the PJM area. I gather you acknowledge that there's a current or impending problem in New Jersey and parts of Maryland, but not generally.

I guess my question is, and I put the same question to PJM earlier; in their view, the problem if nothing is done, is going to exhibit itself in the rest of PJM in the near future; we have an aging generation fleet, we have capacity prices and energy prices that are not very high and therefore are not encouraging additional investment.

What is it do you think about the rest of PJM that's different from New Jersey and Maryland that -- that the narrow problem is not going to expand into a broader one?

MR. FIELDS: Well, the point I was trying to make about the overall situation in PJM is that trying to match the solution to the problem. And our point has been that a lot of the solution of RPM shoots towards the problem of, if generators are taking the risk of investment from the beginning of their investment without a forward procurement, without a demand curve, that that's going to be a problem as far as getting investment to happen.

So we've looked at evidence as to whether that is in fact a problem, look to the global market, and haven't seen it.

As far as the local areas, one, it's very hard to judge at this point without a sufficient planning process, and that will not only meet these reliability criteria but go beyond that and enable competition throughout the region; and to broaden that competitive effect throughout everywhere -- not everywhere, but greater throughout the system.

Once that is in place, I think you have a better opportunity to see how prices are going to impact throughout local prices, either on the capacity -- we've talked about local capacity prices. Capacity and energy side to see how that happens over time.

And it's not a matter of just looking at historical prices. If you just looked at the historical revenue analyses that some people have talked about in the state-of-the-market report, there would be no reason to think there would be anything in the queue or there would be plants under construction or anything like that anywhere, if you just looked at those numbers. That's obviously not the whole picture; it's the future expectation of how prices are going to rise and people are going to respond.

MR. MEAD: As I understand it, in the Eastern part of PJM, despite the capacity shortage, general compensation is not adequate to encourage additional investment. Where would these price signals come from?

MR. FIELDS: Well, again that's -- I think you're referring to the historic revenues that have been produced. The question is, should we look at those historic revenues or should we look at -- or is the real thing to be looking at future expectations of revenues?

MR. MEAD: Let me try one more question on a different subject.

Ms. Fahey, we've heard some comments to the effect that RPM is not really technology-neutral. You know, it focuses on peakers and it won't encourage investment of base load units.

From your company's perspective, is that a fair comment, or not?

MS. FAHEY: The market will decide what's the right additional unit to build. So to the extent that someone believes that adding, let's say, a coal-based unit is justifiable because there's enough revenue in the energy market and whatever you get from the capacity market makes sense, then people will do that,.

Now PJM, unfairly I think, got a lot of criticism that "Oh, well, you built the demand curve based on a combustion turbine." Well, if they built it on a combined cycle or a coal-fired plant, the demand curve would be so much higher. So they got criticism that I think is clearly unfair.

Now there is an important policy decision to make; that do we want to incent baseload generation, and the States could very well do that. They could add a fuel diversity mandate, and I think PJM's filing has acknowledged that, that they said 'we're open to that'; and frankly, RPM facilitates that.

So to the extent that -- and they could do it state-by-state or zone-by-zone. So to the extent that a certain state believes that they don't have enough coal-based units, they can talk to PJM and PJM can add that as a location and requirement that we're going to clear the prices or maybe put that as part of the auction process.

So it's not that it can't be handled, it can; but they can't build the demand curve based on a combined cycle -- I mean, we would like that, but I don't think that would fly.

MS. COCHRANE: I had a question.

Andy, could you clarify the exit ramp thing? I guess as Reem mentioned, the demand curve, you set up based on price of new entry and then you also estimate what revenues a generator might receive from other sources, like energy and ancillary services, and that reduces it.

But you're still estimating it four years out; so if there are changes -- you know, how dynamic is the demand curve once it's established? Because on the one hand you want to have the certainty that you're giving, but then changes in the market could occur during those four years until you get to the delivery year.

MR. OTT: Right. Again, the concept of setting the demand reference, the administrative reference, essentially is very similar to an administrative price cap, essentially is what it becomes; is set at the cost of new entry of a simple cycle CT. And again, the basic reason for that, keeping with the concept of, we're trying to get a least cost solution to the reliability requirements is the least cost solution to capacity is a simple cycle CT.

But the concept of the feedback mechanism, that says we look at the historic revenue, okay, that comes for these generators. And again, it's looking at all the generators and their historic revenue, and it's looking at how those generators bid into the market.

The feedback mechanism, while I agree with you there is a time delay and again some of the time delays done in the analytics of Dr. Hobbs against -- create more certainty and less volatility. But again, over time as the energy market dynamic changes, the feedback does come back based on that historic analysis.

Of course it's not a very distinct or sharp feedback mechanism; because again just like with any design, you don't want to overreact to one year. But effectively the way -- and again, this can be a subject of debate; how should that feedback mechanism work? Is the one PJM posed exactly the right one? The answer may be No.

But I think the key here is, the key fundamental policy decision, a sloped demand curve to provide price certainty and stability versus not having such a mechanism I think is a real fundamental policy decision. I think it's a rate issue, to be perfectly frank, how you actually do the feedback and what's prudent.

MS. COCHRANE: So as far as the exit ramp goes, it would just trend over time, die out. It wouldn't collapse, as you said, but it would trend over time.

MR. OTT: There's two fundamental exit ramp features of RPM. The first, of course, is the feedback of the energy revenues which would essentially lower the overall demand curve. But second is, the demand curve falls to zero relatively quickly, as you get above capacity requirements. In other words, you have a 15 percent. It goes to zero by the time you get to 20 percent.

So if you have an area like we do, a fairly large area of the market that has excess capacity and maybe has the ability to transport capacity from other areas, very quickly its price falls to zero. So that's another form of the exit ramp or another way that if you start to have excess capacity it very quickly shuts down, the price shuts down to zero.

CHAIRMAN KELLIHER: Tatyana.

MS. KRAMSKAYA: I wanted to follow up on the question that was asked earlier by Commissioner Brownell with regard to what happens with generators if RPM is not implemented. And Ms. Fahey mentioned that 30 megawatts of capacity were retired recently because they were not needed for reliability. And yet this seemed to me somewhat of a contradiction, that even if RPM were implemented, it would seem to me that those 30,000 megawatts would not have been on line today because RPM would not address that type of capacity.

MS. FAHEY: And that's a key issue here, is that

RPM doesn't guarantee anybody anything. So to the extent that people do imprudent investments, or people go and overbuild and do things that are not logical or economically proper, they're going to pay the price.

So if somebody just goes and builds and overbuilds, the capacity price will collapse, and I think that's great, that's important.

And going back to the sort of, you know would we have retired these units anyway? The answer is we probably would have, because there is an excess capacity in the market. And within the region that we're in, the new units that were added are a lot more efficient. So it's just sort of the reality of the market.

Now again RPM is not going to guarantee that no unit would retire. That would be the horrible outcome. I mean, if a unit is not economic and it doesn't make sense to have it, and it's not needed for reliability, it must retire.

MR. FIELDS: Ms. Fahey, may I add? I think she's right. I think there's excess capacity. So we have -- retirements are not all bad; I mean, it's a part of the process of the market. And the exit of old generation units is good for us. It brings in new, more efficient units and we need to incent that. What we're not convinced is that the variable resource requirement will necessarily get the iron in the ground on baseload generation.

And while I recognize, I think what Andy's saying is it's going to send signals; but what needs to be answered is why didn't LMP set these signals? Why hasn't LMP done what we viewed it to be, intended to send signals. And it hasn't done that.

MR. JUDGE: If I could also add something on that question. I think one of the concerns we have about the demand curve is it could have that effect of keeping on generation that's not needed for reliability. If you look at the demand curve the way it slopes out to the right past the IRM, by its very nature as a supply curve comes up, you may be able to buy 15 percent reserves at $20; as a supply curve goes up it may intersect a demand curve at 17 percent at $30, if I kept my numbers straight. It will be a higher number.

That's added; the market or really the load is buying more capacity than it needs for reliability at a higher price, spending more overall dollars. The question becomes -- and that's keeping generation on line. The question becomes, is that worth it? You know, we have a lot of concerns that -- our position is that that's not worth it to load, buying that extra capacity; and it could have that very effect of keeping on generation that's not needed for reliability.

CHAIRMAN KELLIHER: Ask Ms. Fahey a question. You raised the issue of risk. Occasionally capacity market proposals are characterized as being designed to eliminate all risk for generators, to guarantee a profit or even a windfall, but most importantly to eliminate all risk.

Could you address that? Do you think you would be in a risk-free world if RPM were adopted?

MS. FAHEY: Absolutely not. I mean, what we're saying, if somebody wants to enter the market in an excess region, capacity region, and build their generation, the demand curve isn't going to bail them out. Just do the math, it doesn't work that way.

It's not about eliminating risk. I mean, this is a market. And we as investors will take on some risk in the market. But what the RPM proposal is doing is actually taking sort of the reality of what we have, which is we don't have uncapped energy prices, and they're saying on a very simple, fundamental basis, if I need a generator at 15 percent it is prudent that that generator make enough money in the energy and the capacity market to make a 12 percent return. That's really what the RPM philosophy is based on.

However, again, if people do not very smart things and they start overbuilding, then if you look at the demand curve, the capacity prices will, and you're not going to get that money.

So there's still some risk that's going to be borne by the investor, but it just lowers that risk. And it just makes it a lot more stable.

CHAIRMAN KELLIHER: And you control your risk currently if you believe currently you cannot build and operate profitably; you control your risk by simply not building.

MS. FAHEY: That's correct.

CHAIRMAN KELLIHER: You've been a very polite group, and we have a little bit of time. I just wanted to see if any of you believe that certain arguments advanced contrary to your position are exceptionally weak, and it would --

(Laughter)

VOICE: Or strong --

CHAIRMAN KELLIHER: Well, it's kind of point-counterpoint, our McLaughlin Group moment; but if any of you think, an argument that's contrary to your position is just very, very weak, hasn't been adequately demonstrated as such. It's not 24 different perspectives to help us and bring that out. That's not a very well diagrammed sentence if I had to diagram it, but.

MS. FAHEY: I would like to make a comment.

CHAIRMAN KELLIHER: Or is you want to pose a question to one of the other panelists. It might help us.

It might good right before lunch, too.

MS. FAHEY: Actually, I just wanted to make a comment in regards to what Mr. Fields said about Well, we don't like the demand curve because it may sort of buy capacity at 17 percent, and that's going to be most costly. And that's the exact opposite of what the demand curve does.

The demand curve says I will only buy more capacity at 17 percent if the total cost is lower. So they're not going to do that, and basically it's the intersection of the supply and the demand curve.

So fundamentally, and the experts are here just from a factual perspective, but that's not how the demand curve is put together. That's sort of the rationale behind it is that, if there is a little bit excess generation, you know, let's say 17 percent, having those extra units also provides competition in the energy market, because now you're not very tight at 15 percent, and ultimately they will also reduce energy prices because there's no competition among them.

So it's just the fundamental design of the demand curve, that you only buy more if it's cheaper, not because it's more expensive.

CHAIRMAN KELLIHER: Mr. Fields?

MR. FIELDS: Yes. I wasn't quite sure what issue I was going to talk about when you posed your question, but now I know.

(Laughter)

PJM has made the point, and I think Reem was echoing the point. It is true that if you look at the total cost of making purchases at two different points in the demand curve, the total cost of making a purchase at 17 percent on the demand curve is less than the total cost of making purchases at 15 percent of the demand curve.

The point I was making was that if you then compare that to the total cost of making, of buying 15 percent at the marginal unit at 15 percent, where the supply curve crosses 15 percent, you're going to get still an altogether lower number than either of those other two points.

So if you're talking about choosing which point on the curve where the market's going to clear, yes; you buy more, you get less total dollars. If you're talking about the difference between the supply curve of buying excess under the demand curve, and buying 15 percent at the marginal unit for 15 percent, in that particular auction it has to be a lower total cost.

And then you get into the arguments, well, is it a good thing for customers in the long to buy that extra capacity at those extra dollars? We haven't been convinced that is so far from the Hobbs study, and we've filed an affidavit talking about that and some other arguments made in the filing, that that is the case.

MR. TUBBS: In the first one when PJM did its presentation this morning there was a lot of discussion about demand response; and I think that the Pennsylvania Commission believes that PJM has ensured that demand response can participate in the RPM. However, by allowing interrupt load to be considered in forecasting, going forward -- it may not have minimal impact on price, the way the load or demand response can participate in the market. It seems like it may have minimal impact on pricing.

And then at the back end, demand and load can, three years prior to the delivery year, can opt out and get away from RPM cost. But we think there may be more need to have some more, and maybe as technology advances, that a load needs to have more of a dynamic role in price-setting.

The four year ahead commitment demand response really can't anticipate where it's going to be in four years. So we think that we need to have some more, perhaps having auctions closer to the delivery year or something to have demand have more impact on price.

CHAIRMAN KELLIHER: Alan?

MR. SCHRIBER: I'd just like to get back to demand response. Somebody is a little fuzzy to me. Demand response seems to me like it's something you can't manage, because it's a response. It's a movement along the demand curve.

So it's not clear to me what impact we can have on demand response, other than again shifting those curves, moving up and down the curve. So I guess I'm not clear on what the whole issue of demand response is.

MR. OTT: I think the real critical element is today we have certain types of demand response, and a lot of it we've seen in the market; it used to be called Alimony -- now there's some other acronyms for it. But the key is there are certain structures that have developed where demand can actually participate in the short-term markets; and while I will agree that that type of demand response that's already developed today, probably its best spot to participate is in the shorter-term capacity reconfiguration options as the IOR, which is a new acronym for the type of demand response we have today.

COMMISSIONER BROWNELL: No more acronyms.

(Laughter)

MR. OTT: Okay, thank you.

The key point, though, is that today's demand response is severely underdeveloped, we know that. The RPM, by providing a signal saying on a forward basis, if there's a way that you can have innovation, whether it be technological innovation or business innovation, and you say somehow I can sign up folks in advance who say "I'm willing to voluntarily opt out of this whole thing; if you tell me on a forward basis you'll give me a certain amount of money, I'll create infrastructure that allows me to exit the system when we have either high prices or shortages."

That's a totally new type of demand response, and we may or may not get it. But the point is today there's no business model, there's no forward signal, there's not to allow that. And while I can't be short-sighted and say that there's absolutely no way that demand response can't participate in these forwards, because I think they can. And I think that's what's severely missing today. That's why we have the atrophy; you know, it's not working.

I think the fact that I put a forward signal out and add that voluntary opt-out, if you will, alternative, I think people will respond to that, especially in the areas where they're going to pay $200 a megawatt day for capacity. That will create innovation.

I think the other piece of this, though, that you have to acknowledge, is we talk about this supply and demand curve intersection, and having the actual demand curve -- the point is today, if I look at the intersection of the 15 percent reserve margin and the marginal generator, if I do that today on a daily basis, effectively that's price suppression, because you're looking at a short-term capacity product. We're taking advantage right now of the fact we have excess, we're keeping capacity prices low on a daily basis because we're looking at these very short-term markets.

When you start looking at long term markets and allow direct competition by new entry, the fact is the supply curve will actually start to reflect some of these entry bids. The demand curve just acts again as a mechanism to put in a variable price cap and a variable penalty structure to make sure the market works, so we don't have to have all kinds of administrative intervention. So that's really what the demand curve is doing.

So its dynamic is not to create higher prices; it's to create rational prices. And rational prices on a forward basis. Because today we're as a community, we're living off the fat of the current system. And because essentially the daily prices are reflecting a 25 cent or a 30 cent capacity price, which is not reality.

CHAIRMAN KELLIHER: Yes. Mr. Stephenson.

MR. STEPHENSON: I just wanted to go back for a moment to the energy-only debate and some of the discussions around that.

I was left with the impression, after Andy spoke, that there's a believe that the energy market is incapable of sort of looking out ahead; that we are sort of structurally in the situation where a reliability issue is going to kind of creep us on us, and that we're not going to see that.

And I would submit that there actually is a forward market in energy, and that forward market, although it may not be as liquid as everyone would hope, is capable of providing signals that can incent and support longer-term generation investment.

So I guess I'm personally not willing to throw out the idea of energy-only just yet.

CHAIRMAN KELLIHER:  Mr. Young.

MR. YOUNG:  I guess along those same lines, and there are some big differences, some more small differences; but if my company could, and we probably couldn't, looking into those four markets, we wouldn't build anything as it stands right now.  And we have a pretty good balance sheet. It's too risky at this point to do that.

While we're sitting here without a crisis on our hands, or so we believe, I don't want to speak the bogeyman stuff, but I wouldn't want to be in this room if in fact nothing is done, five more years go by, we will have a crisis at that point.   And doing nothing I don't think is right.  Delaying further is not going to solve the problem. Getting on with it and doing something -- This is not -- you know, if I had to design it I wouldn't design this exactly;

but this was after five years of work, people got together and didn't all agree even on this, but I think there is potentially a looming problem that those four price curves are telling people about.

But the energy price now, even with historically high gas prices that's driving all this stuff, don't make the risk-reward calculation attractive enough for at least this generator to do anything about it, and I suspect most others as well.

So if it doesn't we're going to be sitting here a year from now still talking about it, and we're going to be a year closer to that really bad event.

CHAIRMAN KELLIHER: Thank you, Mr. Young.

Mr. Judge.

MR. JUDGE: If I could just follow up on his comments. And I think one of the problems you don't see enough forward prices in the energy markets is it's hard to get an energy-only market to recognize, fully recognize, the need for reserve margins. When it's an energy-only market, they basically see: Hey, if things are going well, t his price is sufficient enough. We you have to, for reliability purpose, fully recognize reserve margins. And the fact that two or three contingencies down the road, you'd need to have a system robust enough to handle

CHAIRMAN KELLIHER: Thank you. That's very helpful.

Mr. O'Neil, Dick, do you have a question?

MR. O'NEIL: We've had a lot of debate about the administratively-determined demand curve, and some people oppose it. And I believe, Andy, you said in the first session that all the alternatives are administrative determined. Because the only non-administratively determined, I believe would be if the demand actually expressed their demand and created a demand curve.

So are we just debating which administratively determined demand curve we're worried about? Not that there is an administrative -- we're only debating among the alternatives until the demand actually expresses what they believe to be the value of capacity. And I guess in that sense what Mr. Fields says is that you just don't see any reliability benefits beyond this sort of 15 percent number?

MR. FIELDS: No. I was saying that the added cost that the load would incur in buying capacity above 15 percent, we haven't seen evidence that that would be worth whatever reliability benefit it might bring.

MR. O'NEIL: But would there be some cost that the load would pay for reserves above 15 percent?

MR. FIELDS: Under, in what scenario?

MR. O'NEIL: Well, the magic number is 15 percent right now, right. Would you pay anything more for a 16 percent reserve margin, which would make the system more reliable in some sense.

MR. FIELDS: Right. I can't answer that question on behalf of load in general. That's an impossible question to answer. But what I can say is that there is a logical, rational basis to say we need 15 percent, we're going to buy 15 percent. If someone wants us to buy more than 15 percent, where's the evidence that that is worth it to them?

MR. O'NEIL: Well, the true evidence is that the load has to come forward and express what their value is. But as long as they don't do that, somebody's got to guess at what their, how they value those extra reserves. And it would seem to me just simple logic that there's some price at which you would pay for a little bit additional reserves.

MR. FIELDS: Well, I think in our comments, a protest actually, we looked at some under the current system; and I'm getting beyond my lawyerly expertise; but it's not -- under the current system, we've had excess capacity for a few years and we're getting a price. Actually you can see it in one of the charts that PJM put forward. You know, the price has sloped down over a yearly basis. It hasn't been zero.

In other words we are paying, right now, today, this year, we're paying a certain amount of dollars for capacity although we have a 23 percent reserve margin. We did it last year and in previous years.

CHAIRMAN KELLIHER: Mr. Fields, does having a 23 percent margin versus 15, is that of zero value or some value?

MR. FIELDS: No, I don't think it's of zero value; and apparently that price that has been paid over the last few years is a product, I believe, of the value of at least some consumers putting on that.

We don't know what the bilateral deals are, but if you look at the prices that have come out of the yearly markets, load bids in those markets, supply bids in, you get a price. So there is some valuation there that yes, we are buying more, we are valuing it, you know, it is being paid something.

MR. O'NEIL: So could I conclude that it's just which administratively determined demand curve we want to choose between, not whether? Because whether -- the non-administratively determined demand curve occurs when demand shows up in the market, that the people are consuming.

So we're just debating among which one we want to choose right?

MR. FIELDS: Well, I wouldn't parse words with you, but --

CHAIRMAN KELLIHER: You just say "Yes" then we --

(Laughter)

MR. FIELDS: Or I'll just say No, I don't know.

COMMISSIONER BROWNELL: You'll never give up.

(Laughter)

MR. FIELDS: I'll say Yes, I want to go to lunch.

CHAIRMAN KELLIHER: Okay. Good lawyerly response.

This is the end of Panel I, we have Panel II in one hour, roughly, 2 o'clock. The panelists at this and the other panels are welcome to join us for lunch upstairs. For the rest, I apologize, you'll be exposed to our own monopoly here at FERC, and you'll probably pay unjust and unreasonable rates --

(Laughter)

But we'll see everyone else at 2, and see some of you upstairs. Thank you.

(Whereupon, at 1 p.m., the conference recessed for lunch.)

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

(2:06 p.m.)

CHAIRMAN KELLIHER:  Why don't we close the door and start.

And thank you, panelists, for coming up.  Why don't we start.

Mr. Ott, you're on again?  Or you're on call.

MR. OTT:  I'm on call.

CHAIRMAN KELLIHER:  Okay.  Let's start with Mr. Sorenson then.

MR. SORENSON:  Good afternoon.  My name is Gary Sorenson, and I am the Managing Director of Energy Operations for PSE&G Power, LLC.

I appreciate the opportunity to appear before the Commission this afternoon to discuss PJM's Reliability Pricing Model.  On behalf of PSE&G Power, LLC, PSE&G Energy Resource and Trade, LLC, and the Public Service Electric and Gas Company.

The PSEG Companies fully support the key elements of the RPM proposal.  I will summarize them briefly.  The first key element of RPM is the forward procurement mechanism.  PSE&G believes that the proposed four year outlook will provide a much better signal for entry of potential capacity resources, and will strengthen the transmission planning process by providing much longer lead times for identifying capacity deficiencies in constrained areas.

The second key element is the locational capacity component. This is necessary to recognize the reliability benefits associated with capacity resources situated in transmission constrained areas. As I will discuss in greater detail later, if the current capacity construct had recognized the locational value of capacity resources, it is unlikely that PSE&G Power would have need to seek reliability, must-run payments in order to continue operating 836 megawatts of capacity in the PSE&G zone.

The third key component is the downward sloping demand curve used to clear the prices in the base capacity auction.

The PSE&G Companies believe the adoption of these key RPM elements will improve reliability by reducing fluctuations in the level of capacity reserves needed to meet established reliability criteria, and will improve the transmission planning process by providing a longer planning horizon.

The PSE&G Companies further believe that RPM will result in savings to consumers. RPM will enable capital formation needed by developers of capacity resources to occur at the lowest cost, and will help avoid the need for in-term RMR arrangements. Also, because RPM is designed to encourage the retention of capacity resources at levels greater than the bare reserve requirement, it should also result in lower energy prices.

The PSE&G Companies nonetheless believe that there is one element in particular in RPM that could use some work. As currently proposed, RPM could lead to premature retirement of older capacity resources in certain cases. The PSE&G Companies are especially familiar with the problems facing older generating units, because the generation fleet includes a number of older plants located within transmission-constrained areas.

In many cases, however, the physical life of older plants can be sustained for extended periods if the unit recovers sufficient market revenues to fund robust maintenance programs. When this is not the case, the units do not make enough, even to support nominal maintenance activities; the market is then telling the units they are not sufficiently valued to justify such expenditures.

If that occurs, the units may be operated in the harvest mode. This means paying minimal maintenance dollars, barely needed to keep the plant safely operating; and if even those dollars are not sufficient, the units will be retired.

In September 2004 PSE&G Power advised PJM that it intended to retire 836 megawatts of generation capacity.

Four of the units located at Sewaren are 50 years old; the unit located at Hudson is 40 years old.

The current provisions of RPM do not fully take into account the physical and economic characteristics of these older plants.

Under the RPM proposal, the owner of capacity resources that appears to be physically capable of operating the delivery year must be offered up by the owner. When plants get this age, to predict whether to still be operating four years from now, it's very difficult.

The one change we really like in RPM is the ability for units such as PSE&G's Sewaren and Hudson units to have a filed case here at FERC for full cost of service to be able to bid full cost of service in the RPM.

Full cost of service would not necessarily hurt the market. In the case of Sewaren and Hudson units, the rate filing was $33.5 million for 836 megawatts of installed capacity. If you assume the 10 percent forced outage rate, it comes out to $122 per megawatt-Day. They had an addition of $15 million of long term expenses, and still comes out only $177 a megawatt-Day, below the curve.

CHAIRMAN KELLIHER: Thank you, Mr. Sorenson.

Mr. Fitch.

MR. FITCH: Good afternoon. My name is Neal Fitch, and on behalf of Reliant Energy, I'd like to thank the Commission and Commission Staff for inviting us to speak on what is a vital and fundamental piece of good competitive markets.

I'm going to talk a little bit about who Reliant is, and then talk very specifically to the question given to this panel. Reliant is a competitive retail provider in PJM, and in Texas, as well as a wholesale generator across the country.

My company is very focused on equitable markets; we want to see markets that result in win-win situations. We don't want markets that are biased towards any particular entity, whether it be supply, load or transmission. And we're focused on creating a balanced and workable resource adequacy market that achieves the target reserve margin desired, as well as ensuring system reliability.

I think it's important that define up front what we talk about when we discuss resource adequacy. From my company's view, and I think from a lot of the discussion we've heard so far today many people would agree, it's strictly a long term product, not a short-term or operating reserve product. And frankly, it shouldn't be looked at as a financial risk management product. It is essentially there to ensure that you have the resources available to meet your peak load, plus some sort of reserve.

Now to the question at hand today, we previously discussed in this form and others five key principles that we think are required for any good resource adequacy market. I'll go through them very briefly here. To the extent you have additional questions, I'm happy to address them.

The first issue, which many people have spoken about, is that a good resource adequacy market must be sufficiently forward-looking. I think Mr. Ott made a very eloquent discussion this morning, as well as many others, on why this is so important.

You want to make sure you eliminate barriers to entry. Along with the desire to be sufficiently forward-looking, you want to make sure that resources may enter to serve the resource adequacy product. You want to ensure an enforceable design so that you don't have free riders, essentially; you want to make you have your reserves as required.

Obviously you want to accommodate retail competition, as retail competition continues to grow, you don't want to make market designs that could ultimately hinder that process. And finally, you want to ensure you have asset-backed and deliverable assets.

Now from our review of the RPM filing, we generally believe that RPM meets these principles, and while we believe that there are certain specific elements that can be improved such that RPM is perhaps more competitive in its nature, I think, and we believe that the record today is supportive of the Commission giving due support to RPM in a timely manner.

We would encourage the Commission to do so for three reasons. One, it makes significant and tangible improvements to an otherwise broken market. We had a very robust discussion this morning on how important these changes are, and the failures of the current market today. We think that RPM addresses these issues very succinctly.

Also fundamental to the market design is that it creates a great deal of certainty that frankly is not there for us today. For such a fundamental piece of the market design, right now we're not sure what it's going to look like in a year, in five years, what have you. So to the extent that this Commission can act, we eliminate that worry.

As I mentioned, I wanted to keep my comments brief. I look forward to additional robust discussion this afternoon, and we thank you for your time.

CHAIRMAN KELLIHER: Thank you.

Before Mr. Stoddard begins, I want to apologize to Mr. Sorenson and Mr. Fitch. I should have fully identified your affiliation and your title. I'll do that now, and then I'll do it for each speaker before you speak.

Mr. Sorenson is the Managing Director of Energy

Operations for PSE&G Power, of the PSE&G Companies, PSEG Companies, no '&'.

Mr. Fitch, Neal Fitch, is a Senior Regulatory Specialist with Reliant Energy.

And now Mr. Stoddard is Vice President, CRA International, on behalf of Mirant, NRG Companies, and Williams.

Thank you.

MR. STODDARD: Thank you, Mr. Chairman. Good afternoon, and good afternoon, Commissioners.

By way of background, I served as market design expert for suppliers in the New England capacity market hearings, and throughout the arduous but ultimately successful settlement talks.

Today I'm pleased to have this opportunity to discuss PJM's RPM proposal on behalf of Mirant, Williams, and NRG.

Like Gary and Neal, I believe the RPM proposal is by and large a very good market design. It will work with the existing energy markets to provide clear locational signals that will lead the market to build new resources and retain existing resources, when and where needed.

RPM includes two important features that will reduce cost to consumers: A forward-looking auction and a variable resource requirement, both of which add stability to the market, thereby reducing investor uncertainty.

After spending the last three months working through forward procurement issues in New England, I can attest the RPM approach is indeed a sensible and workable means to implement a forward capacity market.

Now someone proposed a wait-and-see approach to the reform of PJM's capacity construct, or advocate an energy-only market. Either would be an imprudent course. PJM's existing market is for all practical purposes an energy-only market with the result that the generation development queue is not sufficient to meet the region's near-term need for capacity, where it is needed most critically. And generation retirements are occurring in high growth area, despite the need for generation in those regions.

System-wide, PJM does enjoy enough generation reserves today, but areas of Eastern PJM do not. Parts of New Jersey, the DelMarVa region, and the Washington-Baltimore area are already approaching deficiency, as you heard from PJM this morning.

As I stated in my supplemental affidavit, this problem has been masked from the current capacity market by the integration of AEP and Dayton into PJM without any locational capacity price signal.

In light of the resource adequacy problem in parts of Eastern PJM, reform of the capacity market is needed this summer, as PJM originally proposed, not 2007 or later. It takes several years just to permit and construct a simple cycle combustion turbine, or to add major environmental upgrades to coal-fired generators.

Development of new base load technologies which are critically needed for fuel diversity will take even longer. Unless price signals are sent to the market now, it will be too late for competitive solutions to PJM's stated reliability problems.

Introduction of a locational price signal in the Eastern PJM is needed as soon as possible to incent the retention of existing capacity and the entry of new capacity resources. I prepared a chart which I hope you have I front of you that shows the average monthly capacity prices by quarter in PJM since 2002.

As the chart shows, following the integration of AEP and Dayton into PJM, at the time when we shift from the green bars to the blue bars, the average capacity prices fell. It was $32 a megawatt-Day in the third quarter of 2004, down to $3 in the third quarter of 2005.

Now by contrast, PJM's determination of the cost of new entry is about $200 a megawatt-Day. This disparity, along with the other evidence PJM has presented, highlights the need to introduce locational price signals in Eastern

PJM to address imminent reliability problems.

While strongly supporting the locational aspects of RPM, we are concerned about PJM's proposal to implement numerous small LDAs. Now on its face, the limited geographic size of the LDAs raises potential market power issues. This risk has prompted PJM to propose extensive mitigation that will needlessly interfere with the market. PJM has not demonstrated that there are in fact transmission constraints that would support the 23 LDAs it has proposed for the end state market.

Now I've analyzed the LDA proposal and believe the record supports the prompt implementation of the two LDAs that PJM had proposed for 2006, PJM West and PJM MidAtlantic. But only four larger zones thereafter, consistent with the major transmission constraints in PJM. For a detailed discussion of my analysis and the proposed LDAs, I refer you to pages 10 through 17 of my initial affidavit.

These two larger LDAs could be implemented relatively quickly and easily by simple modifications to the current UCAP mechanism; and the Commission already has sufficient record to support such a two LDA market.

In sum, Mirant Energy and Williams broadly support RPM, but believe it is vital for the Commission to take action so these two LDAs can be implemented now. We recommend the Commission resolve as many policy issues as it can, based on the current record, and that it establish further proceedings to address appropriately narrowed technical issues of the proposal.

CHAIRMAN KELLIHER: Perfect timing, Mr. Stoddard.

Next is Marjorie Philips, Vice President, Regulatory Affairs, with Constellation Energy Group.

MS. PHILIPS: My apologies, I'm with the Commodities group. I should have corrected that.

CHAIRMAN KELLIHER: Commodities Group. Oh, I'm sorry we --

MS. PHILIPS: It's my fault, not yours.

Good afternoon. Thank you for allowing me the opportunity to share the views of Constellation on RPM. Constellation Energy Group has four business units engaged in the marketing, supply, and delivery of power. Constellation Energy Commodities Group, mine, an active participant in the wholesale market, and we also market the generation owned by our affiliate, Constellation Power. Constellation New Energy, which is a significant new player in the retail business, and Baltimore Gas & Electric Company, which is a gas and electric distribution company whose transmission system is operated by PJM.

What I'd like to impress upon you is the service that our unregulated companies offer is expertise in managing risk for customers, including fuel and energy price risk, construction risk, and financial risk. And we do this through vigilant attention to the details of maintaining portfolios of assets whose value we deploy and optimize as we meet customers' specific business requirements.

We believe that efficient, competitive wholesale markets create the opportunity for us and for others to provide measurable benefits to consumers. Furthermore, realistic price signals for energy, capacity and ancillary services are the foundation of both efficient, competitive wholesale markets, and a reliable electric grid. These price signals can only be achieved by rigorous attention to the market structures that promote and ensure competitive market structures.

Let me start by saying that we filed in support of RPM. We believe that mitigated markets create a missing money problem, especially in load pockets, that must be fixed to maintain the reliability and competitive efficiency of the wholesale market.

RPM is designed to both capture the missing money, thereby providing necessary signals for the construction of new generation, new transmission, and demand response and promote reliability.

Constellation suggested some specific modifications that it believes would serve to enhance RPM.

The purpose of my formal comments right now, however, are to address two major issues that have been raised as potential flaws with respect to RPM, making it allegedly unjust and unreasonable.

First, that it does not guarantee investment in new generation; and second, it does not guarantee that more transmission will be built.

With respect to generation investment, no capacity market construct can ever guarantee new investment when and where needed. But it's clear that the existing capacity construct will not lead to new investment, and in fact may accelerate retirements, exacerbating the capacity shortage.

RPM at least moves the market in the right direction, by first and foremost establishing robust price signals for an energy market product capacity that has been demonstrably undervalued. Energy market mitigation has muted LMP locational signals. Thus, the locational component will encourage bidding to be built where needed most; that's in RPM.

Establishing appropriate and stable price signals is the foundation for creating stable market rules. This stability results from confidence that the market will provide revenue streams sufficient to cover investment cost plus a return. The variable resource requirement curve provides exactly the kind of supply and demand pricing information necessary to make an investment.

Together, RPM ensures the market structure for energy and capacity will provide the price signals necessary for investment. Finally, the demand curve helps smooth out the boom and bust cycle.

Market-based investment relies on confidence in our markets, and confidence can only be achieved through stability of market rules and the absence of regulatory intervention that undermines the value of those investments.

Similarly, RPM cannot guarantee transmission investments; but for the first time, it allows economic transmission projects to compete directly with generation projects, facilitating more efficient transmission decisions, allowing consumers to benefit from the cheapest winning alternative.

Moreover, the two should not be confused. If there's not enough needed generation, then all the transport capability is irrelevant.

I would like to leave you by emphasizing the most critical guideline that you should employ in your RPM deliberations or any other market design proposal that comes before you. The most critical feature of any successful market is the transparency and accuracy of price signals. Every decision you make should be weighted against this metric.

Does your decision lead to more transparent price signals that are a result of the genuine interplay between supply and demand, or not? We believe that the fundamental features of RPM pass this critical test, and should be approved by this Commission. Thank you.

CHAIRMAN KELLIHER: Thank you.

Our next panelist is Mary Ellen Paravalos, Director of Regulatory Policy with National Grid USA. Thank you.

MS. PARAVALOS: Thank you. Good afternoon, and Thank you to the FERC, and staff for the invitation today.

I will be talking around the role and form of effective regional planning, and questions about the workability of the competitive transmission component of the RPM proposal.

With regard to regional planning, the RPM proposal in and of itself is not sufficient to achieve the objective of assuring adequate, deliverable and reasonable priced resources to the PJM region.

Of critical importance is a robust transmission infrastructure to support both reliability and competitively priced energy and capacity. In fact, lack of such infrastructure has led us to the RPM proposal before the Commission.

PJM as an organization commendably recognizes that regional planning is an integral part of the discussion today. National Grid, however, suggests that a greater emphasis on actually achieving and implementing effective regional planning must be part and parcel of the RPM proposal, and that we must use this opportunity to implement necessary improvements alongside RPM implementation.

I would suggest that if PJM had its druthers, it would have preferred to have been in a stronger position years ago to have staved off our current vulnerability to load pockets and potential generation retirements.

What are these planning improvements? Robust planning criteria is fundamental; one that considers both reliability and economic benefits of improvements. PJM's current effort to move to a more comprehensive market efficiency analysis rather than rely on the limited unhedgeable congestion approach is an important effort to complete and implement.

However, we must ensure that PJM is in a position to work with transmission owners to identify small, moderate and large upgrades that may be necessary to avoid costly vulcanization, perhaps as many as 23 LDAs in the PJM region.

Time and timing is of the essence. We must position a region to be able to effectively plan over a sufficiently long time frame. Lead times for transmission, infrastructure improvements require this. In order to do this, the independent planning function requires scenario planning; looking up to 10 to 15 years out about likely developments in load growth, new generation sources, and generation retirements.

We can't wait for a knock on the door from a new generator developer here or a generator retirement there. If we do we will continually be running out of time to implement efficient infrastructure improvements.

On this note, it is important to understand the RPM's proposal of a two year window, after which capacity differentials would be input to the regional planning process. Particularly because the current PJM planning process already has a one year market window related to economic upgrades. We need to ensure that we don't unnecessarily wait up to three years to begin planning for infrastructure needs.

I would submit that an ideal structure to accomplish these objectives may be for one or two independent transmission companies that would be responsible for the region's transmission system and for identifying and constructing needed transmission improvements.

Independent of market interests, sufficiently wide-scale in geography, these companies focus on delivery of low-cost, reliable electricity through facilitating competitive markets. The advantage of such a structure is that it nicely cuts through the issues around conflicting utility business priorities, market interests, differences in approaches and even skill sets. And the further advantage is the ability to hold such an entity firmly accountable for both reliability and cost performance.

Given, however, the present construct of an RTO and several TOs, or transmission owners in PJM, we must ensure to the best of our ability that PJM is given the charge and tools to perform effective regional planning and hold PJM and utilities accountable to the greatest extent possible.

Lastly, we question the workability and propriety of PJM's proposal to encourage transmission infrastructure improvements via bidding into a capacity auction. We have questions around the workability of such a model, and also on the propriety of such a model. And around its flawed premise, that transmission should be treated as a competitive product. Transmission is not a competitive product; it is the critical infrastructure that allows markets to work properly.

In that the competitive transmission component of the RPM proposal is not an essential feature of the proposal, nor one likely to produce benefits, we urge FERC to reject it. At best, this element of this proposal is a distraction to the real business of adequate infrastructure; at worst, it potentially undermines an effective regional planning process.

Thank you very much.

CHAIRMAN KELLIHER: Excellent timing, as well.

Mr. Robert Weishaar. Is that the correct pronunciation?

MR. WEISHAAR: Yes, Mr. Chairman.

CHAIRMAN KELLIHER: With McNees, Wallace and Nurick, representing PJM Industrial Customer Coalition. Thank you.

MR. WEISHAAR: Thank you and good afternoon. My colleagues at McNees, Wallace and I have the privilege of serving as counsel to the PJM Industrial Customer Coalition. The comments I offer to day are on their behalf and on behalf of State industrial groups in Illinois, Pennsylvania, Ohio and West Virginia.

Industrial and large commercial customers are greatly concerned that the RPM proposal will result in significant wealth transfers from customers and their shareholders to power suppliers and their shareholders with little or no assurance that another layer of revenue will produce an economically and operationally optable mix of system resources.

Large customers' perspective is that investing in

RPM is throwing good money after bad. This panel has been focused on determining whether PJM's proposal would provide for just and reasonable wholesale power prices at levels that provide for adequate reliability or alternatively whether changes must be made to the proposal. Our short answer is that the RPM proposal is so conceptually flawed that even with modest modifications it will not produce just and reasonable wholesale power prices or provide reasonable assurances of resource adequacy.

At the risk of piling on to the concerns that were identified in the first panel, I will go through some Industrial Customer's primary concerns with RPM in its current form and as identified in our various pleadings and affidavits.

One, RPM aggravates the existing problem of severely overcompensating many existing generation resources without any return or benefit to customers for that overcompensation.

Two, RPM operates on the same philosophical concepts, locational payments and marginal clearing prices with no assurance that this additional layer of revenue will cure problems that LMP has been unable to cure in certain locations.

Three, RPM's proposed planning horizons will preclude meaningful demand resource participation; the four year outlook is just simply impractical for most if not all demand resources.

Four, RPM's centralized approach to resource adequacy will hamper bilateral contracting, much like LMP has handled large customer's efforts to engage in long term bilateral contracting in the energy market.

Five, a demand curve is an administrative approach to resource adequacy price formation that has in fact been proven to be capable of forming prices, but has not yet been proven to be capable of achieving resource adequacy objectives. And if the only answer to resource adequacy is to vest such administrative discretion in a central coordinator, then a central coordinator should be given authority to ensure that resource adequacy objectives actually materialize.

Six, if it is determined that the existing LMP energy payments are inadequate incentive to make long term investments, than any alternative approach that provides guaranteed payments to mitigate perceived risk of capacity cost recovery should be linked with an obligation to supply energy from units receiving such payments at actual marginal cost to prevent excessive returns for those units.

RPM is not a proposal derived from a thorough root cause analysis of what's causing the locational problems we're seeing. Some of which can be connected to our nation's inability to address the imbalance between supply and demand for natural gas. Only by coincidence will RPM do anything more than raise administratively-determined rates significantly and provide more reason for the public to increase it's well-justified doubt about the ability of electricity and markets to promote and serve the public interest.

The debate here today may be focused on a proposal known as RPM, but the discussion really begs the larger question: We, speaking on behalf of the folks who pay the bills and provide jobs, urge the Commission to recognize that there are much larger issues than the relative health of the ICAP piece of the PJM equation, and turn all attention to those larger issues.

In the meantime, and as a concession to reality, RPM ought to be put back on the shelf.

Thank you again for the opportunity to share with you the perspectives of PJM's largest customers.

CHAIRMAN KELLIHER: Thank you, Mr. Weishaar.

Now the Hon. Frederick T. Butler, Commissioner with the New Jersey Board of Public Utilities.

Fred.

MR. BUTLER: Thank you, Mr. Chairman.

Actually, it's Frederick F. Butler.

CHAIRMAN KELLIHER: Is it? I apologize.

MR. BUTLER: But that's only one of the surprises today. I didn't realize I lived in a red state.

CHAIRMAN KELLIHER: We'll correct the record on that.

MR. BUTLER: Anyway. I want to thank you for the opportunity to come here. The reason that New Jersey and the Board of Public Utilities thought it was important for me to come down was to express our concerns with the RPM proposal as currently constituted, and to tell you why.

But let me at the outset say to you that we realize, we know there's a problem. We in fact are ground zero of the problem, as has been mentioned several times today. We are doing some things that we think will help; we stand ready to implement whatever comes out of this process, because we don't want the lights to go out, we don't want to be the California, as it were, of the 21st Century, on the East Coast.

But having said that, I want to make six points with regard to our concerns with RPM.

One, RPM we feel needs to be fully integrated with the rest of PJM's regional transmission planning process. That point has been made repeatedly this morning by you and by others, both Staff and Commissioners; I'm not going to spend too much time on that.

Secondly, we don't feel that RPM provides an adequate opportunity for planned transmission upgrades to compete on an equal basis with planning existing generation resources, leading to the most cost-effective and reliable solutions. Again, that's been discussed this morning; I'm not going to spend a lot of time on that.

I will spend more time on points 3 and 4 of my statement, which has to do with RPM not adequately providing an opportunity for demand response to compete with planned and existing generation resources; or point 4, which is that RPM fails to address embedded cost inequities between the states.

Points 5 and 6 I will cover very briefly. Point 5 being that PJM does not have, it seems to us, sufficient time to properly address announced generation retirements under the current regulatory framework, which prompts the reliability problems in part, which PJM is attempting to address with RPM.

And point 6, explicit market power mitigation rules are necessary in any capacity construct that the Commission adopts.

Let me deal with points 5 and 6 very briefly, and then I want to spend whatever time is remaining to me on points 3 and 4.

Point 5, regarding the time frame for dealing with generation retirements or proposed generation retirements, this Commission accepted PJM's proposal to require only 90 days' notice before a generator retires and allow 30 days for PJM if the unit is required for reliability purposes, and 60 days to allow for a generator to file for cost of service recovery or form of the rate recovery.

We at the Board request that this 90 day requirement be revisited, because in our estimation it does not allow PJM to correct for liability problems that arise from announced generation retirements and result in cost-of-service rates for form of the rate recovery. And on point 6, I'm just basically going to say that in New Jersey, given all that we have been thru, all that we can see coming on the horizon, are very concerned about market power mitigation rules, and we think that any RPM proposal needs to have very strong rules to that effect.

Now let me spend some time on point 3 and point 4. RPM, we feel, does not provide an adequate opportunity for demand response. Demand response is assumed to be able to compete on a level playing field with generation and transmission. It is our believe that at the current time the demand side of electricity markets remain severely underdeveloped. We believe that demand response cannot compete with generation and transmission until it becomes fully functional. We think that it's very difficult to take the necessary actions to move greater numbers of ratepayers from fixed electricity prices to variable pricing signals. Such changes that need to be supported with advanced metering infrastructure, electronic data interchange, software and hardware, other technological support, and effective consumer outreach and education, all of which require time. And until that takes place, we think that there's a general disadvantage being given to demand side management.

We feel that the directives given to the States in the EPACT05 regarding advanced metering --

TIMEKEEPER: One minute remaining.

MR. BUTLER: -- will work towards that end, but more work needs to be done.

And finally, on point 4, that RPM fails to address embedded cost inequities between the States, we're an unusual place in New Jersey; we have the most densely populated population in the country. Our costs are higher, our environmental rules are stronger than in many other places, and those embedded costs cause generation to be difficult to site, and transmission to be as difficult if not more difficult to site.

And the time frames needed to get permits and the ability to build in a place like New Jersey is very difficult. We're concerned about how RPM deals with that;

we're concerned that we are an unusual circumstance within the PJM region, and we want, we ask that there be consideration be given to those concerns in developing an RPM proposal. Thank you.

MR. MOOT: Mr. Chairman, as General Counsel, I feel well situated to make a motion to give Mr. Butler a little more time to finish up, since so much of this is about New Jersey.

CHAIRMAN KELLIHER: Fred, do you need some more time?

MR. BUTLER: Sure. I mean, I can just take a little more time to talk about the relationship between RTEP transmission and the -- I actually pared this down so it would fit into 5 minutes; I don't know where to jump back in.

Our concerns are that there is a multiplicity of solutions to this problem, and that RPM as currently constituted, really does not give a level playing field to all of the possible solutions. That there's a time constraint, there's a time differential between putting in place transmission as compared to other solutions, like generation, especially given the nature of our region. There's a geographic, societal, environmental -- whatever way you want to describe it, constraint that New Jersey suffers under that makes it more difficult to come up with a solution.

And that demand response, which we have tried to implement, as a way to deal in the short term with this problem is really not at the same level of development, as it were, as generation deployment or transmission improvements, so that it can compete effectively in any auction for solutions to this problem.

I think that basically covers the points that I wanted to make. Thank you.

CHAIRMAN KELLIHER: And the last panelist is Mr. Seth Brown, Manager of Transmission Services with GDS Associates on behalf of the Virginia Office of the Attorney General.

MR. BROWN: Thank you, Mr. Chairman and Commissioners.

I have been engaged by the Virginia Office of Attorney General, Division of Consumer Counsel, for the purpose of analyzing the proposed RPM's potential impacts on ratepayers in VA. Although I am speaking today on behalf of Virginia Consumer Counsel, Consumer Counsel is also a member of the Coalition of Consumers for Reliability, and fully supports the CCR's efforts in this proceeding.

The Division of Consumer Counsel believes that RPM will result in unjust and unreasonable prices for both wholesale and retail consumers in Virginia, and that changes must be made. Consumer Counsel filed comments in this proceeding on October 19th.

Just to give you a little background, historically Virginia utilities were regulated at cost base rates. It's a non-market solution that yields certainty in rates and resource adequacy, and serves the public interest.

Generation and transmission needs were identified through integrated resource planning based on accepted industry and regulatory practices. Those needs were satisfied through a combination of self-build generation and transmission additions as well as bilateral contracting with other utilities and merchant generators.

The Virginia Restructuring Act currently provides that default service after 2010 will be provided at market based rates.

Less than two years ago, market integration proceedings for AEP and Dominion were held at the Virginia State Corporation Commission. As discussed in our comments during these proceedings, PJM represented that AEP integration would result in a modest decrease and the PJM wide reserve obligation, and quote "minimal impact on AEP's reserve margin."

Additionally, Dominion Virginia Power looked to the current capacity market design to forecast hundreds of millions of dollars in savings for Virginia ratepayers in future years.

Currently, Virginia utilities can meet the new higher reserve margins in PJM through of three options, or a combination therefore: Self-billed, bilateral contracts at negotiated prices, and capacity credits from the PJM market.

RPM, however, indicates unjust and unreasonable prices for Virginia ratepayers. Higher reserve margins for LSCs; that is, RPM proposes 16 percent, which represents a 2.5 percent increase since integration for AEP.

Two, administratively set prices through the VRR curve, based on costs of new entry for a single, specific technology. This ignores the diversity of fixed cost profiles between various technologies currently in service, including coal, nuclear and combined cycle.

It ignores the facts that baseload generators throughout the region are likely revenue sufficient under current energy and capacity markets. I would urge you to review the Synapse Energy Economics studies on RPM windfall profits that's available their website.

Three, no self-supply mechanism. All load and generation transact at a single, administratively-set price. The bilateral market will adopt these prices, and therefore no market negotiations will take place between willing buyers and sellers.

Fourth, the proposed opt-out mechanism imposes an additional reserve margin requirement of 3 percent. So for AEP, this represents an IRM of 19 percent, effectively more than 4 percent higher than preintegration when no significant load went unserved as a result of capacity deficiencies. In fact, RPM will require all load to purchase excessive capacity.

Fifth, only a single year's revenue stream for capacity is guaranteed four years ahead, and that doesn't guarantee that construction will take place.

The four year revision assumes that only intermediate or peaking capacity is necessary. This term limits both generation options and transmission solutions. There is uncertainty and potential for PJM to impose even more burdensome and costly reserve margin adders, and to alter the points on the VRR curve.

In the future, if the financial markets claim that the RPM one year commitment, four years out will not provide sufficient incentives to encourage the development of new generation. There will be a strong incentive and indeed precedent for merchant generators to request PJM and adjust the model parameters, to provide ever-increase capacity revenues in future years.

Finally, the Commission should reject RPM because (1) it results in increasing reserve margins in a capacity market; (2) it reduces the options for LSEs to meet their capacity obligations; and (3) increases currently adequate profits on baseload generation throughout the region in the name of cost recovery for new entrants in specific areas.

Thank you.

CHAIRMAN KELLIHER: Thank you very much.

Since Mr. Ott is sitting at the table, I wanted to know if he wanted to make any comments, if he wanted to respond to Mr. Brown, anything Mr. Brown said in particular?

MR. OTT: Yes, thank you, Mr. Chairman.

The concept of the RPM model again was to provide the capability for entities to opt to self-supply their own requirements in the RPM -- prior to the RPM options, essentially allowing them to self-determine, if you will.

There is a dynamic as part of that decision that involves the variable resource requirement in the ultimate load obligation they must cover. And we had actually created two alternative mechanisms for them to manage that. One is to actually have a variable self-supply; which means they'd essential gave a self-supply based on what cleared in the auction on a forward basis. They should actually be able to put in offers to say, should the auction clear at some higher reserve levels at lower prices, here's how I'll manage that forward risk.

There's also the opt-out provision which essentially says I have a long term IRP process that I've already created; I'd rather just use that. But the fundamentals of that, just as we discussed briefly this morning, are that any IRP process, you know, that we've been through in the past, looks at a reserve target plus manages risk; meaning they look at reserve target plus they also account for the fact that they could, load could grow higher, et cetera. So there is a bit of margin put into those. RPM is essentially just trying to replicate that process.

Obviously, again the fundamentals here, the fundamental policy decisions of, should we have forward commitments on a long term basis. Should we have locational and should we have these variable requirements I think are well discussed here. The details beyond the, you know, exactly how self-scheduling works -- obviously PJM is very flexible and would want to make sure that we capture adequately the way that gets done.

And certainly we're open to discuss that. They key, though, is it has to be equitable.

CHAIRMAN KELLIHER: Okay. Thank you.

I wanted to pick up on some comments that Commissioner Butler made, and with respect to New Jersey, particularly Northern New Jersey -- and I'm going to try to recapitulate your position; if I'm completely off, I'll hope you'll say so. But my understanding of what you said is that the -- if you look at reliability problem in New Jersey, particularly Northern New Jersey, that a transmission will necessarily be a larger part of the solution than perhaps elsewhere in PJM -- I don't know if you're saying it would be the only part of the solution, but it's a larger part of the solution than elsewhere, that entry of new generation in Northern New Jersey is either -- it's much harder, more expensive, and that the fact that transmission has to play a larger role isn't really reflected in the RPM.

MR. BUTLER: Yes, Mr. Chairman, I think that's a fair summarization of our position. I think all generation, whether it's in North Jersey or South Jersey, is constrained in terms of being deployed by some of the environmental concerns and the environmental restrictions that we have in New Jersey. But certainly that is a concern, and the density problem is an issue in North Jersey.

Because we have a lot of farms left in the western part of our State, and in the southern part of our State we've got the pine barrens, which in the middle of the southern third of our state, there's very little development that can take place.

So we're talking about generation that has to be in that northern half of the State, more on the eastern side and more near the New York Metropolitan Area, and it's very difficult to put generation there. We have a lot of retirements that are happening there because those are old plants, and we understand the economics of an old plant.

So therefore, transmission will be, I think, a larger portion of the solution that we can see happening.

CHAIRMAN KELLIHER: You raised some concerns about the RTEP process, and I forget which witness said that they -- one of you said it very politely, that RTEP -- yes, it was Ms. Paravalos.

MS. PARAVALOS: Paravalos.

CHAIRMAN KELLIHER: You were saying it might be undermined, that the RTEP process might be undermined by RPM. Are you saying that the RTEP process currently is effective, and it might be less effective or ineffective with RPM, or are you just being exceedingly polite in saying it's not really effective to begin with?

MS. PARAVALOS: I think that there is broad support for the notion that the regional planning process can be and needs to be more effective. My comment with regard to the undermining piece was with the introduction or reliance of transmission bidding into the capacity market as a competitive product; having both the infrastructure for transmission is sort of one foot in regulated model under the economic planning process and the other foot sort of as a market product. Our concern was that it would fundamentally undermine the regional planning process.

CHAIRMAN KELLIHER: Because you also think conceptually that's wrong, that transmission isn't competing with generation, what's competing is more remote generation is competing, and it would be facilitated by some transmission upgrade or expansion.

MS. PARAVALOS: I suggest that it's not useful to think of transmission as a competitor in this context. It is competition that leads to lower prices between supply and demand, and it is the transmission infrastructure that allows competition to really be competitive, to make sure that you have sources competing with one another, to make sure that demand response elements can affect those supply prices. If that makes sense.

CHAIRMAN KELLIHER: There's been some concern about regional planning and its effectiveness outside of PJM, and that was something that the Commission's State of the Market report showed last June, that it was ironic that the regions that have regional transmission planning were also, you were seeing the least expansion or the less investment. It seemed a little bit counter-intuitive that planning would result in less actual investment.

If you think there's a flaw in the RTEP process, what is it? Can anyone help us with that?

MR. SORENSON: I think you just hit it right on the head. When you do real planning and you tie RPM with the RTEP, you will build less transmission because you'll actually put things on equal footing. There is no sense closing competition between a low cost and high cost generator if they're $5 apart, but you have to build $10 in transmission to get there.

And when you do the joint planning, lo and behold, transmission is not always the answer. And unfortunately, people believe transmission is the answer, other people believe generation is the answer, people believe demand side is the answer. When you plan properly and you measure the dollars, you get the right answer.

CHAIRMAN KELLIHER: Okay.

MS. PARAVALOS: I'd respond that I think the regional planning in RTO regions has over time identified more and more investment that needs to get built. I think part of the problem in these regional planning processes is that they are focusing mostly on what's needed to minimally meet reliability standards and not doing the type of economic analysis that we need to get done to facilitate markets.

And so I would suggest that RTOs need to be better empowered to do this type of scenario planning, to look at likely developments of generation and load, and be able to get ahead of the ball by working with those transmission owners and other entities to start engineering, to start planning, to start some siting facilities so that when you get to a point where these system developments actually happen that you can pull the trigger on those construction upgrades and start the construction so that you're not always behind where you need to be in terms of getting infrastructure in place.

CHAIRMAN KELLIHER: Marjorie.

MS. PHILIPS: I wanted to expand on Gary's answer, and if I can pull a Reem, do a little, walk you back one step to tell you why I think the fears about RPM hurting transmission investment are grossly wrong. I think in fact it takes it a step forward.

This is why I want to take you back a second. What RPM is doing is it's treating a symptom, not the disease. The disease is market mitigation. You've heard people say that LMP is supposed to send locational pricing signals. LMP is not doing that, because precisely where you have load pockets where you should be getting these high signals, the generators are getting mitigated. And they're getting mitigated to their fuel cost, and as you heard, they're not getting much of a capacity cost.

So you have no accurate, transparent price signal coming out of these locational pockets. What RPM does is say "I'm going to make up for that missing capacity signal" and we talked in earlier panels that capacity is part of energy. You know, we'd all go to energy-only markets in a second if we thought they would be politically correct.

Capacity is a type of energy. Since we're not valuing it, RPM values it; it puts the value back into that pocket. And that way, now a transmission owner can do what Gary just said, which is "If I increase the transfer capability am I going to get adequately compensated?" And now I know the real price differences between moving generation say from Western PJM into New Jersey. Now that's a larger project, but even a smaller one, say outside of the DelMarVa peninsula where you might need a much shorter line.

This now gives you pricing information that we do not have in the market, and that's really critical. And that benefits customers, because it makes sure that right decision and balance between all these potential fixes to the market can be made with the best pricing information out there; that's what a market is.

CHAIRMAN KELLIHER: How about Mr. Fitch, and then Commissioner Butler.

MR. FITCH: Thank you. Complementary to Ms. Philips' comments in terms of price transparency, one of the things I believe that RPM does very successfully that doesn't exist now is, essentially has that information available on a forward basis for what units are likely to be around in the future? That doesn't necessarily exist today because generators have the opportunity when they are essentially uneconomic to leave the market.

Now transmission planners, generators, all market participants have a much better idea of what the future looks like because they've got this commitment in front of them to be there for a particular delivery year. Now that transparency, that price transparency is very important; not just for the generating side but also for transmission planners who want to expand and seek out ways to make a more robust system.

CHAIRMAN KELLIHER: Commissioner Butler?

MR. BUTLER: I just wanted to Marjorie's as always very succinct analysis of the situation that I'm not sure there is a price signal that would be sufficient to get a generator to come in and build a replacement to some of Gary's units up in Hudson an Carney. I mean, that is a monumental task to go through the process of getting permits, to cleaning up the existing sites, because you're not going to build it on an un-existing site now; you're going to build it where some of those units are closing down.

There's not a price signal that in our estimation is worth paying for the generators to come in and build in some of those. So we can talk about price signals and try to give the right price signals; I'm not sure there are some for some of these areas that we're talking about, some of the really constrained areas. And so maybe we need to perhaps give some sort of a boost to other solutions that are doable. Because you can all the price signals you want, all of the constructs you want; if it's not politically and sociologically doable, then it's not going to happen.

CHAIRMAN KELLIHER: Okay. How about Ms. Philips, since she was just mentioned; then back to you, Mr. Weishaar.

MR. WEISHAAR: Right.

MS. PHILIPS: Fred, the only problem or reason I would disagree with you is the only solution in a high cost area, is to get the money to whoever is going to improve that. And if you don't use price signals, which -- that might mean the price of RPM goes up very high, to incent people to build there because you need it, the only alternative is a reliability must-run contract.

And the problem with those is they completely mute and distort price signals; and that's exactly what starts to degrade a market, dare I mention we all know what happened in New England. And so you are caught -- New Jersey's in a bad situation, between a rock and a hard place. You're going to have to pay the money to get the generation there or the transmission built to get the generation there.

The question is, how are you going to pay it? We think it's superior to send a market signal as opposed to an RMR contract which leads to overall degradation of the market, long term.

MR. WEISHAAR: Thank you. Just a quick response to Marjorie's comments, and listening to the arguments on price mitigation was like Ground Hog Day. But Ground Hog Day was yesterday.

We went through this discussion in a proceeding before the Commission not too long ago, about the balance between market power, mitigation, and price certainty and scarcity pricing and so forth, and there was a settlement in that docket that was approved by the Commission.

So to the extent that was a problem, theoretically that is now taken care of.

CHAIRMAN KELLIHER: I think I should turn to my colleague, Commissioner Brownell.

COMMISSIONER BROWNELL: Well, it's a lively debate.

CHAIRMAN KELLIHER: It is. It is.

COMMISSIONER BROWNELL: And I just won't to follow up a little bit on that. Mary Ellen, you talked about a planning process that may be more independent and may and should be looking at short-term, moderate term, long term. And we didn't practice this, I want everyone to know.

Could you say a little bit about -- I understand how the independents work, of course PJM doesn't have any independent transmission providers. But could you talk about the short-term, mod-term, long-term strategy. And then I'd like to get people, particularly the parties who have said that they really have concerns about the planning process and the lag of the planning process to RPM. I'd like to get some comments as a response to this in the record, so we could take a look at this.

MS. PARAVALOS: I'd first like to clarify that our comments are not to be taken that we think that RPM is necessarily in conflict with an effective regional planning process.

In fact, the four year forward commitment, I think, can be helpful for planning. I think the fear is that we maybe tie the hands of the independent planning function and tell them, "Okay, only look at LMP signals when you determine when transmission is needed, or potentially only look at the capacity of these differential signals."

These signals can be helpful in a regional planning process, but they are not the only thing that the RTO needs to consider. It needs to broadly be able to consider, if they put an upgrade here or did a small or moderate upgrade here, does that overall help the economics of the system? Does it have reliability benefits.

I think it comes fundamentally to giving the independent entity enough freedom, so to speak, to really do long term scenario planning to broadly look at the economics and reliability of the system together, and to work with the transmission owners to be sure that folks are looking at the small upgrades, the moderate upgrades, and not just focus on the large upgrades.

So for instance, if you look at the regional planning process in New England, a recent RTEP report, their economic analysis really focused on "Well, you know what? We don't need any big upgrades here." You know, "the market is working well enough without these really large transmission projects.

But the same story is that I think that we run the potential of not looking at the smaller or more moderate upgrades.

I think having PJM be free to do economic planning will help. If people put bounds around it, conditions, that sort of thing, it starts to degrade the whole process and they're not sure what they can get cooperation from the TOs to build.

COMMISSIONER BROWNELL: And of course there are markets in which the TOs aren't the only people who do build, which might be an alternative.

MS. PARAVALOS: Correct, an alternative. But on the other side, that many upgrades to existing facilities may be the most streamlined and efficient way to do it.

I do worry a little bit about the potential for folks to rely on the market signals and the competitive bidding apartment of the PJM-RPM proposal, saying "Well, if it's economic, people will step up and respond to these market signals."

We heard that when we put in LMP markets; it didn't work. So that's our message, is the regulated transmission model works better, in our experience, than a market model.

COMMISSIONER BROWNELL: Well, I must confess, and we won't answer it here, but it is something to think about. We're creating artificial constructs to respond to mitigation because of the political pressures, and then we're mitigating the artificial construct because of the same thing.

And so at the end of the day, I'm curious as to how all the pieces fit together; but I think that's a question for another day.

Fred, I'm wanting to understand kind of what you're saying. I think we all appreciate the fact that New Jersey, for a variety of reasons, not the least of which is density, is unlikely to be the site of new generation or even major transmission. And yet, I don't hear you saying what Southwest Connecticut has said -- I don't know what they've said recently, but -- that they would like others to pay for the luxury of not having to build.

You're not saying that. You're saying you're willing to accept some accountability on pricing because you're going to rely on largely the neighbors. Is that fair to say?

MR. BUTLER: I think we're saying more than that. I think we're saying that we understand that there's going to have to be some things built. We just want some help in trying to make it happen, because what we see here is not, we think, going to make it happen.

I've got a couple of sites that would be great for IGCC; you know, clean coal. I don't know that anyone wants to come in and build clean coal in New Jersey with all they have to go through to get permitted and approved to build it. I've got two sites, frankly.

I've got sites that could support some other things, that I'm not sure anyone wants to come and go through all the tours, as my friends say, that it would take to build that in New Jersey. Same thing with transmission. We know we need certain transmission. I've got the stripes to prove that you can in fact site and permit and build transmission in New Jersey. We pushed that thing thru, it was a PJM-required transmission upgrade, and we put it through along the New Jersey coast, in some very developed areas that used to be pine forest and are now retirement communities. And now there's a 238 kV line down through there.

So we can do it and we will do it; we're not saying others will have to pay, but we're not saying that a generally-applicable process will help New Jersey solve its problem, number one; or number two, that if it comes down to it that we have to pay for every penny of this. If it's a transmission line that's coming in from oh, I don't know, West Virginia perhaps? We'll pay our portion of it, but don't expect us to pay the whole thing to get some power up to the load sector.

COMMISSIONER BROWNELL: Okay. I'd just like to add to your comment about demand side management. We've heard endlessly how demand side -- I mean, for five years it's the one thing I've heard consistently -- and yet we're largely relying on the States. We can do some things in the wholesale markets, but it would be good also if the States would comment on their status. I know we have some information, maybe we have sufficient; I don't know if David Capin in here, but --

MR. BUTLER: We will get you some, we will file it as a part of this.

COMMISSIONER BROWNELL: I don't know how to expedite this process. We've been supporting Madre, Rick Morgan is here; and I think the inconsistencies both in terms of deployment and the way states are approaching it are in and of themselves perhaps a market barrier. And I would encourage the States to get it. We can help, we can offer technical support, but largely it is a state jurisdictional issue, and I don't want to rely on it if it's simply impossible to do, and I think we need to be realistic.

But if it is impossible to do, then we're going to have to do these other things and develop markets without it.

MR. BUTLER; That's fair, and I think we can help with that, and we can get you some information if it helps you --

COMMISSIONER BROWNELL: That would be good.

MR. BUTLER; -- make a decision. Secondly, I think what we're saying is, don't just assume that because you put it into an RPM proposal as a, "oh, this is another path that can help solve the problem" that it's automatically going to be on equal footing, because it's just not because of the nature of it at this point.

COMMISSIONER BROWNELL: Trust me, I've been talking about demand side management in PJM since I was born.

Robert, I get confused about what the industrials really want. And you want energy markets, at least your natural association does; you want to participate in demand side markets, you don't really want price signals. You're not of the school that I increasingly am, which is "pull off the Band-Aid and just don't mitigate, let's let it rip." You're not there, are you?

MR. WEISHAAR: No, we're not, Commissioner. I think in terms of solutions and looking at where we are now.

Commissioner Butler's comments about we can price signal something to death in Northern New Jersey and not have a physical outcome trouble me. And it troubles my clients; and we're talking in RPM here the same concept that underlies LMP, which is if the price signals get high enough, there will be a physical solution to the identified problem.

We're struggling. Industrial customers in Northern New Jersey have been paying much higher prices than PJM Western hub now for a number of years; some in the form of implicit LMPs, some in the form of explicit congestion costs for those who are lucky enough to be able to find a bilateral contract. And those prices are, like I said, much higher than Western hub. Where is the money going? Why hasn't that extra payment over the time period since LMP implementation actually produced some physical response?

So in terms of solution, we need to get transmission right. We have been I think in reactive mode for a while. We look at short-term solutions. We rely on announcements, kind of unexpected announcements that major transmission projects are going to occur instead of anticipating that and actively planning for them.

We have 90-day notification for generator retirements, whereas in the past a utility would know years in advance when it's going to take a unit out of production, and what alternatives it needs to ensure reliability.

COMMISSIONER BROWNELL: So you're loving that old regulated market again? Wow.

Okay.

(Laughter)

I'm hoping that your customers in Northern New Jersey are working with the Commission and perhaps using their PAC checks in the legislature to make siting easier. Because what I heard was, you can send all the price signals -- that is what I heard, and nothing's going to get billed.

Fred said he's got some locations, but the rules are too tough, so maybe one of the solutions is help them change the rules.

MR. BUTLER; And before they go to the

legislature, let me just say that it's not necessarily them -- get them stirred up.

CHAIRMAN KELLIHER: Okay. Okay.

(Laughter)

MR. BUTLER; But it's also the 567 municipalities in New Jersey that stand in the way, because each of them has rules and regulations, et cetera.

COMMISSIONER BROWNELL: Well, you just consolidate those. That's what we tried to do in Pennsylvania; didn't work there, either.

Marjorie?

MS. PHILIPS: I hate to do Ground Hog Day with Bob, but I think it bears a little mentioning and it ties back to an earlier discussion. Which is, if you look historically at when generation has been built; let's look at the Midwest. That was in the Nineties when prices went for a couple days to $10,000. And boy, we all couldn't get in there fast enough.

So do price signals work? You betcha. Some of us are still paying the high cost that we had the herd mentality that we all built. Shame on us, but that's what happened. Price signals do work when they're not, you know, intervened with and interfered with. So that's the first thing.

The second thing, what you're hearing over -- and so PJM had a lot of new build in the Nineties and early 2000s, perhaps. If you look at mitigation, it has increased dramatically. Yes, prices have gone up, but that's fuel has gone up. We all know coal has gone up by 80 percent, gas -- Lord knows how much it's gone up.

Actual prices that we pay are mitigated, so we're getting -- you know, when you're generating, you just get cost plus. Whereas if you look earlier when the new builds were coming in, PJM was less mitigated.

What happens now with RPM is where there is overbuild, you're not going to get the capacity value, as everybody noted in the earlier panel. It's not a guarantee. What it will do is say where we're short, in these pockets of which unfortunately New Jersey is an extreme one; where we're short we are going to start getting the right price signals out to you, and that's where you'll see new bills and yes, that's where it's going to cost more.

But it's not where we already have a surplus; the capacity value is not going to change. So I do think price signals work; I think we do have some issues with LMP, and I'll stop there.

COMMISSIONER BROWNELL: I would also just like to add, for the record, that that overbuild was largely paid for by investors, and not ratepayers. And that was the first time that happened.

Now I feel bad for the investors, and surely they will not be there again for any of these solutions unless we get the rules right.

So Robert, and then we'll --

MR. WEISHAAR: I think Gary was next.

COMMISSIONER BROWNELL: I'm sorry, Gary?

MR. SORENSON: In Northern New Jersey you pay higher prices than you pay Western hub, that's a fact. The idea, the misconception that congestion and the difference in price between Northern New Jersey and Western hub has to be fixed is the whole fallacy here.

You pay a differential in price, there's a differential in the cost of land, there's a differential in the siting the plants, in the environmental constraints against us. But when you figure out that differential, what does it cost to condemn land through Bergen County to bring in a transmission line? That has a cost, all right?

Bob said he'd like to pay Western hub prices. Does he have any idea how much he would pay for the transmission to allow him to pay Western hub prices? If you do RPM, you put all these numbers in and the right answer comes out, and people start guessing that no one will build generation in Northern PS.

Commissioner Butler may be absolutely correct; maybe no one will build. But when you put in the cost of transmission, you put in the cost of a generator, and you look at what it costs you in congestion, you will get the right answer.

CHAIRMAN KELLIHER: May I?

If you wanted to respond to that, sure.

MR. BUTLER: Just in response; New Jersey customers have been paying higher rates than customers in West Virginia for a lot of years. Part of the problem we're struggling with is that the disparities increase and then the increase in the disparity is not going to physical solutions, and that's what we need to keep focusing on here.

We also have the problem where the differential is now butting up against reliability issues, and we all recognize I think that, from a political perspective, reliability always prevails.

So in addition to paying the higher differential for a number of years and an increasing differential, we're probably looking and in fact are now paying in the form of RMR payments, because at the end of the day, reliability will prevail and customers will be asked to cough up the additional dollars.

MR. STODDARD: I wanted, with your indulgence, to pick-up the retirement thread. There's been some calls for changing the rules or worrying about that. And just as RPM provides a more orderly build signal, I think it also provides a more orderly retirement signal. Units that have cleared an RPM auction and have taken on an obligation have taken on that obligation four years in advance.

If they want to step out of that position, they need in effect to find someone to take that position over. Once this market is in place, if a unit decides they want to retire, they're going to be doing this calculation years in advance. They'll be looking at their expected costs, their expected revenues in the energy, and they know what number they need to get out of the capacity market, to continue to operate as a unit.

If they can't hit that, they won't take the obligation. PJM will have the notice four years in advance, in effect, that a unit is planning on stepping aside, out of its capacity role. They will have, through the RPM, replaced that unit.

Now if someone decides in a closer-in period they want to retire, they still have the obligation to serve, and unless they can find someone to economically fill those shoes, they'll stay on until they can find a way for an orderly retirement.

So I think the market design, as I understand how Andy has got this set up, will solve many of the 90-day retirement problems that you're currently seeing.

CHAIRMAN KELLIHER: Mr. Ott?

MR. OTT: I think as we debate this and discus it, I believe we've had a couple commentaries about, again should we do this -- meaning transmission -- or should we have RPM as if again it's an either/or discussion. It really again is not an either/or discussion. I think it's absolutely critical that the transmission planning process be fully integrated.

We talked this morning about some of the aspects of that. Yet a piece of this, though, is if somebody can find a way to offer in, you know from a remote generator, a delivered energy solution into the RPM, why not allow it? It can only improve the capabilities; it can't be disruptive to the planning process.

Essentially, if the planning process itself is looking at reliability metrics, it's looking at over time, making sure we have enough transmission to serve the reliability needs, it also looks at the needs of a competitive market; and we have a long term, 10 to 15 year plan to do that.

Essentially those pieces are the metrics. The metrics, no one has said here, and most of all PJM, that we should fall back and use the RPM to drive the planning process; absolutely not. The RPM enhances the planning process and provides another alternative for transmission to come in and perhaps have a business model that's over and above these others.

So we need to keep that in focus, that that is not an either/or proposition; this is a composite integrated solution.

COMMISSIONER BROWNELL: Andy, I think we have that. I mean I think that's what people have said; but what they've also said is the RPM may enhance the planning process, but the planning process in and of itself needs fixing in order for that effectively to work together. That's what I heard, and I think that was the point the Chairman made before.

MR. OTT: Right, I was worried about the interruption of the planning process by RPM. I don't think that's possible.

MS. PARAVALOS: I did just want to respond a bit about, we've looked at the proposal, we still think that there are some elements of not being sure how a transmission product would competitively work in this process.

So for instance, if it was chosen for a particular auction, in subsequent auctions, does it have the opportunity to disconnect from the system? And if so, it's just hard to understand how that would work within an integrated AC system. So it's just in terms of how you price that market mechanism, what are the obligations of that market mechanism, does it cause operational problems when -- you know, these are things that I think need to be better defined, to make sure that it is workable and is not disruptive.

CHAIRMAN KELLIHER: Do Staff have questions they'd like to pose?

MS. COCHRANE: I have a question.

Andy, I was wondering if you could respond to some of the concerns about the number of the LDAs that you've developed, I think. I guess I've heard more consensus that there needs to be some locational aspect, and some have argued that we need to do that immediately and not wait for the RPM, but there seems to be a concern that you've kind of gone too far. And I was wondering what your flexibility is there.

MR. OTT: Again, the concept here is that the locational pricing, the separation that needs to occur should be driven by the physical reality of the system. In other words, if we see a reliability constraint in the planning process and on a forward basis, and we have a total import limit, if you will, into -- today, again, if we have a generator retire, we could fall below that critical limit.

What RPM would do is have that critical limit actually modeled in the process coming straight from the planning process. And RPM would say if, indeed I would have less generation in that area, which would violate the import limit, then the price would go up.

Again, it's very critical that that price signal, and the reality of that price signal be tied back to the physical engineering of the planning process. The fact remains that if we look at the actual result, we could have 26 LDAs. If you actually look at the results that we put out, most of the map is blue, which essentially means many of those import limits, although they have to be there and people need to understand that they're there, they aren't commercially going to be significant, and in fact you have large areas of the market develop.

So the key there again, just like the debate with LMP. The key is to put the right information into the process, to make sure that the pricing signals match reality. If we try to do otherwise, then we're going to be back here talking about the side contracts we need to fix the fact that the pricing signals didn't match reality, and I don't think that helps anybody.

CHAIRMAN KELLIHER: Mr. Stoddard?

MR. STODDARD: The concern of my clients is not that we -- we aren't trying to mismatch the physical reality. The concern is that the market power mitigation procedures need to work effectively with that.

If we look at each possible market area, and look at those as though there are pivotal supplies in there, we could end up having every bid into this market mitigated, which cannot serve the market well.

Appropriate mitigation, absolutely. Excessive mitigation, that's a problem. So we need to think about how those two pieces interact.

CHAIRMAN KELLIHER: Yes?

MR. SORENSON: Because we deal with these type of markets all the time, in theory you would agree with that, you wouldn't want to change the market; the LDAs are going to happen where they happen. This is the same argument when people told you, "Don't give us LMP, let's just divide it up into groups like we know what's going to happen. We really don't need all these nodes to be priced. We'll just pick some."

Well, you can't pick some. And guess what, when these LDAs are small enough that you have to mitigate them, you have to mitigate them. You can't do LDAs to make the market look good if that's not the area that's constrained. You have to follow the physical aspects, and if the generators have to be mitigated, they're going to have to be mitigated.

CHAIRMAN KELLIHER: Thank you.

MR. MEAD: Two questions, actually. First for Andy, and then perhaps others may want to chime in.

First of all, do you imagine that there may be very local areas, you know, downtown Philly or someplace -- where your LDAs just aren't granular enough to send the price signal to address any particular very local capacity problem. And if so, what would be the solution?

MR. OTT: Again, in the models that we've run, when you see these larger area constraints that in a capacity sense tend to come in and bind, which essentially shows those prices for capacity go up. A lot of those areas today where we have the concept of frequently mitigated units, which have been lovingly discussed throughout these processes.

Some of those units have very localized voltage problems, et cetera. But the larger area constraints tend to dominate in capacity, so it tends to bring their capacity revenues up. So we get away from those frequently mitigating debates, because now the larger scale constraints actually tend to dominate, from a capacity import point.

So the actual in-practice, the localized voltage limits tend to be more energy-related, and the broader capacity import limits tend to be the ones you see in capacity.

So I think although theoretically it's possible you could have some of these very small LDAs, and in fact you may get one of those; I think the reality is that in most cases you'll see the more, the zonal or super-zonal, if you will, that will actually be practically binding.

I think the answer, by the way, to the question is what if we get one again, would essentially be that the -- the capacity price in that area of course would go to the cost of that unit, and effectively would be a transparent RMR contract. Everybody would see it so you could compete it away, but effectively that's what it would become.

MS. COCHRANE: Just a follow up so I can understand. Sort of like my other question earlier with the demand curves. How dynamic would these determinations of the LDAs be? Because you were saying that they are going to match up the system realities, but then also you're going to be making changes to your system, and hopefully relieving congestion and things like that.

Do you see the LDAs, in each auction, maybe the configuration would change? Or how would you --?

MR. OTT: Again, the reality, obviously with locational pricing and energy, the energy clearing every five minutes, is quite volatile, and the congestion, and somewhat unpredictable. In the capacity planning world, though, where you're looking at really more installed reserve margin, peak loads and that type of deliverability analysis, those tend to be more sustained problems, and we don't really see a lot of volatility in, one constraint's in one year and out the next kind of deal. It's not quite the same; I mean it's more of a long term look.

So the reality of it is, the volatility of an LDA coming in and out or having LDAs change shape really isn't what we're seeing. If you actually look at the simulation results; again they were only shown graphically with color, which aren't seeing wild changes in shape, you're seeing more gradual trends, and I think that's really more the case here.

Again, the concept there of defining the LDAs based on the planning process; if we find that the LDAs are to fluctuate wildly in that planning process, then obviously there's an issue with how the forward planning is looking to various metrics, and I don't think we've seen that. We've actually seen more consistent results.

MR. MEAD: One more question. To Andy. On the subject of mitigation, as I understand the rationale for the four year forward idea is that it's far enough in advance that you can rely on new entry.

If you can rely on new entry, why do you need mitigation?

MR. OTT: I think they're very similar to some of the discussions we've had on scarcity pricing. I think if the area is broad enough, meaning the area we are talking about is broad enough you probably don't because you have reasonably competitive solutions; meaning you could have a different site solve the same problem.

So I would think that as we move forward and discuss in detail some of the actual mitigation features, the fact that you have the new entry coming in to directly compete -- again, it really acts as an implicit price cap. And I think part of the issues surrounding the, you know having the demand curve and having that flexibility for a new entry does in fact get away from a lot of the mitigation that's necessary.

The actual facts, the details of the mitigation I think we can discuss.

MR. MEAD: As I understand part of the mitigation, there's a structural test or two that looks at a number of competitors. Is the idea that you would consider new entrants or potential new entrants in, among the entities that are competing for calculating pivotal supply --

MR. OTT: Absolutely. that's part -- that's why you do essentially that data gathering in advance. And those potential new entrants would actually be part of that equation.

CHAIRMAN KELLIHER: Any other questions from Staff?

All right. Thank you very much, panel. Really appreciate it, it's helped a lot.

We're going to call the third panel up.

Thank you, second panel. Have a good weekend.

(Pause)

CHAIRMAN KELLIHER: Let me introduce the panelists in the third panel

First of all, Mr. J. Craig Baker, Senior Vice President, Regulatory Services with American Electric Power Service Company.

Second Mr. James Sheffield, Vice President, Morgan Stanley Capital Group.

Third, Mr. Edward Tatum, Assistant Vice President, Rates and Regulation, Old Dominion Electric Cooperative, representing the Coalition of Consumers for Reliability: and

Fourth, Mr. Thomas Hyzinski, Manager, ISO Markets Development and Regulatory Policy with PPL Parties.

And last but not least, in actually the prime cleanup position of the day, in the prime rebuttal position on the panel is the Hon. Arnetta McRae, Chair of the Delaware Public Service Commission.

Thank you all for coming here, and spending Friday afternoon on RPM with us.

So Mr. Baker, why don't you lead.

MR. BAKER: Thank you.

The questions of capacity margins and adequate reserve resources in PJM market is a tricky one. I have a story to tell that I think helps perhaps explain AEP's position:

A man tells his doctor that his wife is losing her hearing, but she refuses to seek medical help. The doctor tells the man to go home and ask his wife a question as soon as he walks in the door. Then he should walk a little closer and ask the same question. He is to come back and tell the doctor how close he had to get before she could hear.

So the man goes home, and he says "Honey, what's for dinner?" No answer. He repeats several times. As soon as he's within three feet of her and he says "Honey, what's for dinner?" she shouts back: "For the fourth time, we're having spaghetti."

(Laughter)

I understand how she feels. The current deregulated region within PJM does not appear to provide adequate generation resource availability. But maybe the accusations of deaf ears have been made to the wrong parties.

AEP hears the need to address it, but we do not believe that we are the ones who need to take corrective steps. PJM's Reliability Pricing Model --

CHAIRMAN KELLIHER: Are we the husband in the analogy?

(Laughter)

MR. BAKER: We'll get to that later.

PJM's Reliability Pricing Model has been proposed to address three basic shortcomings in the current market design. It does not look far enough into the future; it lacks a locational element and does not provide sufficient financial incentives for supply editions. The RPM attempts to address these shortcomings, in our opinion, with command and control regime administered by the RTO.

Frankly, these are the same concerns of the AEP states. We work with our state regulators to plan for our customer's generation needs far into the future; we built to meet the target reserve margins now set by PJM, consideration locational transmission constraints, and our financial needs are met through generation rates established in regulatory proceedings.

This is clear by our planned filings with regulators to build two 600-plus megawatt IGCC base load facilities. The shortcoming that exists in states with complete deregulation of generation are not the same concern for us meeting our load responsibility. The RPM simply imposes additional cost on our customers.

PJM has offered a capacity resource plan, but this falls short of the mark by unfairly penalizing entities that may wish to exercise supply option and also results in a higher cost by preventing customers in other regions access to available low cost generation.  AEP believes the goal should not be 'one size fits all' administrative situations, but the availability of low cost, reliable generation.

That is why we filed, with our comments, a long term capacity opt-out option.  A fundamental tenet of our alternative is that load-serving entities should be able to submit a long term capacity resource plan as an alternative to the RPM, and as such avoid the vagaries of the auction process.

The AEP self-supply option has a variety of merits for LSCs, in particular recognizing that vertically integrated utilities continue to operate in retail-regulated states.

Here are the key advantages:  AEP's option meets the PJM's 15 percent reserve reliability margin requirement without the incremental financial exposure of attempting to achieve the 16 percent in the capacity auction.   AEP's proposal can be an option for all LLCs regardless of whether they operate in a regulated or deregulated state.

The AEP option allows entities in regulated states to communicate with their Commissions on long term planning.

I would like to take a moment to emphasize the importance of transmission and the recent strides that PJM staff and stakeholders have made on a long term economic planning approach. This has the potential to address capacity shortage issues in the entire PJM footprint without the additional cost inherent in the RPM plan.

Further, by balancing generation and transmission approaches to serve capacity problems, PJM will more likely arrive at a least cost solution that may also minimize long term energy costs.

AEP believes that the alternative approach more equitably addresses the capacity planning needs of the entire PJM footprint, and does not force a solution in search of a problem.

Remember, just because the man knows what he's having for dinner doesn't mean that he's addressed the entire dilemma.

Thank you.

CHAIRMAN KELLIHER: Thank you very much.

Mr. Sheffield?

MR. SHEFFIELD: Thank you for the opportunity to come here today and speak on this topic. Clearly PJM is doing many things very well. This is self-evident because they have created the preeminent electricity market.

This presentation will focus on Morgan Stanley's concerns and alternatives to the proposed Reliability Pricing Model.

We're very much in agreement on the goals that we're trying to reach, specifically to attract and sustain needed capacity; to protect buyers from extreme price volatility, and to provide ultimately reliable service at a lowest cost.

To meet these goals, we believe that an ICAP-like structure is not necessarily the best answer. Specifically, ICAP structures are not the best way to provide confidence to investors that consistent revenue streams exist. They don't do the best job of promoting -- or actually, they don't promote or require long term contracting or hedging by LSEs to protect themselves from volatile market prices. They do not necessarily foster the right mix of investments in the right locations, although locational marginal pricing is certainly a tool that does do that, and we strongly agree with that.

They do not necessarily produce efficient outcomes, nor do they reflect the wide disparities of the value of lost load or provide the correct price signals for load response. And therefore, they don't allow customers to exercise the choice or the trade-off between reliability of service and cost.

Our feeling is that the best way -- well, ICAP solutions do not represent market based solutions, and they do not let the market work to its fullest. And ultimately they do not therefore provide reliable electric service at a lowest possible cost.

ICAP-like market designs are not the answer because they do tend to do the following: They do tend to distort price signals. They do have a tendency to create higher prices, due to either insufficient generation capacity or excess capacity from uneconomic investment.

They tend to create revenue streams perceived as being strongly influenced by regulation, and therefore vulnerable to regulatory revision.

The required administrative central planning that is reminiscent of cost-of-service regulation, and they reintroduce the potential, therefore, for stranded costs.

They require a regulatory process to determine the type, the amount, the location and the characteristics of capacity. This is reminiscent of the failed regulatory model all over again.

The market design that combines uncapped spot market prices with forward contracting requirements to hedge the risk associated with these uncapped prices has the following benefits: It's efficient and it lets the market work. It pretends to provide accurate price signals, recognizes the vital role of price volatility in an efficient market, and provides price stability through forward contracts for those who need it.

It will tend to bring about optimal investment, both in level and in mix and in locations. It properly values and therefore maximizes demand response participation. It creates a liquid and transparent long term forward market that reduces risks for investors in new plant. It provides necessary revenue streams to attract and sustain necessary investment in existing generation facilities.

It greatly simplifies, but does not eliminate, the regulatory processes. It fosters long term forward market development. Similar constructs have been implemented; in Australia, the U.K., Alberta, and are now being considered in the United States in Ercot and in MISO.

From our perspective the choice is relatively simple: What we are proposing is a fairly simple construct. Remove price caps and continue the process of forward contracting that has already begun, to hedge exposure to the potentially high market prices. That is to continue to advance a preeminent market-based structure using market-based principles or take a step backwards and move in the direction of regulatory central planning. Thank you.

CHAIRMAN KELLIHER: Mr. Tatum.

MR. TATUM: Thank you very much. I'm Ed Tatum with Old Dominion Electric Cooperative. We are a member of the Coalition of Consumers for Reliability and a supported of the enhanced Integrated Transmission Capacity Construct that we like to call ITCC -- sorry for the acronym, but it's easier to say.

CCR strongly believes an alternative to RPM is essential to ensure continuation of a robust capacity adequacy construct in the PJM footprint. There is adequate and compelling evidence that the current construct has attracted significant new generation investment when there was a surplus of capacity.

There is evidence that generation siting decisions are complex; we've talked about that in our earlier panels; they take into account a wide variety of variables, and that an inadequate generation grid is a high barrier to entry for new generation investment.

The majority of capacity transactions under the current construct have been long term and have been bilateral; over 92 percent are outside of the spot market. Of course there's always room for improvement as the market evolves and experience increases; all of the changes to the PJM market have been evolutionary, and we feel this is no different.

It's crucial, however, that changes to the capacity construct truly enhance the construct, and did not allow ourselves to be distracted from the core issue that must be addressed if we're to complete our journey into competitive marketplace, and we need transmission.

There's a lot of activity right now at PJM, and a lot of activity before this Commission that has the potential to address these transmission issues; but even so, unless they're resolved, and we are committed to addressing the dearth of transmission investment, we're in peril of being sidetracked by those who will benefit from the minimalist reliability-based planning that we currently have in place. And reliability-based planning was appropriate when we were in an integrated resource planning environment. But as generation and transmission at that time were bundled and under the control of a single entity, there was a good level of control and certainty of outcomes.

The reliability-based transmission planning that's employed today worked well in that paradigm, but that approach does not work in a competitive marketplace. We must change our approach to planning the grid, recognizing that generation is now competitive, and we can no longer rely on the control and certainty of their behavior to plan the grid.

So we must all keep our eye on the ball, recognize old ways of thinking that can derail us; and even PJM with their strong commitment to revising the transmission planning paradigm must be vigilant to not be distracted.

In their filing letter, PJM correctly states, quote: The current planning process is biased towards transmission solutions. End quote. But the solution is not to restrain that process. And very respectfully, I submit that we need to set aside the myth that regulated transmission assets are competing with generation, and we need to move on from that. Generation and transmission do indeed interact.

We must make sure there's an adequate amount of T in our RTO; and PJM needs the Commission's help and resolve to ensure the transmission planning and construction issues currently before the PJM and the Commission are fully and correctly resolved. This includes planning for generation retirement; we should not be surprised that a 50 year old unit may retire soon.

So transmission is important, but beyond that, only incremental changes to the existing construct are warranted. If you properly address the transmission, then you can look at incremental changes for the capacity market. And at CCR, we do believe there is a need to address local aspects of the capacity construct. It's not unreasonable to expand the commitment period, and we've proposed to expand it from one day to one year, and I hope everyone agrees that one year is significantly longer than one day.

We need to revise the capacity adequacy assessment to set reserve margins; not one, but three years in the future, and a reasonable clearing horizon should be established. These rational, evolutionary and incremental changes will enhance the construct to provide relief to generators who are truly unduly burdened, solely due to the evolution of our market.

Additional changes, however, would not be prudent given the data to the contrary, and will sidetrack us from the important task of getting sufficient transmission built.

ITCC is not just a transmission proposal. In evaluating changes to the capacity construct, we believe the focus of the debate should be on reasonably defined resource obligations which markets have generally done in the past and will in the future clear, as opposed to some discussion of what is a reasonable revenue for a narrow group of merchant assets. And we also think the debate should be on dealing with exceptions as exceptions and not systemic issues -- unless we wish to consciously move from market-based to administrative solutions, which I don't think we wish to do, then individual participants should manage their own obligations and risk, and prices should be set by the voluntary interaction of willing buyers and sellers. ITCC allows this, but we do that without a demand curve.

As near as we can tell, based on the information we provided for the PJM market, a demand curve is not a good policy decision, and individual participants that being they can do so better with long term investment can do so in that market today.

I appreciate the opportunity. I'm out of time. I remain available for your questions, thank you.

CHAIRMAN KELLIHER: Thank you, Mr. Tatum.

Mr. Hyzinski.

MR. HYZINSKI: Thank you for the opportunity to be here today.

As you know, PJM continues to advocate RPM as its long term adequacy solution. PPL has carefully analyzed RPM and concludes it is an administrative, non-market solution that simply will not work.

RPM's mandatory four year forward auction will interfere with or eliminate both short-term and long term bilateral markets for capacity. PPL has suggested several ways to fix RPM that would make it a more market-oriented approach and would allow for bilateral contracting, but these suggested fixes haven't exactly been embraced by PJM.

Like you, PPL has been searching for some way to resolve the ongoing debate between those favoring the PJM - RPM proposal and those who believe it is seriously flawed, and will fail. We think we have found a possible resolution.

The Commission should consider adopting an energy-only market in PJM alongside RPM.  We have been studying the work of Professor William Hogan and the Midwest ISO, and believe that work has a great deal of merit.

Professor Hogan and MISO describe how energy-only markets will achieve the optimal level of investment in generation and demand response without the need for extensive administrative structures such as proposed in RPM.

It is important to note that an energy-only market is not a free-for-all with $10,000 price spikes and boom or bust cycles of investment where consumers are left unprotected.  Rather, an energy-only market as described in the other materials I am submitting today provides proper incentives for load-serving entities to act responsible to protect themselves and their end-use customers from the full impact of price volatility.  By using long term contracts, self-supplied generation, and financial hedges.

State regulators can oversee the reliability and hedging requirements.  PPL believes these incentives are the key to creating the necessary environment for bilateral contracting and efficient new investment.

Proponents of capacity mechanisms like existing ICAP market or RPM claim that an energy-only market will not provide adequate long term resource adequacy.  They do not trust market mechanisms to provide the appropriate incentives to both buyers and sellers to produce the right mix of resources in time to meet demand.

They do admit that the existing situation creates a missing money problem, and some of them argue that the higher energy price cap exposed consumers to higher spot market prices. But market proponents like PPL also recognize that higher spot market prices provide the incentives for load to hedge, and for generators to perform well.

PPL and other energy-only market proponents also believed that replacing the missing money through capacity-based systems actually creates a disincentive to short-run operational reliability. Further, if the capacity-based system of choice fails to replace all of the missing money because of an improperly constructed demand curve, or because of excessive market mitigation, it will lea to insufficient investment in long term resource adequacy.

To resolve this debate, FERC must permit an energy-only market to work in parallel with PJM's RPM. The Commission should require PJM to raise its $1,000 price cap gradually up to the value of loss load, simultaneously with the implementation of RPM.

If PJM is right, and RPM produces sufficient new generation in the right places and of the right type, then scarcity pricing signals that would occasionally be produced by an energy-only market will be absent or rarely experienced. Rather than relying on forward contracts to secure resource adequacy, resource providers and LLCs would rely upon the RPM auctions.

The energy-only market can remain safely in the background with little impact on RPM. And if Professor Hogan, the authors of the MISO paper and PPL are wrong about the ability of an energy-only market to encourage the necessary new investment, then RPM will function as a back-stop to ensure that adequate peaking generation is built to meet PJM's reserve requirement.

However, if PJM is wrong and PPL, Professor Hogan, and the authors of the MISO paper are right, RPM will fail to incent construction of new resources. Then the higher energy market caps of an energy-only market will assure that there is no missing money, and will encourage both investment and long term contracting between resource providers and load.

Over time, RPM's net revenue offset will prevent overcompensation of resource providers by offsetting RPM payments with energy market revenues, which will make payments under the RPM system small or nonexistent. Of course there are many details to be worked out, and we confess that we have not thought through every issue that could arise in making sure that the programs can work in parallel without creating unnecessary market distortions.

In this regard, a vigorous and open stakeholder process to work through all of the details would be helpful. However, because PPL places such a high value on reliability, we are not willing to trust the future to RPM alone, nor should the Commission.

PPL believes RPM will fail, and there must be a market established in PJM to pick up the pieces if it does fail.

Thank you, and I look forward to your questions.

CHAIRMAN KELLIHER: Thank you.

Arnetta?

MS. McRAE: Well, Mr. Chairman, first thank you for allowing me to participate in this conference today and offer comments from Delaware. Recognizing that I was the last person on the panel, I frankly didn't see what comments I could provide that wouldn't be stated earlier somewhere along the proceedings. So if you don't mind, I assure you I'll not come back without written comments; but for this time, let me just offer my responses in addition to what Delaware has already filed. Because as you know, we have had prior filings in this proceeding.

I am not proposing at this time an alternative approach to RPM. What I'm suggesting is that RPM is a Band-

Aid, and what we really need is a holistic approach to what we're going to do with capacity, energy, transmission, demand response; and to look at and focus on one piece of the discussion I think does not get us where we need to be.

I'm specifically concerned about transmission, and that's even after hearing many of our speakers today comment on the balances of transmission as to why that should not be as great a factor. My concern is that if we don't look at transmission as an infrastructure component that facilitates markets, then we really run into the trouble of trying to make mix match and make fixes.

So from my vantage point, I would like to see us get the infrastructure straightened out, and I recognize we can't just leave capacity sitting, but recognize that that's something separate and apart.

As a member of the OPSI states, I think we should also play a role in trying to pave the way to get more infrastructure, because we all have our barriers, as Fred Butler spoke, New Jersey has its issues, and clearly Delaware has several; but as a group we need to work on that. PJM has done a commendable job in looking at that RTEP process and trying to open it up to longer-term. But I do want to caution that that's a plan, and a plan is not necessarily the structure on the ground, and there needs to be some steps and measures that are going to make that plan a reality.

I've seen the things in the queue over many years, and that doesn't necessarily follow that it will become real. But let me move on; I can add to that at some other time.

The short time window with RPM essentially talks about bid merit or peaking facilities, because baseload, there's nothing -- IGCC or otherwise, it's not going to be built in that time frame. So we're kind of locking ourselves into the kinds of generation responses that we're going to get.

A concern that I have about that is what we've just recently seen in the market as we've gone out to purchase for retail supply, is natural gas. And I think as it becomes a more competitive commodity globally, one being locked into that as a supply source, you know, is somewhat at risk.

So I certainly think that from our standpoint as a State, we'd like to certainly see more flexibility in what we might have available to tap into.

The administrative cost of RPM, which as stated here was modest, but when you couple that with the locational premiums -- and I think some of that was discussed by Mr. Weishaar of the Industrial Group, rarely do I find myself aligned with the arguments there, but I think several of the points that were made are also the thinking in Delaware, that we're going to pay a very substantial locational premium. And it invites the question as to whether Delaware would be better off just stepping off the system; I heard opt-out, and just doing our own planning for our state needs.

We know from experience that locational price premiums do not necessarily bring the response, and I've heard several explanations of why that may not have happened; let the price go higher and maybe something will occur, or there may be some ultimate barriers that can't be overcome. But the reality is that whether you call it a political fallout or affordability issue, at some juncture I think the States are going to look at how palatable are the kinds of prices we're going to have to face in order to get to where we need to.

In Delaware, after several years of locational marginal pricing, we sought and implemented an administrative solution. And that's very much anti-market, and I don't know if that's where you want to go, but I would submit to you, prices will reach a certain level and it will be the reaction of the affected states to turn back.

Thank you.

CHAIRMAN KELLIHER: Very well done. Good cleanup.

I wanted to start off, Mr. Tatum raised some issues where he argued that the core issue is transmission, and that we need to change our approach towards planning transmission, and I guess I'm not clear exactly what you're talking about.

Are you saying that PJM should plan not just for reliability projects but economic projects? That PJM somehow should be able to order a TO to build economic projects? I'm not sure exactly what you're talking about, because it does raise automatically, immediately you start thinking about cost allocation, how should cost allocation be decided if you have major backbone projects being built in PJM resulting from some effective regional planning process.

MR. TATUM: It's not an easy solution, and I think that's why we have been wrestling with it for a while. Within the PJM forum, PJM has taken strong steps to move forward in improving their transmission planning process, and Old Dominion strongly supports them in that regard.

I believe that PJM needs you'all's strong support as well, to whether possible opposition to weaken the planning process. There's a number of approaches that one can take from a technical perspective in planning the system, and these are engineering issues that you may wish to look at, and that required scenario planning. We've talked about market efficiency planning, and trying to get it done as up front and as quickly and put into place as possible. PJM would need the staff and the resources and the machines and the tools to be able to do that.

The other part of it, though, is much more complicated; and there's other forms that -- I hesitate to raise it unless we put a bunch of other numbers on this docket here. But you're actually right, we have to address cost allocation, we have to address long term rate design, and we have to have a system that not only takes care of interregional projects that might go from West Virginia to New Jersey, but also to take care of shorter, more local projects, which is really where we got into this process in the first place, with transmission constraint violations.

CHAIRMAN KELLIHER: Thank you.

Staff, do you have questions?

MR. MEAD: I guess Mr. Baker had something.

CHAIRMAN KELLIHER: Oh, yes, I'm sorry. Sorry, sir.

MR. BAKER: I would just like to somewhat echo Ed's comments. You know, a lot of discussion has been that the vertically integrated utilities don't want to build transmission because of the capital challenges between --

CHAIRMAN KELLIHER: Some of you do, apparently.

MR. BAKER: -- business units. Well --

(Laughter)

But universally when I've talked to transmission owners in PJM, the issues are twofold. One is recovery, and siting. And those are the factors that have limited people going forward and just ordering economic upgrades is not going to work unless we solve those two issues. So those have to be done.

And then I think you're not going to see a shortage of desire to build economic alternatives in the transmission field.

CHAIRMAN KELLIHER: Thank you.

Questions?

MR. O'NEIL: I guess we have two proponents of the energy-only markets, and at least Phil Hogan puts "energy-only" in quotes.

On the earlier panels, I think some of the panelists said they would love to see energy-only markets, but they don't think they're political reality. How do you deal with the political reality when those prices go to $9,000 and then there's lots of pressure on the Commission to do something about it?

MR. SHEFFIELD: Well, the idea of energy-only is not what we're advocating. What we're advocating is energy-only and mandated forward contracts, long term forward contracts, to hedge the risk associated with uncapped prices. So you have to have both components.

MR. O'NEIL: Would we, would the Commission mandate forward contracts?

MR. SHEFFIELD: I would think that the Commission mandates policy; PJM implements policy, so I think it would fall to PJM to mandate the long term forward contracts.

CHAIRMAN KELLIHER: It really would fall to the States, because we regulate sellers, sales, not wholesale buyers, and it would seem to be the province of the States, if they wanted to, they could certainly order load-serving utilities, state-regulated utilities to enter into long term purchase contracts and have some auction to make sure they're buying market prices.

But we want to be careful of our limits, and I really think that's beyond the pale for us to, unless there's some incredibly creative legal theory that I can't fathom, that we could mandate wholesale purchased by state-regulated utilities of certain terms.

MR. O'NEIL: That was the point I was getting to.

CHAIRMAN KELLIHER: No, I appreciate that.

Arnetta?

MS. McRAE: I would just comment on that point. I agree, it is the state obligation. But you'd be hard-pressed almost to get a long term contract, let's say in energy, when the market is as it is now and the prices are high, nobody wants to be stuck with you long term; they want to take advantage of the prices.

So there are some definite barriers to getting long term pricing when you have scarcity pricing or various things like that.

MR. O'NEIL: I can only remind you that when the California Commission, when the crisis happened, had essentially eliminated long term contracting, and it wasn't something we could do very much about.

And how do you -- we can do our part, but the long term contract part isn't our part. Then that leads to those high prices if the obligations aren't taken on.

MR. SHEFFIELD: As I said, it's important to have both components; and certainly the issue of how to go about getting the long term contracts in place to hedge that risk would have to be dealt with.

At the same time, those processes are happening right now, and most of the States of PJM through RFPs, through auctions. So a number of these long term forward contracts are already being put on.

What we are suggesting is simply a continuation of that process, a stepping-up of that process to the point where the majority of load is hedged against the risk of high prices.

Now certainly there are certain consumers, large industrials or commercial sophisticated users who can manage and in fact would perhaps benefit from exposure to the potentially high spot market prices by virtue of being able to demand control or take other types of steps to mitigate that.

But in general, to the extent that you were able to move forward with a structure that did encourage or even mandate the hedging of that risk, once that's done then you have a market structure in place that can function very well, because the long term forward contracts will define a long term price curve that investors can respond to; and at the same time the market, the spot market is free when you have scarcity conditions to rise to whatever level it needs to rise to, and strongly incentivize power suppliers to keep their generators on line and earn the margins that are available in that time period. And also strongly incentivize those who can do demand response.

MR. O'NEIL: But if your proposal were to work, then the only thing we would be out is maybe $2 million in investment in RPM, because it would be redundant.

MR. SHEFFIELD: For a short period of time.

I mean, yes, that would tend to lead to I think a level of investment that makes sense, according to market forces. To the extent that some adjustment might be decided on, so be it; but at least that would give the market a chance to produce whatever outcome it would produce.

CHAIRMAN KELLIHER: Mr. Hyzinski, did you have a response, a comment?

MR. HYZINSKI: I just want to add, you can attempt to, the States can attempt to oversee the polar process and attempt to facilitate long term contracting. But the important point is that with this type of a market, you have the incentive for long term contracting. It encourages long term contracting.

RPM does not do that; it does not encourage long term contracting. It's an auction, a centralized procurement that actually interferes with the short-term market.

Further, in order for you to see those $7,000 or $10,000 prices, you would have to presume that you would not have the development of demand response under such a market structure.

Currently in PJM, and as PJM I believe as they proposed the structure under the RPM, demand cannot set price. It does not set price now in PJM. And if you had the ability for demand to set price, the likelihood of seeing those high prices may diminish.

MR. O'NEIL: That sort of cuts both ways, if the demand is in the market getting very high, that demand could actually clear the market and there could be very high prices.

MR. HYZINSKI: Yes.

CHAIRMAN KELLIHER: And a question for Mr. Hyzinski.

In your statement you said that the Commission should require PJM to raise its thousand dollar price cap gradually up to the value of loss load. What would you estimate that to be now?

MR. HYZINSKI: Well, I don't have an estimate. Some of the papers that are out there estimate it to be somewhere between $2,000 and $10,000 a megawatt-hour, but it's one of these things where I don't think you'll ever find out what that number is, until you start to increase the cap and see how much demand response that you get. You can't ever find out how responsive it is until you provide the price for it to respond to.

CHAIRMAN KELLIHER: Let me ask a question for both you and Mr. Sheffield, who wants to make a comment in any event. But do you think, from your point of view if you think PJM markets are overly mitigated, is the hard price cap, a thousand dollar price cap, or is it the other mitigation that needs the price cap, the other. What's the quote 'mitigation' problem from your point of view in PJM?

Is it the hard cap? Your statement suggests that's the problem. Let's raise the hard cap. But is that the problem, or is the other forms of mitigation in PJM?

MR. SHEFFIELD: Well, philosophically, any caps or any mitigation on prices that prevent the market from functioning are undesirable. Now to the extent that high prices were caused by market power, well that says a whole different story and that would be appropriate.

But for there to be any distortions or limitations or caps on market prices to keep the from rising and operating as a true competitive and open market, we would be opposed to.

CHAIRMAN KELLIHER: Mr. Tatum? And then Mr. Moot.

Mr. Moot, you had a question? Mr. Tatum and then you.

Mr. Tatum.

MR. TATUM: Thank you, Commissioner. Just to weigh in on this, Old Dominion is extremely concerned, as we talk about a perception that the current market is over-mitigated, and we do not subscribe to that.

We are concerned about local market power, and we are very supportive of the local market power process that's been put forward today in PJM. We feel it's exceptionally important.

I do agree that when you have a market, you do not need the medication; but when you get into these smaller, local areas that's really where the crux of it is. So this is a dangerous slope to start going down. I'm sure there's going to be lots of other opportunities to talk about market power and market monitoring. Thank you.

CHAIRMAN KELLIHER: Thank you.

Mr. Moot?

MR. MOOT: I just wonder whether Mr. Ott could respond to the PPL proposal and in particular the question of what, if your RPM is approved, what's the remaining public policy rationale for the thousand dollar cap?

MR. OTT: Obviously if the RPM is proved and we have the situation where you have a feedback mechanism between the amount of compensation, if you will, under energy, which feeds back into the capacity pricing.

Essentially the rationale then for the overall price cap is essentially to make sure that the market itself has enough capacity to develop a demand response to, I'll say compete, if you will, on the overall price cap.

Again, the concept of putting RPM into deal with the problems that we've discussed today, and over time evolving into an energy-only; some folks have said it was it was an exit ramp, and some of these other, is not necessarily a bad idea. But again I think there will be many stakeholders in PJM who will urge caution in doing that.

I think fundamentally, dealing with an energy-only market concept has a lot of additional complexities that we need to work on, including regulatory intervention, things like that. And obviously mandated forward contracting, just doesn't seem to sync up, at least on a market-wide basis.

So certainly putting in RPM and then over time allowing that RPM to show the capacity prices where you need them, I think that's essentially the philosophy we have. And we wouldn't necessarily be opposed to looking at revisiting the price cap with RPM in there.

MR. O'NEIL: Tom, you said that in PJM, demand can't set the price. Is that true?

MR. OTT: No, that's not true.

You mean in PJM market? Of course we can set the price.

MR. O'NEIL: How does it do that?

MR. OTT: You mean in RPM, or do you mean in PJM energy market? I'm sorry.

MR. HYZINSKI: I don't believe it can today. You can't set it in a day ahead or real-time markets. So the only place it might be able to set it is in RPM, if it would set an RPM auction price, an RPM auction somehow. But I don't believe it can.

MR. OTT: I think in the price-sensitive demand bids that are put in the day ahead market, can certainly set the price. If you're talking about the real-time demand response, unless it has appropriate metering in place, practically speaking do we have any real-time demand response to respond to the price to be able to see the price, or set the price? Probably practically thinking, we don't. I don't think there's a market rule prohibiting it, especially given the new demand response filings that are out there.

So I think the day ahead certainly can, and again the RPM, it can affect price on a forward-looking basis.

MR. HYZINSKI: But you would agree that you can't set the price above a thousand, so that if demand in fact valued -- its value of loss load was greater than a thousand, it is impossible to do that?

MR. OTT: I would agree with that.

CHAIRMAN KELLIHER: Mr. Tatum?

MR. TATUM: Thank you.

As we've gone through this day, we've spent a lot of time talking about the critical area where we currently find ourselves, and the need to move forward, and quickly, to correct a current problem. And I think these two proposals are fascinating. I do not know how long it might take us to implement them in conjunction with RPM.

And to that end, I think they would be good discussions to have and I think we should roll back to Wilmington and take a look at it.

In the meantime, I would like to suggest, given the discussions we've had with regard to transmission and the dire straits we seem to be in, that an incremental approach such as proposed by the ITCC could indeed take us down the road to capacity construct modification without unduly burdening the load and the people who are going to be paying for it.

And again, we've offered up a local element that we would like to flush out and make work with the stakeholders. We've talked about extending the commitment from 1 to 365 days, and having more certainty in the future as to what the actual installed reserve margin construct would be.

Again, the current market right now, load which has the reliability obligation, already has the option to achieve what benefits there are from RPM. That's the price certainty. But it's choice; we have the choice to do that, and that's what markets are all about. So we feel application of the demand curve would wrongly eliminate an important element of that.

I just wanted to come back to this.

CHAIRMAN KELLIHER: Thank you.

Arnetta.

MS. McRAE: One thing I did forget to mention is if we do decide to proceed down the path of RPM, that the discussion we had around demand curve earlier is an important one, and I do think that there should be some examination of some of the underlying assumptions, I think you jokingly stated, which assumption, which set do you want to choose?

But I think there are some very important considerations as to what will come out by looking at the various components of how you get to that curve.

CHAIRMAN KELLIHER: Thank you.

Mr. Baker?

MR. BAKER: This is my -- I'm cooking spaghetti tonight.

(Laughter)

And if this were to go back to PJM, the thinking of the conversation that Chairman Schriber had and Mr. Brown from GDS, one of the things that we say over and over again and seem to fall on deaf ears is that our customers do not receive market prices. Our generation, except for a small surplus, does not receive market prices.

We're set at cost of service regulation across our area, and so things that have large administrative costs with no price signals having movement either way about the activities we do, just add to the cost of our customers.

And that's my spaghetti.

CHAIRMAN KELLIHER: Thank you.

Any other questions? Tatyana?

MS. KRAMSKAYA: I had question for Mr. Ott.

In the transmittal letter, PJM stated that RPM will eventually transition into an energy-only market. Looking at RPM, the construct as we have it today, which of the elements do you think would make it the most difficult or the easiest to get there, to an energy-only market?

MR. OTT: Again, I think the elements of RPM, which are the locational component, the variable resource requirement with all the feedback mechanisms we talked about that are included and in place, essentially what again as the results have shown, effectively the capacity price drops to very low levels. Effectively that area, essentially, is seeing an energy-only type construct. Although there is a back-stop that says, indeed, if there isn't enough installed reserve in that area, the price would go back up.

So effectively, the evolution in the various areas, essentially the price would atrophy or tend to remain at low levels. And again the point of the RPM discussion that we're having is nobody's debating certain retirements in certain areas where we have excess capacity and nobody questions that; it's a market mechanism that works fine. It's where you have these other areas we have shortage that you need the price to be proper.

So the context of evolving to energy-only was in that. But I think it's also critical, though, that the forward pricing -- again, we've had these debates within a stakeholder process, with all due respect to Mr. Tatum's ITCC proposal. The fact is if you only look one year out, you're not essentially capturing the actual requirement for capacity. You need that to be on a long term basis; you need to look at the participation of new entry, because you have to get out far enough to allow that meaningful participation to get there.

CHAIRMAN KELLIHER: Tatyana? That was your question? Okay.

David.

MR. MEAD: One more question.

Mr. Baker, with regard to your proposal for opt-out, are you proposing to allow LLCs on a year by year basis to decide whether to opt out or not? Or would there be some sort of commitment for a number of years to opt out?

MR. BAKER: Oh, I think it has to be a long term, and you have to come forward with a long term plan. We provide many of our states IRPs which show what we're going to do over the next 8 to 12 years, depending on which state you're in, and I think you'd have to show that kind of a plan. I don't think you can just bounce in and out as you see optionality benefits.

MR. MEAD: One or two more questions for Mr. Hyzinski.

Mr. Sheffield talked about how there was a role for limiting bids in prices where there's market power, but not otherwise.

First of all, do you agree with that principle?

MR. HYZINSKI: I agree with that. I mean the idea is when we've run out of megawatts, you have to have scarcity pricing. If you don't have scarcity, there's an obvious need for market power mitigation; I don't dispute that.

MR. MEAD: For the two of you, do you agree generally with PJM's current triggers for determining that there's local market power in the energy market and that when those triggers are triggered, that some sort of bid mitigation is appropriate?

MR. SHEFFIELD: Yes.

MR. HYZINSKI: Yes. And there's been a recent scarcity settlement that has improved that, yes.

MR. MEAD: Okay. So primarily I gather your proposal is with regard to the thousand dollar bid cap, and that it would be increased; but that when the market power triggers are triggered, that the local market power mitigation would still be appropriate?

MR. HYZINSKI: Yes.

MR. SHEFFIELD: Absolutely.

MR. MEAD: Thank you.

CHAIRMAN KELLIHER: Okay. We have a few minutes here.

If there's anyone in the audience who would like to ask a question of this panel.

Any takers? Just raise your hand; otherwise I will go -- Yes? Yes.

AUDIENCE: Thank you, Mr. Chairman. My name is John Levin, attorney with the Pennsylvania Commission.

We've heard a lot of figures today, and some of which appear to be based on guesstimates; and one of the figures -- or a couple of versions, we might want to talk about a little bit is with regard to an all-energy market. We've heard $9,000 a megawatt and $12,000.

I can't remember who was associated with which figure. Obviously it's not based upon actual market operations; it's based upon some suppositions, some assumptions.

Do those figures include what would happen if we had fully integrated demand response and some sort of a long term forward contracting obligation? Or are they based upon the market as it stands now.

MR. O'NEIL: I can answer. If the demand

response is fully integrated, you don't need any of that. Demand will set the price when there's scarcity.

MR. LEVIN: I understand that, but there's been sort of figures tossed out, well, what will happen if the price goes up to $9,000 or $12,000, and what will the reaction be?

Are those $9,000 and $12,000 figures, are they realistic? Or are we talking about something we don't know enough about yet.

MR. O'NEIL: I thought your assumption was there was full demand response.

MR. LEVIN: Right.

MR. O'NEIL: And then if that was the case, those numbers would come from the demand responders, the people who are willing to pay that much; and I assume that if they said they were willing to pay that much, they meant it.

MR. LEVIN: But would the numbers be as scary --

MR. O'NEIL: Don't know.

MR. LEVIN: -- as stated.

MR. STODDARD: If I could take a stab at answering that. im Robert Stoddard with CRA, representing Mirant, NRG, and Williams.

I think the numbers we heard on the record earlier today were saying if the marginal unit on the system is a peaker, if that is what we're going to count on to provide our reserves, what does it need in the market? And the inframarginal rents it needs would be equivalent to the cost of new entry, which we've calculated at about $72 a kilowatt-year in PJM.

If under reasonable assumptions it's only going to be running seven to ten hours a year, that gives you the prices you've heard.

Now the way out of that box, as you posit, is that it's not the peaker that's at the margin, but that it's demand response at the margin.

Now the question is, can we get the infrastructure, can we get the billing system, can we get the state tariffs in place to have price responsive demand, and will the operations center at PJM have sufficient confidence that the price responsive demand will be there when prices are high, that they can skate as thinly as would be implied under that structure.

And I would actually like to pose that as a question to Mr. Ott; there's two kinds of a demand response. There's active load response and there is just price response; price is high, people buy less.

Can you rely, as an operator in running your daily system, can you rely on that latter sort of demand response, incredibly keep to your NERC standards?

MR. OTT: I can only rely on resources that I can dispatch and get a response from. If you give me a big red button to hit in the control room, it sheds the load; then yes, I can depend on that.

I think the infrastructure that is necessary to get there, and the willingness of that load to get off, I think again is in question. And again, the concept here, though, is that again until the debate really has been if prices go that high are we going to get real demand response or are we going to get phone calls to you all saying "the prices are too high, let's do something, or probably worse, to the governors or whoever." And I think that's really the debate about the energy-only.

CHAIRMAN KELLIHER: Mr. Tatum?

MR. TATUM: John, in answer to your question, the numbers would be as scary.

CHAIRMAN KELLIHER: Mr. Hyzinski?

MR. HYZINSKI: I think there are two things that were left out. The two things that were left out is, if you get enough demand response, you wouldn't have built that peaker in the first place. That's one thing.

The other thing is, I think when we're presuming an energy-only market as it's defined in those papers that were submitted, we're talking about a market where we co-optimize the reserves with the energy, and we have a cushion of 3 to 7 percent reserves, or whatever the NERC requirement is.

So you would not violate your NERC requirement.

CHAIRMAN KELLIHER: Are there any other questions from the audience? And I want to be clear; questions, not statements in the form of questions. But any questions from the audience?

(Laughter)

AUDIENCE; David Popper for the Virginia -- and this is a question for Mr. Ott. If I can put it in the form of, 'is it true that' and if so, how does this follow?

CHAIRMAN KELLIHER: A leading question is all right. It's still a question.

MR. POPPER: Isn't it true that the locational price at or revenues flow back to the LSEs in the zone, all LSEs, such that if you're a transmission owner with a lot of generation in zone, you benefit from capacity congestion that raises the local price of capacity in your LDA.

And if that's true and the TO has an important bottom-up role in transmission planning, isn't this an opportunity to give people a stake in congestion that will defeat transmission planning?

MR. OTT: I don't know if I quite understood the question.

Is your questioning about locational pricing or locational capacity pricing?

MR. POPPER: Locational capacity, LDA, the revenues from this.

MR. OTT: Okay. Essentially the revenues from the demand, the load customers paying elevated prices in the constrained area. Some of that revenue goes to pay the generation that's in the constrained area, their capacity price.

The other part of the revenue goes to pay a fund, if you will, the capacity transfer rights. Essentially the rights, the dollar value, if you will, of the transmission import capability. That goes to the load serving entities, not to the transmission owners.

MR. POPPER: Aren't those sometimes the same entities?

MR. OTT: Excuse me?

MR. POPPER: Aren't those sometimes the same entities, under the same corporate umbrella?

MR. OTT: I guess it depends on their structure. I think in some of the areas we're discussing here, a lot of those load serving entities are indeed somebody else, because it's the New Jerseys and some of these other places where I believe those are quite unbundled.

CHAIRMAN KELLIHER: Any other questions from the audience?

Seeing none, Staff? Last opportunity.

No? Okay, I'll make some very brief closing remarks.

CHAIRMAN KELLIHER: First of all, I want to thank this panel and the previous panelists for helping us on this. This is a difficult issue and it's important, but you've been here on a Friday before the Super Bowl, helping us deal with it, and I'm grateful for that.

I think the conference has been very interesting. I've really liked the exchange of views and I think the panel were well organized to have diversity of views within them; that helps us.

The RPM proposal is an important proposal, and I want to commend PJM for the goal of their proposal. They are trying to prevent the PJM region from going down the path of California and New England. And my understanding is that their purpose is to address these issues before they become more painful and more costly. And their goal at least is to assure reliability and to assure just and reasonable rates.

So I think they're pursing the right objective. There was a broad consensus here today that, and I think reflected on this panel, too, that there is a problem under the status quo; that the status quo can't be relied on to assure reliability and to assure just and reasonable rates.

We've seen a variety of alternatives and I think we've had a good discussion of both RPM, the aspects of RPM, and those alternatives, particularly from this panel. And that's helped us.

I think there's been a recognition that some of the transmission planning issues need to be addressed in PJM. That was something that came up from a lot of the panelists, and that's something we'll have to talk about a little bit further.

At this point I'm going to have to consult with my colleagues, and we'll decide collectively what our next step should be; and I want to make sure that all parties to this proceeding know that they can file written comments on the technical conference by the close of business on Friday -- I don't know if it's Friday, but on February 23rd, 2006. So the record will be open until February 23, 2006.

And again, I just want to thank everyone for helping us with this proceeding, and have a good weekend. Thank you very much.

(Whereupon, at 4:36 p.m., the conference concluded.)