BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Numbers

PJM INTERCONNECTION, L.L.C. : ER05-1410-000

: EL05-148-000

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Commission Meeting Room

Federal Energy Regulatory Commission

888 First Street, NE

Washington, DC

Wednesday, June 7, 2006

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

BEFORE: ANNA COCHRANE

P R O C E E D I N G S

(9:05 a.m.)

MS. COCHRANE: Could we get started, please?

Good morning. I am Anna Cochrane, the Director of the Division of Tariffs and Market Development East in the Office of Energy Markets and Reliability. This is a Staff Technical Conference in the matter of PJM Interconnection LLC's proposed reliability pricing model, or RPM, filed August 31st, 2005, in Docket Numbers EL05-148 and ER05-1410.

On April 20, 2006 the Commission issued its initial order in this proceeding. In that order the Commission found that PJM's existing capacity construct is unjust and unreasonable, made rulings and providing guidance as to various issues raised with respect to establishing the just and reasonable replacement for the existing construct, and established further proceedings, including a paper hearing and this Staff Technical Conference to resolve remaining issues.

The Commission issued a notice on May 1st establishing the dates for this conference. This conference is intended to be an informal working session focused solely on determining the appropriate parameters for satisfying capacity obligations.

The April 20th order found it is appropriate to allow a dual method of satisfying capacity obligations from which states and utilities can choose. One method would be the use of the capacity auction approach proposed by PJM with the price set at the intersection of a downward sloping demand curve and supply bids made by capacity resources.

The Commission found that such a demand curve is one just and reasonable method of establishing capacity resource prices but determined that the parameters and slope of the curve would be established with the benefit of additional information that will come from today's technical conference.

The Commission found that the second method would be to require each LSE to be responsible through self-supply or contracts for meetings its locational reliability targets for the procurement period. This option would result in a capacity requirement for LSEs that is fixed. Certain details of this approach will be determined with the benefit of additional information that will come from discussions tomorrow.

Since this is intended to be an informal working session panelists will please dispense with opening remarks. You guys have already provided position papers in advance of the meeting, so we will just kick off with questions from the Staff.

If time permits we will take questions or comments from the floor on each topic.

As you see, there is a microphone set up on the side of the room. And once we open up each topic to questions from the floor we'd like people who would like to ask questions or make comments to line up at that mike. If you're speaking from the floor, please begin by identifying yourself and the party you represent, and please limit your comments to no more than two minutes.

With me from Staff are John McPherson, Tatiana Kramskaya, Dan Nowak and Debbie Ott from OEMR East, and Dave Mead and Dick O'Neill from the Policy Division, and Mike Goldberg, Chris Wilson, Sue Ehrlich and Kathy Waldbauer from the Office of General Counsel.

Is that everybody? Did I get everybody?

(No response.)

MS. COCHRANE: Also I'd like to recognize Sarah McKinley, who has been instrumental in organizing this event.

Before we begin I'd like to set out a few ground rules. First, all speakers should limit their comments to matters in the RPM proceeding. Please do not address other matters that are pending before the Commission in other dockets.

Second, for those parties who have sought rehearing of some of the Commission's rulings in the April

20th order, please do not reargue your position as to those rulings.

This conference is intended to address solely the technical aspects of developing the variable resource requirement curve and a long term fixed resource adequacy requirement as set forth in the April 29th order. We recognize that some parties have sought rehearing on these issues. But for purposes of this conference please assume that those elements will remain part of RPM.

Some housekeeping matters. Let's plan to have a 15 minute break at 11:00; break for lunch between 12:30 and 1:30, and have another 15 minute break at 2:45.

If you plan to pass out any materials during this conference please make sure that every document you distribute today gets entered into the record for this case. You can do so by sending an electronic version to Sarah.McKinley@FERC.gov, or else please make sure that at least one hard copy of your document gets to a FERC Staff member.

Whether you use the electronic or hand-delivery method, please make sure that the name of the party submitting the item and the fact that this needs to go into the record for this docket are clearly marked on the document. If you can, please make sure you provide a copy for each of the Staff and the Court Reporter. And extra copies may be placed in the back of the room.

And, as mentioned in our notices, all parties are welcome to submit published conference comments if they wish to do so by June 22nd.

Our panelists today are Andy Ott, Dr. Benjamin Hobbs and Raymond Pasteris on behalf of PJM. Kichan Choueiki, senior energy specialist, Public Utilities Commission of Ohio, Esra Hausman and Jonathan Wallach on behalf of the Coalition of Consumers for Reliability, or CCR, Seth Parker on behalf of Midwest Generation, Edison, Mission Energy Consolidated, Edison Energy, Connective Energy Supply, and Constellation Energy Commodities Group, Matt Picardi on behalf of Coral Power, and Robert Stoddard on behalf of the Mirant parties.

And hopefully that's everybody who is sitting here today.

MR. STODDARD: Anna.

MS. COCHRANE: Yes.

MR. STODDARD: I'm also here today on behalf of Dayton Power and Light and the Williams Company.

MS. COCHRANE: Okay.

MR. WALLACH: And, Anna, technically I'm here on behalf of the Maryland Office of People's Council, a member of CCR.

MS. COCHRANE: Okay.

Any other corrections?

(No response.)

MS. COCHRANE: All right.

At this time, then, I'll turn the mikes over to the Staff for questions.

MR. MEAD: Just to begin the panel, I would like to ask a general question about what is the general objective that we should be trying to achieve when we agree on a demand curve, its height, slope and so forth. What should be the target reliability objective? Should it be a curve that gets us, you know, the standard one day in ten-year reliability standard that is avoiding firm outage of no more than one day in ten years? Should it be making sure that the capacity in PJM never falls below IRM? Or should it be something else? Let me throw that out to the panel.

MR. ANDREW OTT: Sure.

This is Andy Ott from PJM.

When we were assessing what we were looking for in a curve the IRM actually is a metric that we do analysis on to provide us with the equivalent level of reliability of one day in ten years. That's essentially the metric.

And when we were looking at the performance of various curves there were essentially two categories of performance we were looking for. The first was to have, you know, very high probability or very high occurrence throughout the analysis of the curves where we could be reasonably sure that the IRM during, you know -- not absolutely sure, but pretty close to sure that the IRM would always be attainable. In other words, we would always have sufficient resources to cover the IRM requirements. So it wasn't an absolute where, you know, it has to be 100 percent of the time necessarily, but the probability has to be fairly high.

And the second was the metric of cost. In other words, there's a balancing act between supreme reliability and cost. And so the reason the reliability of the IRM wasn't set at 100 percent, you know -- meaning every possible occurrence -- was because you have to balance out what the cost would be.

So as we were evaluating these it was really, you know, looking at the performance of reliability as high as possible without going too far on cost. So that was really the metric that we thought was the most, because none of this is an absolute.

MR. MEAD: Under the PJM proposed curve where the price -- the net cost of new entry is pegged at a price of one percent above IRM -- and we'll get into this more this afternoon --

MR. ANDREW OTT: Right.

MR. MEAD: -- the forecast is that a small percentage of time capacity would actually fall below IRM but most of the time capacity would be above IRM. And presumably, you know, the percentage -- during the times when you fall below IRM your risk of an outage is more than .1 day per year, but that's balanced against a probability of outage of less than .1 in the years when you're above IRM.

Is there any sort of calculus there?

MR. ANDREW OTT: Well, yeah. Again it was very similar to when we set operating reserve targets in the operating day. We have certain standards that say we will have, you know, a certain amount of regulation, for instance, on the system and -- you know, each hour of the day. So we set a target and we try to meet that target.

Every once in a while an event that would require you to go -- that results in your being, you know, a little bit short in regulation -- and there's procedures to deal with that emergency condition. And that way you balance the -- you know, obviously I could just schedule two times the amount of regulation I think I would need and I would never have that case, or I could schedule it, you know, more efficiently, if you will, and then have procedures to deal with the relatively improbable event that I would be short.

Similar in capacity. You know, obviously we could just create a curve that has, you know, buys so much capacity that you would never be short. But then, of course, that would cost a lot more.

So the point is is if you design a curve that gets you there 98 percent of the time and you may have two percent of the hours, you know, so over 100 years it might be twice, then there's a way you could create certain operating procedures. Because essentially the 15 percent is an installed reserve margin. What that means is you may or may not -- if you go in with less than 15 percent you may not on a given day have enough operating, you know, units capable of operating to meet the peak load. But then you have certain operating parameters that would get you through that very thin period.

Again, the alternative would be to spend a lot more to get that extra two percent. And we thought a balancing act would be between the two.

MR. MEAD: Just one thing before we pick up on that. I mean it sounds like you're -- if you could ignore costs, your objective would be making sure that capacity never fell below IRM.

MR. ANDREW OTT: Absolutely.

MR. MEAD: And that would result in -- I mean if you believe the philosophy underlying the one day in ten years in IRM, that you would have more reliability than one day in ten years.

MR. ANDREW OTT: Because you have --

MR. MEAD: Because my understanding is that if capacity is at IRM all the time then you have one day in ten year reliability.

MR. ANDREW OTT: Correct.

MR. MEAD: And if you have on average -- if you never go below that on average you're above it then you have more than one day in ten year reliability.

MR. ANDREW OTT: Correct.

MR. MEAD: Okay.

MR. ANDREW OTT: That would be correct.

MR. HOBBS: Can I just clarify -- That was just the point I was going to make.

MR. O'NEILL: Can I just clear up one issue about the one day in ten years?

Do you have -- Is the criteria one event in ten years or one megawatt day over a ten year period?

MR. ANDREW OTT: I believe it's an event.

MR. O'NEILL: That also leads to some problems because a small event is counted the same as a large event, right?

MR. ANDREW OTT: Right.

MR. MEAD: Do other panelists agree with this objective?

MR. CHOUEIKI: Kichan Choueiki with the Ohio

Commission.

Let me first say that I am representing the Ohio Staff, not the Commission, because my remarks were not approved by the Commission. They were approved by the Ohio Staff.

I agree that the first objective should be the reliability, one in ten years. That seems to come up to about 14.7, 14.8 percent, so 15 percent IRM is a very good reliability objective. We've used that historically in Ohio and I think most of the country.

I agree, too, that the second objective is least cost to consumers, so that -- I think Andy mentioned that.

I think a third objective, since we are interested in encouraging investments in the grid, should be also whether the demand curve encourages investments, and not only in generation but also in transmission or demand response solutions.

So it's a multi-objective, basically, function which we have to maintain reliability of 15 percent, one in ten years, we have to provide least cost, the demand curve, such that it is at least -- you know, try to experiment with a bunch of demand curves to see what would give us the least cost to consumers. And thirdly, encourage investments. And not only encourage investments in generation but also in transmission. And the demand response solutions.

MR. O'NEILL: Can I ask you a question?

Let's suppose we had, let's say, a world where all the demand was expressing their desire to consume; that is to say that they would tell you which price at which they didn't want to consume. What would we have to change or what would the demand curve -- would we need a demand curve?

MR. CHOUEIKI: If you're asking me, probably not.

MR. O'NEILL: Anybody.

MR. CHOUEIKI: My opinion would be not because then everyone is responding to the real time pricing basically, right?

MR. O'NEILL: And so --

MR. CHOUEIKI: And so it's like gasoline.

MR. O'NEILL: And so this demand curve is a surrogate for the value of load, the value of a megawatt to consumers?

MR. CHOUEIKI: No. You see it's -- again, we have reliability here. It's not like, you know, buying a product, you know, where there is competition.

MR. O'NEILL: Well, put whatever reliability you want into the market and suppose that all of the people who were buying power out of this market were expressing their willingness to pay. What would it look like then?

MR. CHOUEIKI: How would the demand curve look like?

MR. O'NEILL: What would -- yeah, would you need a demand curve for reserves? You may need reserves --

MR. CHOUEIKI: Yes.

MR. O'NEILL: But would you need a demand curve for reserves?

MR. CHOUEIKI: I'm not quite sure.

MR. PARKER: I'd like to weigh in on both the questions.

The second question, what the demand curve would look like, I know there have been studies trying to estimate based on the value of load to individual customers, be they residential, commercial, industrial. But it's a very difficult effort. On the other hand --

MR. O'NEILL: By the way, that wasn't my question. My question is suppose the people who are buying power are expressing their value so you don't have to estimate it. Okay?

MR. PARKER: I think the trouble is that people might say one thing but behave differently.

MR. O'NEILL: No, no. I'm -- They're bidding into the market. They have to take the consequence of what they bid.

MR. PARKER: Or an industrial customer who can do that calculus, be they an aluminum producer in the northwest or in the California energy crisis or others, they can, you know, say yes, we'll shut down for half a day or a day because electricity prices are too high and we can offset out lost revenues.

But for residential customers I think it's a very difficult exercise.

MR. O'NEILL: But I'm not sure you heard what I said. I said suppose we have it. I'm not saying how --

MR. PARKER: Suppose we have it.

MR. O'NEILL: -- difficult it is to estimate. But suppose you and I have the ability to express our desire to consume electricity and the FERC could do the same thing in the PJM market. What would the -- what -- Would we need a demand curve or would we simply need for a certain amount of reserves to be specified?

MR. PARKER: I'll tell you what. I'll try my best to answer that. And if I can't I'll let someone else. But I do want to get back to David's point.

I think you would end up with a curve that looked something like the demand curve based on cost of new entry. You would end up with a curve that had that general shape.

But, David, back to your question, the way I was looking at it, I was sensing a concern that by setting a demand curve that allowed prices if supply were less than IRM, I seem to be hearing a concern that, you know, there's some tacit not approval, but allowance for that situation to occur.

I think the way the demand curve really has to be interpreted as being able to set price signals. So, yes, that demand curve extends to IRM levels less than where it has traditionally set at 15 percent or other numbers. But that's how you get price signals to incentivize generators. And if generators have assurance, long-term assurance that prices will be, say, at a high level some years in advance, you know, that's the market mechanism to incentivize generators to locate in the right areas.

MR. MEAD: Why don't we just go down the line.

Mr. Picardi.

MR. PICARDI: Yes. I think you've raised an interesting question kind of from the point of view that -- and I'm not sure which -- the cart before the horse because I can agree 99 percent with what Andy said about reliability and price. But the question is then you go, well, how are you going to get there assuming we all agree -- and I guess I'm bypassing Richard's question -- assuming we all agree that we're trying to get to IRM.

What's important to us -- and I think the problem is that at least from our perspective we agree in principle that the curve that's been proposed doesn't focus enough on -- and needs more analysis on investor risk when you get at IRM-plus. Because the Commission's goal was to make sure not only were we sending adequate price signals to encourage new generation where it exists, but to make sure we're maintaining the generation where it needs to be maintained. And if we don't study the surplus side of the curve well enough and consider the impact of that on the market and investment decisions to maintain units, I think that we'll have a problem.

So my concern about going down the road of looking strictly at that one point right at IRM is we'll get lost in that discussion and not think about, well, okay, how are we going to actually make sure we maintain that and don't slip off it because it's a lumpy process and it's not going to happen, you know, one year to the next that it will be there and it won't be there.

MR. MEAD: Just before we go down the line, we're here to get information. And personally I haven't drawn a conclusion about what the proper objective is. But I have heard at least three objectives.

One is what I thought was the basic objective, which was get enough capacity so that on average or over time we will get a one day in ten year level of reliability. You know, another one would be, well, it's too hard to figure out that so let's just make sure that with the demand curve we either don't fall below IRM, which will assure that we'll never get worse than one day in ten reliability, or, if we have to go below, don't do it very much. Or a third possibility is why don't we try to figure out what the level of reliability of customers actually is and, you know, develop a demand curve that way.

And it seems to me that all those objectives are in play. And that's, you know, one of the reasons we'd like to hear all of your views today.

Why don't we go to Mr. Stoddard.

MR. STODDARD: Let me try to cut through the Gordian knot of that last very good issue you bring up, Dick.

The consumer preference is embodied not in the demand curve but in the IRM. There has been an administrative decision that 15 percent or one in ten is the right standard. That administrative preference for reliability becomes embodied in that number.

Now if we're willing to abandon that number we're willing to allow the margins to slip to wherever the natural economic forces would let them go, then we can probably do without capacity markets. But until we get there I don't see that we're willing to abandon IRM yet.

MR. O'NEILL: No, no. I guess maybe that wasn't my point.

We maintain the one in ten year reliability standard. Okay. That's still on the table. The issue is can you get there by having a demand curve or allowing, let's say, industrial and commercial customers -- so we don't have to debate whether residential customers are intelligent enough to bid -- to leave the system voluntarily and therefore satisfy the reliability by leaving the system voluntarily. And if that's the case would we -- would it be sufficient if they could express their willingness to pay -- do we need a demand curve for reserves or do we just need a specified reserve number?

MR. HOUSMAN: I think the answer -- excuse me, I apologize for being late this morning -- I believe the answer is that we wouldn't need a capacity market at all if consumers could in fact fully participate in the electricity market and express their willingness to pay.

And the only reason that we're here talking about a capacity market and capacity market structure is because of the market failure that consumers have not been able to express that willingness. And so we need to have an excess of capacity to some degree. And I guess we're here to discuss to what degree we need an excess of capacity over and above what consumers would actually be willing to pay for.

MR. STODDARD: Well, that's probably the major contributing factor. There are other reasons why the energy market is not throwing off as much margin as the installed capacity needs. Probably the largest one is the fact that we have an installed reserve margin which is high that doesn't allow it. There's also price caps. There's also a number of ways in which the exact LMP formation is not performing with the theoretical locational pricing, all of which tend to suppress prices.

But given that, I take the larger point that what we are doing is we've made a decision to have an installed reserve margin. It's not necessarily market tested but it is the received wisdom of how the system runs: What is the level of reliability that we have traditionally maintained. And if we're going to hit that there is clearly, as has been demonstrated in every pool, a shortfall of net revenues to generators. And that missing money has to come back through some mechanism.

Then we're left not with a decision of, well, is the demand curve intended to hit a particular consumer willingness to pay -- because we've already seen that the IRM may not conform with that; it's an engineering standard more than anything else -- we now have the different objective, which is if we made a decision collectively to hit a reserve target -- well, first how do we make sure that anyone who is willing to opt out has that ability -- and I think PJM has tried to make demand response a very viable part of this market; that's how consumers express their preference to opt out -- and, secondly, can we do the job at hand, which is to hit the IRM, often enough at an appropriate cost to consumers.

One of the key points -- and I want to pick this up from Matt's comment -- is that we discussed time and again in the litigation around New England, the key thing that a demand curve can do is to reduce the volatility of the revenue streams to developers and new resources, and consequently reduce the financing cost of those resources. Ultimately that saves consumers money.

That is perhaps the single most important feature of a demand curve, that it takes what we know is a need for a long run revenue stream and without completely muting the price signal -- high when there's a shortage; low when there is a surplus -- that we reduce the volatility, provide more stability of the market revenues to the overall market design and achieve, consequently, lower total cost to consumers.

MS. COCHRANE: Jonathan has been waiting to say something.

MR. WALLACH: I have a number of things to respond to.

First of all, I just wanted to hopefully respond to the question you were asking, Dick, and say that if consumers -- if load has the ability to fully respond and

PJM has the ability to interrupt that individual customer, then, A, we probably don't need a capacity market, notwithstanding Bob's comments, but, B, I have to take issue with what Seth said, which is that the demand curve would look the way it is proposed under RPM that it would be pegged to the cost of new entry because what would happen is if you've got consumers who are able to respond and reveal their willingness to pay then what you've got is a market-based demand curve which doesn't look like a new entry based curve, it looks like a curve based on the value of loss of load, for better or worse.

MR. O'NEILL: Yeah. And that's the way I read the questions today. That's the question that's on the table in the first discussion. What should -- where -- fundamentally how should this curve be estimated or --

MR. WALLACH: And the fact is the reason we're here today is because consumers don't have that ability and PJM doesn't have that ability to kick someone off the system if they're free riding. And so the question then becomes is what is -- what's the appropriate surrogate for, you know, that market based curve.

MR. O'NEILL: One of the issues that comes up is if that curve is estimated too far to the left then it discourages demand from bidding because they become free riders in the system.

MR. ANDREW OTT: I wanted to pick up on that because I think what the demand curve is doing is essentially saying here is the reference for us to provide -- and again I guess I would argue that we're really not looking -- when you're talking about averages with IRM, you know, obviously if I had an average IRM of 15 percent over a two-year period I could have one year where it's five percent and one year where I have something much more.

MR. MEAD: I would disagree.

MR. ANDREW OTT: And obviously that would be unacceptable. Right, because --

MR. MEAD: As I understand the studies, subtracting one percent capacity from IRM will increase the risk of an outage more than what you save by adding an additional one percent IRM above that. And so if you have a demand curve in order to preserve one day in ten years you need an average level of capacity that's more than IRM --

MR. ANDREW OTT: Or below.

MR. MEAD: Right. You know, occasionally you can fall below. But on average you have to be above.

MR. HOUSMAN: Right.

MR. ANDREW OTT: But again, I just wanted to get back to, you know, the cost of failure is so immense here that obviously you wouldn't -- those averages could be misleading at least from a reliability perspective. For instance, with regulation I couldn't say my average regulation over a two-hour period is 300; one was zero, one was 600. You know, I would be thrown out of various reliability councils and other things if we ran the system like that.

So it's just not something that -- so really the IRM is a number you really don't want to go below very often.

But let's go back. The demand curve itself is saying, okay, here is the price of, you know 100 percent participation. Here's sort of the reference, if you will. Under the RPM and in the energy market, you know, we have the ability today for demand to exercise this alternative that says I'm coming out. And, you know, we have seen it at times where demand has failed to do that and then, you know, as prices go up we've actually seen lately much more interest in demand response.

So I think the real goal here of what I'll call backstop mechanism, which is to get the price right -- just say, okay, here, if you really wanted to be on the system for every amount of megawatt you wanted to consume, here is what it would cost. The demand curve is providing that reference to say here is that. But also then you have this ability, low barrier entry ability for demand response to come in and say, you know, I'd rather not be there and here's the price at which I'll stay. And that's what the RPM does. And we also have, of course, the equivalent in the energy market and then for the short term demand we have the ILR, which is another way to get out.

So I think the demand curve itself I don't think is the value of lost load as much as it is, okay, here's what the price will be if you want to stay, and then you decide, you know, whether you want to stay or not. You should have that what I'll say low-barrier entry exit.

Now I agree with Jonathan, though: to exercise that you need to put in the requirements to have metered interchange, et cetera.

MR. WALLACH: Dave, I just wanted to insert a word of caution in terms of interpreting some of those model results you were speaking of before about how, you know, IRM minus one in relation to IRM plus one in terms of what's coming out of the simulation results. And just to point out that, while those results can vary significantly depending on what you assume in the model for bidding by existing capacity and new entry, what prices assume that they're bid in at. And to also point out that there's a lot of volatility in the results, which is to be expected.

And so when you're looking at those average numbers you should also be thinking about the fact that there may be a pretty wide band around those averages.

MR. MEAD: Are you disagreeing with the notion that there's basically a declining marginal reliability to capacity?

MR. WALLACH: No, no. I'm just saying -- I interpreted what you were saying before as that you were looking at, you know, some of the model results that were coming out. And I'm just saying when you look at those results, you know -- a grain of salt.

MR. CHOUEIKI: Can I add one thing to this?

MR. MEAD: Can we get Matthew and then --

MR. PICARDI: Dick, when he asked the question, kind of triggered my memory. And it reminded me that when the demand curve was first proposed in New York -- and I'll attribute it to Thomas Painter at the New York Commission he called it the ICAP Willingness to Pay Curve. So I pulled this paper which I had with me to kind of see what he was saying, if he was addressing what you had asked.

And really in reviewing it what I think his analysis was is that the demand curve represents the customers' willingness to pay to reduce volatility into -- as a way of dealing with mitigation of market power.

So I'm not sure that gets it in terms of what are they willing to pay for reliability and how often their lights go off. But he expressed it in terms of what am I willing to pay to reduce volatility and deal with market power.

MR. O'NEILL: Well, I mean demand bidding does that too. It's a related topic.

MR. CHOUEIKI: What I wanted to add to his comment about the simulation results are the simulation results demonstrate that if you were to compare an eastwise downward sloping linear curve to a vertical curve, consumers are better off. And, of course, there is this very large variability and uncertainty.

It does not say that RPM, consumers are better off with RPM than with ICAP. It just talks about the curves. RPM has other -- it's a bigger concept than just that curve.

MR. MEAD: Ben and then Esra.

MR. HOBBS: I think I just wanted to clarify. I think what you're getting at, Dave, is that when there's variation --

MS. COCHRANE: Can you turn your microphone on, please?

MR. HOBBS: Sorry.

When there is variation in the realized reserve margin that you get variation loss of load probability. The loss of load probability is a non-linear function of the reserve margin. And because it's a convex function on average you'll need to actually have reserve margin that's above the IRN if you want to achieve on average one day loss of load.

And how far you have to be above that depends on the shape of that curve, which is somewhat speculative and also depends on how much variation you would see in reserve margins, which in part depends on the shape of the curve. So I think that's the only -- we weren't yet talking about the specific assumptions. I think it's the general principle you're articulating.

MR. MEAD: Esra.

MR. HOUSMAN: Yeah. With regard to what Andy was mentioning earlier, I agree that maybe one of the benefits of having some sort of a system like this would be to provide incentive for demand response. And so -- and I believe that it may in fact be more effective at that than actually creating incentive for new generation where it's needed.

I wonder, however, why if demand response is the more likely source of reliability, why we would be basing the curve on this hypothetical cost of new entry for a generator whereas we might look at the marginal cost of additional demand management or conservation.

And I would also note that that demand response was not included or represented in any way in the model that was used in order to analyze these curves, and that in fact

-- I actually have spent a lot of time reviewing the model and I have prepared a two-page summary of some of the ways in which I feel the model does a poor job of representing the reality of incentives and generator response, which I have left a number of copies out on the table and I have a few copies to share, including with anyone here who is interested.

But I think this is certainly a very important area, that if we expect demand response to be a part of this, the reliability solution, we should be gearing the curve toward that and analyzing the curve with that as a consideration.

MR. MEAD: Are you then recommending that we should base the demand curve on some estimate of the customer's relative values for different levels of capacity and reliability rather than basing it on cost?

MR. HOUSMAN: Well, since you asked, my recommendation would be not to have an administratively determined demand curve at all. But I believe that one that included the value of electricity to consumers, of the reliability to consumers as opposed to just being based on purely a generation solution would be more reflective of where capacity prices should be.

MR. MEAD: Does anybody else on this panel share that view?

MR. CHOUEIKI: I would even add go further and say that the simulation results are limited in scope just because that's what PJM instructed their consultant to do. I think we could -- my recommendation -- I'm very familiar with the model.

We even ran all the sensitivity analyses that were done by Professor Hobbs and went on and did another 64 runs by changing simultaneously several of these factors, such as risk, growth in demand. I mean basically everything that we can do sensitivity analyses we altered and measured simultaneous effects and main effects basically of all these variables.

It's very limited in scope because it only takes generation solution as the solution to the complex problems that we have at hand. There are transmission solutions, demand resource solutions that were not included in the model.

We're trying to assess here RPM as a whole, an entire process. So we're getting bogged down with the demand curve, which is basically either a linear curve or a vertical curve, and that's it. And we're then taking only generation as the solution at hand. So it needs to add transmission. It needs to add somehow -- Now of course PJM went in in there paper hearing and responded of how they would tie in transmission solution into RTAP and RPM.

But basically we would like to see it in simulation before we have an opinion on it. Right now the only thing we see is generation solution, a linear demand curve, and consumers are better off.

MR. MEAD: Those are good points.

I'd like to hold off on discussing the implications of that at least for a few minutes. I'd like to sort of focus a little bit more in the remaining moments that we had devoted to this particular topic to should we base a demand curve on an estimate of customer value rather than the cost of new entry, whether that's generation or transmission or whatever. And if we are going to base the demand curve on an estimate of customer value, how would you go about estimating that value?

Esra, you seem to have some ideas on how you would do that. And we probably don't -- we definitely don't have enough time at this session to fully flesh that out But if you could talk a little bit more about it and supplement the record in the post-technical conference comments.

MR. HOUSMAN: Yes, we will certainly do that.

I feel that the current system is somewhat more reflective of consumer value because in fact, as was illustrated in Mr. Wallach's affidavit, there is in fact a demand curve through the process of bilateral trading, which he can speak to more if he's eager to do so. So that would be I think closer to the solution. But I think I'll turn over the floor.

MR. WALLACH: Well before I get to that I actually wanted to tie together the two comments in response to your question as to whether, you know, what should the demand curve be based on.

\And I think the gentleman over here made a very good point that we should not lose sight of, which is that there are several elements to RPM besides the demand curve. And most importantly, the most important element is the forward procurement aspect. Specifically an element that allows new entry to participate in the auctions.

And the reason that's important is because as they eventually recognized in New England, the settlement process is -- it's the forward procurement element, the ability of new entry to participate in the auction and set the price, that's the key factor, that's the way you get to price stability. And so it may in fact be that you don't need a demand curve, per se. I mean if you're going to do forward procurement and you're setting an IRM you're going to have in essence a vertical curve or some variant on it.

But you don't have to try and shape a curve, a sloping demand curve to reach some, you know, promised land of long-term equilibrium when you've got a supply curve which is very stable and where the outcome of the auction is going to fluctuate very tightly around a stable price -- that being the cost of new entry -- as it is determined in actuality by bidders, by suppliers offering in. And I really want to make sure we don't forget that because when we're thinking about, well, how do we, reach IRM, how do we get price volatility, how do we get price stability, how do we, you know, get adequate, you know, returns to generators at lowest cost to consumers.

I would suggest it's not the demand curve that we need to be focusing on, but this aspect of being able to get new entry, new projects, the ability to offer into the market.

MR. O'NEILL: Can I ask one question before we leave this topic?

As I understand these models, the estimated reliability criteria, as I think Andy said, is one event in ten years. If that is the case, does the model differentiate between let's say the lights going out here at FERC for the rest of the day and us losing the value of this conference and the blackout in 2003.

MR. HOBBS: I'd like to address that in general.

Given a reserve margin one can make a loss of load probability calculation based on all sorts of assumptions, including independent outages of generators, not considering cascading outages.

As all the classic texts on reliability point out, reliability is an ordinal measure. You can say that one system is probably more reliable than another. But it's not a cardinal one in the sense that we really know that, yes, it will only happen one day in ten years because there are common mode failures. These models don't account for operator responses which can mitigate some of the risks, and they certainly don't account for cascading outages.

So at best these reliability models, when they say one day in ten years, they say, well, relative to a system of two days in ten years it's more reliable.

So we cannot take the output of such a model, slap a dollar per value of lost load to that and then create a curve that shows us how much the reserve margins have used and use that demand function. The reliability models are just simply not of that quality. They do not differentiate between just the value of losing this conference, which might be small or might be large, might be positive, might be negative, versus something affecting the entire East Coast.

And certainly in our modeling we haven't done any of those calculations.

So I guess I'm speaking vociferously against using a VOL type of curve. I'd rather say what sort of reliability standard we want in terms of LLLP and then figure out a way of getting there.

And meanwhile, of course, we try to improve reliability analysis and see, well, maybe we don't need one day, maybe two days is enough. But make that a separate analysis.

MR. O'NEILL: If that's the criterion, could you make the system more reliable by splitting it in two?

MR. HOBBS: I don't understand the question.

MR. O'NEILL: Well, if a large system is let's say out of reliability with the one event in ten years, that event takes place over a large system. So if we take the system and split it in two, both remaining systems would potentially be in sync with the one event in ten years.

MR. HOBBS: Oh. Okay. So in terms of coincidence of it, the frequency may go down.

MR. O'NEILL: One event.

MR. HOBBS: That's right.

MR. O'NEILL: I'm not talking about the number of megawatts.

MR. HOBBS: And these are the sorts of discussions that you get into in trying to assess the reliability of the system and many of the ambiguities.

MR. CHOUEIKI: It depends also if those two systems are completely independent.

MR. O'NEILL: I realize that it can get very complicated in terms of how interactive they are. But in -- just as Andy is a statistician, he would understand if splitting the thing apart may essentially just simply make it reliable.

MR. HOBBS: I should point out that the editor of the classic IEEE test on reliability analysis is in the audience, if you want to have a further discussion about that. I'm sure Dr. Bobarashu can tell us more about what we can infer from these sorts of studies and what we can't.

MS. COCHRANE: Before we go on to the next topic, does anyone else from Staff have any questions?

MR. GOLDENBERG: Yeah, I have one question.

Just as a lawyer, do we have any idea from any of these analyses what the magnitude of the change for consumers would be if we adjusted the curve this way or that way? We've heard that there have been various simulations. I think it would be somewhat useful to know what would happen.

MR. HOBBS: So a simulation model calculates a number of different indices that folks might be interested in. And one of them is average consumer cost, including both scarcity costs and the cost of the capacity market. But it's an estimate of those that depends on certain assumptions which, as other folks here pointed out, you change the assumption you'll get different numbers.

The point of the analysis, though, has been to see whether some curves are robustly better in terms of consumer costs than others, no matter what the assumptions are.

MR. HOUSMAN: I would say that we did an analysis on behalf of the Coalition of Consumers for Reliability comparing the proposed system with the VRR curve to the existing capacity market prices in PJM. And we found that it will cost consumers several billion dollars a year, PJM-wide, in additional costs.

Now this is -- I don't think anybody on the panel is going to disagree with me because they refer to this as the 'missing money.' We refer to it as the consumers' money.

(Laugher.)

MR. HOUSMAN: And when they do, in fact as Mr. Stoddard referred to this revenue shortfall, of course we have to remember the revenue shortfall only refers to a small number of peaking generators that are actually -- we're trying to --

MR. GOLDBERG: Was that done regionally? Is it the PJM model now worked with the regional --

MR. HOUSMAN: Well, Mr. Hobbs' model is not regional. It's PJM-wide.

Right?

It's not divided into any subregions.

MR. GOLDBERG: But the proposal in RPM was to do --

MR. HOUSMAN: The proposal at RPM, yes, the proposal at RPM is to have different locational demand curves.

Each of them would have a target of IRM plus one percent. And at IRM plus one percent the cost of new entry would be the capacity cost, which all of the generators in the region would receive. So that if all of the areas of PJM on average were at IRM plus one percent then the capacity price throughout PJM for every megawatt of capacity on the system would be the cost of new entry of a new peaker.

Does anybody disagree with that?

MR. ANDREW OTT: Yeah, I disagree with that.

MR. HOUSMAN: Okay.

MR. O'NEILL: I think the key here is to -- again, the analysis you're referring to is comparing, you know, the capacity cost we have today, which, you know, we all recognize is a broken system. And it's also, you know, looking at the capacity price for the recent year or past year.

If you actually look over time back into the 1999 time frame and start looking at what the prices of capacity were back then and average it over time, you also look at the locational components of RPM and, you know, the way the power transfers across the system. Essentially the $12 billion rapidly comes down substantially because you're actually -- if you look at what capacity has been over a period of time and what the price was as opposed to just looking at the absolute lowest time, you know, that we're in now, it's a totally different picture on what comes out there.

MR. HOUSMAN: Well, okay. But that does not address the fact that this would be paid to every megawatt, including every nuclear and coal megawatt that is currently on the system.

MR. O'NEILL: Yeah. Now let me be fair --

MR. HOUSMAN: And let me just add that that's if you believe that the model would work as it is projected to work -- that the RPM model would work as it was projected to work in the VRR curve model by Professor Hobbs.

But, as I said, we have many concerns about that and concerns especially about the fact that the model has not been, you know, validated or particularly audited or cross-examined. And I do, please, encourage people -- including Professor Hobbs -- to have a look at our concerns about how well it comports with the realities of the market.

And I think it's very important to have those concerns be addressed because what we fear will happen -- and I think the reason that consumers have been overwhelmingly opposed to this proposal -- is that we fear that in fact capacity prices will go up. It will not have the intended effect on improving reliability. We'll end up below IRM with the twin perils of very high capacity prices and inadequate reliability. And that is absolutely a possible outcome of this system if the prices -- if the obstacles to investment in capacity are not purely financial obstacles. And I think the electricity market we all know that the obstacles go far beyond simple financial obstacles.

MR. O'NEILL: You're representing Consumers?

MR. HOUSMAN: Yes.

MR. O'NEILL: How fast can they become bidders in the system?

MR. HOUSMAN: Can they become bidders? You mean to bid their --

MR. O'NEILL: Yes. Let's say in the day-ahead market they could bid in, or the real-time market. How fast could we get them in the system? We can maybe solve this problem really quickly.

MR. HOUSMAN: I think that's an excellent question.

I think the problem is that generators own a much larger share of potential capacity than the consumers do. But I think that if we can get them into the system then we will have solved the problem.

MR. O'NEILL: Right. How soon?

MR. WALLACH: We have a few technological constraints.

MR. O'NEILL: Well, I mean how soon does it take to overcome them?

MR. HOUSMAN: What's that?

MR. O'NEILL: How soon does it take to overcome them?

MR. HOUSMAN: Well, we haven't overcome them yet although there's been an awful lot of talk about it. I'm not an engineer. All I know is that it will take long enough that the cost impacts that we're talking about will occur because we're talking about RPM within the next year. And I don't know how long it's going to take to make these changes --

MR. O'NEILL: Well, my problem is will we be talking about the same issue five years from now?

MR. CHOUEIKI: We have to have smart metering. You know, once you have smart metering people are starting to look at it. In Ohio I think we have a person on staff who is really looking at the technology and what's happening. So it's a long time before we get there.

MR. MEAD: Before we hear from Mr. Stoddard, Mr. Housman, you said a moment ago that the problems of investment are not merely financial. Are they partly financial? Are revenues right -- Assuming you got rid of all the non-financial problems, in your view are capacity prices high enough today to elicit adequate investment in all the places that they need it?

MR. HOUSMAN: I'm trained as a scientist. I look at empirical data. And I see that in all places where the structural impediments are not preventing new capacity we have an abundance of capacity. So the only areas where we don't are the ones where there's inadequate access to sites, you know, and other structural issues.

There's also an issue of long-term -- the assurance of long-term revenues is a problem. But again, the RPM system as it's proposed only guarantees one year of capacity prices.

And, please, believe me, we don't want to lock in these prices for long term because they're going to be too high. But we feel that, you know, long term contracting -- I feel that long term contracting certainly would be helpful. I think that, you know, that essentially the evidence shows -- as opposed to what the model shows -- what the empirical data show is that financial obstacles are not the primary issues.

MS. COCHRANE: I'm wondering if we have exhausted the height and slope of the demand curve and whether it should be based on new entry. If we have exhausted those questions maybe we can -- we have a number of questions to address today.

MR. MEAD: Yeah.

MS. COCHRANE: Are we ready to go on to --

MR. MEAD: Let's move on to cost of new entry.

The first question, I guess to Mr. Pasteris, Mr. Parker in his comments states that PJM's estimate of the cost of new entry is significantly below that used in New York in developing its demand curve for the rest of the state.

As a general matter, do you think the cost of entry in PJM is significantly below what it is in New York's rest of state region? And therefore is that something that we should be concerned about in examining which estimate of cost to new entries is proper?

MR. PASTERIS: Well, I guess I can say that based on how the cost was developed in PJM, which is where we asked the Wood Group to develop a capital cost estimate based on -- in 2004 based on if they were planning to build and construct a plant of this design at these locations, that's the price that they provided to us.

Now I can't say that if we asked them to provide the same type of cost estimate in the New York region up in the rest of the state of New York exactly what price they would arrive at. They could arrive at something very close to the PJM price.

It could be higher, it could be lower. We don't know. So I can't really state whether the price in the rest of the State of New York is legitimately higher, based on how I would have done, or how PJM would have done the process.

MR. MEAD: Does anybody else have a view on this? Do other people think we ought to look at the cost in New York and evaluate that cost relative to the cost in PJM, just in terms of determining whether, you know, what we're really interested in, which is the cost in the various regions of PJM is accurately set?

MR. STODDARD: Allow me to interject. I don't have a firm opinion about who's got the right number. I think what we learned, though, by seeing two honest attempts at coming up with the same number, and then coming up with numbers that are different by more than a factor of two, that there's a great deal of uncertainty about what the right number is.

So when we have to think about designing the curve, we have to think about what is the goal. The Commission has found that there is an imminent risk of reliability violations in key parts of PJM, including where we are sitting now today.

So the question we have to ask is what number do we need to put into this curve to have reasonable assurance that we have enough investment where it's needed?

If Ray is right, then the number could be low, but if Seth is right, the number might be much higher. The trouble is, if we put in Ray's number and it turns out Seth is right, we don't see investment. We have reliability violations.

If Seth is right and Ray is wrong, we get perhaps more response than we need, and provided that we have a mechanism, which I proposed, of dialing back or dialing up the cost of new entry, we can limit the impact of misestimations and CONE based on market performance.

Right now all we have is expert reports. We should use a conservative number, that is to say one designed to conservatively respond to the need for new investment, and then make sure we have an automatic tracking mechanism built into the market design, to move that estimate based on market response starting in Year 1, and all through the stakeholder processes looking at it.

MR. HAUSMAN: And I just have to add that if I'm right, and we use Mr. Parker's numbers, then the cost to consumers will be much higher than even I have estimated earlier, and that's for several years, even if we have a dialback mechanism, which means perhaps tens of billions of dollars.

MR. STODDARD: Yeah Seth. Go ahead.

MR. MEAD: In considering -- in getting ready for this technical conference, I started weighing the validity of not so much the Pasteris estimate versus what we had prepared for New York ISO a couple of years ago, but looking at, instead of paper estimates, what I would call more real world estimates, as embodied in the reactive power filings.

I became myself more convinced that if you do have to establish a cost of new entry, regardless of whether we have a dial-in or dialback mechanism down the road, that you still have to estimate it as best you can.

And I went back to the filings and tried to confirm whether all the capital costs, and this was a key issue, were incorporated in those filings or not. This goes back to an AEP filing and the FERC order in that docket, that identified which costs should be incorporated and which ones should not.

Then secondly, I went to the reactive power filings themselves, and in fact there were four filings that identified which costs were in fact proposed, included in those filings, and which ones were not.

I absolutely concluded that again, number one, it's better to rely on these hard factual filings rather than sitting at a desk and developing an estimate on paper, and number two, that in fact certain adjustments need to be made, to correct for perhaps economies of scale if the plant has more than two units, more than the reference plant that was established by PJM.

If the commercial operation data is not 2004, and in particular if capital costs needed to be added in because they were not included in the reactive power filing, I have a handout that I'm willing to circulate if it's useful, that demonstrates the AEP filing, as well as the -- I'm sorry, the AEP Order, in which capital costs should or should not be included, as well as the four reactive power filings that identified the capital costs that were included, to support this position.

If you'd like, I'll pass them out. I have enough copies. Otherwise, I'll just have them available later.

MR. STODDARD: Sure, why not.

MR. MEAD: Okay. I'll provide them to you. You can pass them out half of them that way, half of them this way, and once you get a copy I'll just point you to the right place.

(Pause.)

MR. STODDARD: Just where do these reactive power filings come from? Are these the ones they file to get their reactive power payments?

MR. MEAD: That's exactly right. So the first two sheets is a FERC staff report dated February 2005, that references on the flip side of that sheet Opinion No. 440

regarding the American Electric Power Service Corporation.

I've also attached Appendix E that's referenced in this document, and may I turn your attention to the second sheet of Appendix E, entitled "Application of AEP Methodology to All Respondents to Form 1."

This was the calculation that AEP submitted, and near the bottom of that sheet, there are two percentages that stand out. Well number one, I won't take you through it, but this demonstrates that basically the costs that are included are number one the generator and its exciter; number two, accessory electric equipment that supports the operation of the generator exciter; and number three, the total production cost investment required to provide real power and operate the exciter.

Production cost investment is defined pretty narrowly. If you go now to that table on the second part of Appendix C, there are two percentages near the bottom. One is percentage allocated to reactive power, 21 percent.

That number is key. This is where the applicant's reactive power filings get the bulk of their revenues. They look at the total generator plus exciter plus accessory electric equipment, and 21 percent of that gets allocated according to this formula.

The remaining plant costs, what's referred to as production plant, you can see in this number. It's $209 billion. The overwhelming majority of the plant cost only has an allocation factor of 0.15 percent.

I confirmed in a conversation with the consulting engineer for the four reactive power filings that I mentioned, that it wasn't worth the potential litigation involved for the owners of these peaker plants to try to incorporate the total capital cost, because it provides so little bottom line revenues when the allocation factor is so small.

So again, for the four reactive power filings that I've found capital cost data, they've included what I would more or less describe as the power island, turbine generator and related key equipment.

It does not include off-site costs, soft development costs, unessential production costs, again because relative to the dollar benefit that they get using that 0.15 percent allocation factor, it was not enough dollars to take the risk that there would be litigation and hearings.

The other part of the handout again is just --

MR. O'NEILL: What kind of plant is it?

MR. MEAD: These are all peakers.

MR. O'NEILL: The $209 billion?

MR. MEAD: Oh no, no. I'm sorry. This was AEP. They had a total system application.

The other sheets are the cover sheets for the four reactive power filings that I've referenced, and then on the backside of each are the capital costs.

You can see by looking down through the equipment, that again they're basically just submitting what I would generally call the power island. So that there really are missing capital costs that would have to be included in a proper calculation.

MR. PARKER: In your May 30th comments, let me just verify that we're talking about the same thing. You said that there appears to be missing from the cost recovery filings a bunch of costs including electric and gas interconnection, project development costs, land ownership costs, spare parts, startup training and testing.

Are these the costs you're referring to? You said "appear."

MR. MEAD: Right.

MR. PARKER: Do you really make sure, are you pretty certain?

MR. MEAD: At that point, I was hedging my bets.

MR. PARKER: I'm sorry?

MR. MEAD: At that point, I was hedging my bets, and at this point I'm convinced that -- I'm certain that those costs are indeed missing.

MR. STODDARD: Okay. Mr. Pasteris, you -- as I remember your comments, you took issue with the fact that these costs were in fact missing. Did I understand you correctly? Do you disagree that these particular costs are missing from the filings?

MR. PASTERIS: Well, we took the filings that they tell you, that there was every incentive for a generator to present the full cost of this plant, and that in going in for a reactive filing, and that certain costs, soft costs, could be allocated into various categories.

In other words, they could allocate the cost of off-sites and soft costs into the various other categories. There wasn't any specific category under the FERC categories that said that they were not allowed to put these costs into these specific categories.

So based on that, you know, we took the cost of the plants at face value, and as a -- not as the basis for our cost estimate by any means.

Our basis of our cost estimate remains with going to a company in 2004 that if any of the generators ask them to deliver the cost of this particular cost of new entry in 2004, would build that plant for them at these locations for that price.

What we did to kind of look at that number and decide whether it made reasonable sense is that does this look like a good number? We looked at the reactive filings and said based on what we're seeing from the reactive filings, it looks like it's a good number. So it's a very good number.

So it wasn't -- our number is not using the reactive filings as a basis for any necessary adjustment to it. It was just a bump check as to what we were getting from the Wood Group, and then the allocation of additional costs placed upon it.

So we stand behind our estimate from the Wood Group, as well as I've done a bit of further investigation, and I think two generation companies would view Mr. Parker's costs as being high and that's Alliant Energy and Wisconsin Public Service, which recently put on line an exact duplicate configuration of the -- our cost of GE-7 FA engines in Sheboygan Falls, Wisconsin.

The cost of that facility was $141 million, which puts it a number of million dollars under the cost of our facility at $159 million in Illinois.

So there is actual. Aside from the FERC filings which we used as kind of just a check of our number, there is actually a facility that just came on line near -- just 100 miles north of our Chicago site, that came in at very comparable and even appears to be lower.

MR. MEAD: I'm sorry. This Chicago area plant has been built or --

MR. PASTERIS: No, no. Yes, this one, the plant in Sheboygan Falls, which is about 120 -- about 100 miles north of our cost of new entry site, Northern Illinois site in our PJM.

MR. ANDREW OTT: If I could clarify, we asked them -- PJM asked him to take reference sites and calculate across the new entry, and the Northern Illinois site he's referring to is he picked a location in Northern Illinois for us and did a reference check, I assume, with the Wood Group.

So the Northern Illinois site is not a site where we actually built -- anybody built a plant. It's our ref. We asked him to equate the cost of new entry and give us an estimate of that site.

Then he's also -- he's referring to this Wisconsin which was an actual build, so that was really sort of validation.

MR. PASTERIS: Okay.

MS. KRAMSKAYA: I'm sorry. May I ask a question about the reference sites? How were those selected and why were those selected, the three specific sites, and are they good proxies for the regions?

MR. ANDREW OTT: Yes. Essentially we -- Ray can get into the detail about what various cost parameters would tend to vary by location. In other words, what stuff would be more standard and what would vary by location.

But what we were interested in as PJM is getting, you know, a diversity of sites, a few sites around our footprint, to get a representative estimate. We didn't think we needed to do it in every single, you know, state or location or delivery area.

We just wanted to get a sort of a balance. So we wanted a site in the eastern part of the market, a site in the western part of the market, and I think we had one near the middle.

So we're just trying to look at -- and when we actually saw the results coming from Mr. Pasteris, they were so close, you know, that we said, you know, since there wasn't a lot of difference in the CONE across these various sites, we felt reasonable -- it was reasonable to stop at three, to get sort of an east, west and central.

So that was really the basis for the discussion. We started out asking for the three. Obviously, if it had come out with a lot of diversity, we may have gone further, but it in fact didn't.

MS. KRAMSKAYA: So one follow-up question. So was the specific Southern New Jersey site chosen by PJM?

MR. ANDREW OTT: Yes, yes. Myself and Mr. Gowery.

MR. PASTERIS: To follow up on that, one of the points that I've made in my pre-file is that that's a bit concerning. We had a clear need for new resources in certain urban locations, particularly Northern New Jersey.

It's not clear to me, although I've read argument about why that shouldn't be more expensive to build in Northern New Jersey than in Southern New Jersey, but it would have been nice to have tested that.

When the studies were done in New York, the cost of building in New York City, which has a very similar urban density to Northern New Jersey, were substantially higher than building in upstate New York.

If we are going to have a constrained region that includes -- that is targeted at Northern New Jersey or for instance the metropolitan corridor here in Washington-Baltimore, it would have been nice to have benchmark reference prices, so that when those regions are constrained, we have confidence that the demand VRR curves in those regions reflect the actual cost of building in those regions.

MR. WALLACH: Just two comments in response to that. One is that my recollection and understanding is that the capital cost for new GT in New York City was so much higher than for the rest of the state, was because it was a different technology.

Secondly, there is no place like New York City in terms of cost structure. It's just a whole different ball game.

That said, the only point I want to make is that you can choose lots of different areas for how to price out the capital costs. You can do it in the general areas like PJM does or maybe you want to have it specific to it, the particular LDA.

However you do it, it's important to recognize that well that this the net cost cost of entry. So if you're talking about a capital cost for a location in Northern New Jersey, you should also be counting your net revenues appropriately for that location.

MS. COCHRANE: Ezra had his card up and then Debbie has a question.

MR. HAUSMAN: Well, I just wanted -- I was interested to hear that the plant in Wisconsin came in in fact lower than Mr. Pasteris' original estimate.

I note that in your affidavit with the RPM filing, that all of the plants that you had found, the recent builds, were actually lower in cost than the estimated cost of new entry by 67 to 75 million dollars.

Now you attributed that to the -- at least part of that to the absence of SCRs and fuel switching capability, and so you felt that made up about $50 million of that difference.

Mr. Parker then feels we should add another set of SCRs and fuel switching capability in your comments from May 30th. That was one thing.

MR. PARKER: You probably misconstrued my comments.

MR. HAUSMAN: I'm sorry. But in any case, I guess I'm curious as to why we wouldn't take a look at these historical data, if we were going to estimate the costs of new entry and actually use those as an estimate, which after all, what the market has produced as opposed to what modeling analysis would produce.

I also feel that specifically with respect to those technologies, a proxy peaker plant should not consider SCR and fuel switching capability.

Now we do a lot of environmental work. We're very much in favor of real SCRs on real plants that generate electricity. But the market realities are that peaking plants, which are only going to run a few hours per year, are very unlikely to include these technologies.

MR. PASTERIS: Can I respond to that? Your cost numbers just don't seem consistent with mine.

We're looking a total plant cost for the two engine plants, which includes SCR NOx control technology and dual fuel capability, and also turbine inlet air cooling, which helps sustain the output of the plant under high ambient temperature conditions, of being about $157 million.

If we remove the SCR technology from its deduct of about 13 million, and the oil firing capabilities, a deduct of about $4 million. So that's the -- you were mentioning like $50 million. That was the --

MR. HAUSMAN: Okay. I may have had the numbers slightly wrong. But still there was this difference of 67 to 75 million dollars between the plants that you had -- I'm sorry I don't have your original affidavit with me, but you had a list of recent builds in PJM, and they all came in at a lower cost.

MR. PASTERIS: That was the reactive filings numbers. I'm assuming that they don't have dual fuel capability, which I believe they don't, and SCR technology.

Then if you look at our cost of new entry and then look at the reactive filings, and then add to them the cost of SCR and the cost of oil firing capability, and it came out to be just short of our capital cost number on the average.

So that was kind of our bump check of those -- of that number. So --

MR. HAUSMAN: My concern was just that it included those two capabilities, which I don't think were realistic, and then in addition, it still came out a little bit charred. So that --

MR. PASTERIS: You know, the siting of a -- you know, when a power generator or a developer is looking for a site, he's going to be looking -- he's kind of playing all of the various options.

He's looking for a location that's close to the high voltage lines. He's looking for a location that's close to the gas lines. He's looking for an area where the labor costs are low. He's looking for an area where the property taxes are low.

So there's kind of an innate optimization going on in a sense of when, you know, a developer's looking to site a plant, as well as the issues of closer to an urban area, there might be more emissions controls required.

If he moves outside of those urban areas, there might be some leniency on emissions controls. So though there doesn't appear to be any recent peaker plants built with the SCR technology, it's at this juncture going forward if someone's looking to build close to an urban area or maybe even remote from that, it's a high anticipation it will be called for. That's why it's in there.

MS. DEBORAH OTT: I just have a question to make sure I understand some of how these cost figures are coming together.

Initially, the RPM is proposing to define two separate regions. So there would be two separate demand curves that would be in play. Is that --

MR. ANDREW OTT: I think the original filing contemplated a two-year transition, where we have, you know, one year where we have the two locations, and the next year would be four LDAs, and then the next would be whatever. It would be the potential for 23.

So I think because we're -- because of the procedural schedules, I think that first year where there's only two would drop away, because we've already delayed a year.

So the first year would actually have, I believe, if I'm recollecting, I believe it's up to four LDAs. That's a transition. But yes, there would be a few locations in first year.

MS. DEBORAH OTT: So the estimates that, the sites that you chose are the ones that would apply to those four separate regions that would be initially in play in the beginning?

MR. ANDREW OTT: Correct. The appropriate CONE references, for instance, the one in Chicago, would be the region out to the west. The one in New Jersey would be the region to the east.

MS. DEBORAH OTT: Okay. I just wanted -- so that's the -- when Tatyana pointed to the fact there were three sites, those are the CONEs that would be used to develop the demand curves in those separate --

MR. ANDREW OTT: They would be the reference. And again, since there wasn't a lot of difference between them, we didn't, you know, go through the exercise of calculating, you know, thirty of them, because we didn't see a lot of variation. And again, the different costs could vary. I assume Mr. Pasteris could talk about that when he deals with the next area, to go through that.

MS. DEBORAH OTT: So for example, in the eastern region, the New Jersey site is intended to be in some sense a basis to represent costs throughout the entire eastern region?

MR. ANDREW OTT: Right.

MS. DEBORAH OTT: Okay.

MR. STODDARD: I wanted to sound a note of caution about taking ex poste capital costs we can observe, and drawing too straight a line of saying well, there's a deviation of a few million here or this.

There are -- it's an important difference of saying well what would it have cost to have built? If you have a successful entry, we can go back and look at the costs. Ex poste, we know what they were.

What we're trying to do in this market, this cost of new entry number, is to try to estimate what bid a potential new entrant would need to be able to clear in the market, in order to be willing to undertake prospectively this development.

Now that means he's taking on not only all the ex poste costs that we observed in the filings, but also a large number of risks. What if that project can't get permitted and sited?

He has an obligation to PJM to deliver capacity, that he has to figure out how to unwind. What if various costs are higher? Any rational developer has contingency costs he builds into these projects, which after the fact may or may not have been realized.

Prospective costs include risk adjustments, include contingencies, include delays that have to be budgeted in, that these ex poste accounting analyses miss.

So I think any number built on a bottom up from an accounting perspective like this, without having made those adjustments, will tend to be a little conservative, potentially a lot conservative,
on what kind of bids people will need to make into this market in order to be willing to participate.

MS. KRAMSKAYA: Can I ask a follow-up question? If we were to have adjustments for, as I understand, competitive bids in the market, would that be the highest bid or an average of all bids by the new entrants, or how would you estimate it?

MR. ANDREW OTT: I would tend to look to the highest clearing bid. So obviously if you had ten projects and three were needed, then it would be that third one in the queue that you'd be looking to as a benchmark project.

MS. KRAMSKAYA: And what if there were no new entrants?

MR. ANDREW OTT: Ahh. Well then you probably have learned -- well, if there was a need for them but no one offered, that sends a real red flag about what your cost of new entry estimate was, and we probably need to go back and do something more drastic than that.

But if the market fails to clear at all, then we have, you know, we probably have gotten CONE wrong by a factor of two.

MR. HAUSMAN: Or it means that the obstacles to investment are not financial.

MR. ANDREW OTT: Yes, if I may point out, you know, I think if we all -- as we talk about these items, I think another feature, you know, just probably good to understand of the RPM proposal, includes an assessment, you know, I think it's set at this point in the model, proposed to be every three years, where it actually does.

For instance, if we had something where we didn't have new entry or even, you know, just as a matter of course, we have a review of these parameters.

In other words, at the third year after we've had three years of experience with the market, we would do an analysis that would look at, you know, did we have issues with new entry, revalidate the new entry.

In fact, during that process, we could even start to utilize actual operating data that came in. So I think embedded in this model already, and you know, it certainly could be enhanced, is this ongoing performance analysis that could tune up.

So really this CONE estimate, I think, you know, it's -- its value is in these first years, and I think that, you know, from -- as the PJM stakeholders discuss this, I think stakeholders took a lot of comfort from the fact that we have these ongoing evaluations that we reported back to FERC and to the stakeholders about what in fact is going on.

So that you didn't just put it in and say "Now we can all sleep nights and go away. There's actually more to it.

So as we discussed this, we need to all recognize that, because it's not -- you know, it's not a finality about it as much as an ongoing assessment.

MR. HAUSMAN: And is there a refund mechanism as well as a reevaluation mechanism every few years?

MR. ANDREW OTT: No.

MR. WALLACH: Can I take the question as a consumer rep? If they really believe that this model is going to produce prices way too high, couldn't they avoid those prices by just simply signing long-term contracts with generators to build their own generators, and then essentially take advantage of this market? What are those impediments?

MR. O'NEILL: Well, Dick, I have a two-part answer to that. First of all today, most of the activity is not in the PJM capacity market. I think the PJM capacity market represents a very small share of the capacity market in total.

MR. WALLACH: So load is presumably already, and obviously none of that information is public, but presumably already meeting its obligations through some form of bilateral contracting outside of the PJM central market.

Second of all, we can't ignore the fact that in theory and it appears from, you know, what evidence is out there, that pricing in the bilateral market is affected by what goes on in the spot residual market.

That's the way it's supposed to work. That's why you have that residual market, to provide that transparent pricing information. So what goes on -- that's why we're here and why we're concerned.

Even though it's only, you know, a tiny share, the way it is today. I mean obviously, you know, with RPM, with a mandatory centralized option, everybody's thrown into the auction, although you can do bilateral --

MR. O'NEILL: But you can be on either side of that.

MR. WALLACH: Right. But the point is that we're concerned about it because the prices coming out of that residual auction do affect what's going on in the bilateral market.

MR. O'NEILL: But my question was, is that if these estimates are out of synch with reality, then the customers should be able to get into the long-term contracts and take advantage of it, and be on the other side of the market if they really believe that.

MR. WALLACH: Well, I mean are you suggesting that You can get a better deal on the bilateral market?

MR. O'NEILL: I would think so.

MR. WALLACH: Perhaps you may be able to negotiate a better deal, not necessarily as good a deal as if the price signals coming out were lower. I mean, you know, that's why you engage in bilateral contracting, for a number of reasons, you know.

If you're doing bilateral contracting because you want to, you know, shed the risk, you want to, you know, enter into something longer term that's offered, then what's offered in the residual auction, a lot of different reasons.

So you could in fact pay more in a bilateral contract than you would get in a spot auction because of, you know, your sense of risk and risk aversion.

MR. O'NEILL: So then you're not really sure that these costs are too high. The sense of risk means that they may not be as high as you thought they were.

MR. WALLACH: To certain parties, it may not be too high. To other parties, it's too high.

MR. HAUSMAN: I think John's point is that the bilateral price will reflect the expectation of the capacity market price. So the bilateral price may be higher if RPM were in place, and there were an expectation that the capacity price would be the cost of new entry or higher than the cost new entry.

But it's unlikely that anybody's going to enter a long term bilateral deal for less than that. Is that -- do I understand your point?

MR. WALLACH: Right. With the same -- you know, for the same product. You know, if you're buying --

MR. O'NEILL: So the generators are going to withhold themselves from the bilateral market, to take advantage of the PJM-RPM market?

MR. WALLACH: Well, they're certainly not going to enter into any market. They're not going to offer their product at a price below what they perceive to be the likely real time market price, except there were maybe certain circumstances. If they're trying to fund an wind farm and they needed to have long-term funding.

So there may be some fluctuation around that expectation. But that would be what anchored the expectation of the price. So it would be what anchored the forward price, which is the bilateral contracting.

MR. MEAD: I forgot who made this comment, but maybe it was Mr. Stoddard. At any rate, but in the long term, it doesn't matter what we estimate CONE to be. In the long run, we're going to see costs equal -- prices equal to CONE.

And that what's at issue is how much do we buy at CONE? Does anybody disagree with that notion?

MR. HAUSMAN: I disagree very strongly with that notion.

MR. MEAD: Why is that?

MR. HAUSMAN: Because that is based on a view of the world in which capacity can be smoothly and quickly added and taken away from the system, in order to equal Ray Pectone. But I don't think that describes the world that we live in.

I think that investments are lumpy in power plants, and I think that again, as I keep harping on, the impediments to investment are structural, at least as much overwhelmingly so in PJM rather than financial.

So you simply cannot, if present price were CONE plus a dollar, you can't sit there and say "Oh great. I'm going to put up a power plant in response to that."

MR. MEAD: But you know, even if you concede that investments are lumpy and there's a long lead time, would you agree that over a sufficiently long period of time, the average price is going to be CONE and the issue is over the very long term, you know, what's the average capacity level relative to IMM?

MR. HAUSMAN: I do not believe that, and the reason is that most of the entities who would be able to invest in a power plant in PJM or any of these markets, that's another point that I raised in my document here, which I'm sorry I need to make some copies so I can pass them out to everybody. As I say, there's some out in the hall.

But those entities are not just looking at that particular investment in order to make a decision as to whether to build or not. They're looking at their portfolio of assets.

If this is a company which already owns baseload assets in the area, they're going to make a whole lot more money by having the market be in shortage under RPM than by having it be in surplus.

So they're not just saying here's CONE, here's a plant. Even if the market were totally smooth, not lumpy, and there were no obstacles to their investing -- but I suppose there would be have to be two other single plant entities coming in -- the incentives just aren't as they're represented, either in the model or on the underlying theory of RPM.

MR. O'NEILL: Are you making a case for barriers to entry for small generators?

MR. HAUSMAN: I'm saying that unless each investor were a single one-off player that was just looking at building this one plant and didn't own anything else in the market, that the incentives that are being considered in this analysis, and the model that was used for this analysis, are inconsistent with the incentive of those investors, that they would in fact be looking at maximizing the profitability of their portfolio of assets, and they would say "Hey, high capacity price. I also own a coal plant" --

MR. O'NEILL: But there are entities who don't own a 500 megawatt coal plant.

MR. HAUSMAN: Well, and they face even higher structural obstacles to investing. Those entities, in many cases, are unlikely --

MR. O'NEILL: So the CONE price is too low for them to enter?

MR. HAUSMAN: I don't know if there's any price that would be high enough.

MR. O'NEILL: So you're making an argument that says that entry is a significant barrier here?

MR. HAUSMAN: I think that there are significant barriers to entry, yes.

MR. O'NEILL: And the only people that can enter are the people with a large portfolios to start with?

MR. HAUSMAN: I think they have a significant advantage in terms of control of sites, control of transmission access, fuel supplies, yes.

MR. ANDREW OTT: Let me ask you. I think if you look at the reality of, you know, people investing, in other words, look at the plants that actually have come on line, I mean there have been a fair number of plants that have come on line that weren't, you know, entities who have owned huge amounts of other assets.

I mean, essentially it's one of the most successful, you know, the most needed, if you will, plants in southern Delaware, the southern Delmarva peninsula was really not associated with a large portfolio. That was sort of a small entity putting in some papers.

So I'm not sure that the reality of what we're seeing is consistent with that. I think that -- and in

fact, putting in peaking plants which will cover this capacity, I'm not sure of the barrier. I mean neither the time barrier to entry nor the barrier to sites is as, maybe as immense as you're saying.
I'm not sure we're seeing that.

MR. HAUSMAN: You know, it may be that there are some areas in PJM where those barriers are not as significant as are the consumers representatives have been concerned that they are.

But among the how many local areas do we intend to eventually have in PJM, there's no doubt in my mind that there will be a significant number of them, where it is virtually impossible for independent generators, or maybe anyone, to build peaking plants.

Perhaps only transmission solutions would work, and those are completely absent from this whole construct and from the analysis underlying it.

MS. COCHRANE: Mr. Wallach has his card up.

MR. WALLACH: Yes. Just to follow up on that, you know, notwithstanding Dave's admonition that in the long run we're all dead, in the long run, I think yes, it does make a difference where you set that curve, and what you assume is the cost of new entry, to the extent that you're basing a curve or having a curve that's pegged to the cost of new entry.

One is, as you put it Dave, it defines, regardless of what is actually bid in, it defines how much capacity is bought at the actual cost of new entry, to the extent that new entry is setting the price.

We shouldn't ignore that. That can be a significant cost. Yet capacity, reliability value to having a capacity above your predetermined IRM. But that doesn't mean that you're -- that you're paying what it's worth.

In fact you're paying significantly more than that extra capacity is worth, and that gets back to our, you know, value of lost load issues that we talked about earlier this morning.

Secondly, you know, we should not forget about the fact that there will be times, because of lumpiness and other issues, that there won't be sufficient capacity, either existing or new entry, to have a supply curve that crosses, that clears on the demand curve.

You may fall short of the curve. Not necessarily falling short of IRM, but it may be that you've reached the end of your supply curve, and you haven't crossed the demand curve.

What happens then is that to clear the auction, you draw a vertical line from the end of the supply curve up to the demand curve, and that's your price, and that's the price you pay for all that capacity that's cleared.

That makes a big difference depending on, you know, what you're assuming for the cost of new entry.

MR. O'NEILL: But isn't that worse for the vertical demand curve?

MR. WALLACH: Isn't that worse for the -- no.

MR. O'NEILL: No?

MR. WALLACH: Because the vertical demand curve -- well, if you're in excess, the vertical demand curve will clear at the marginal supply offer. The price is always -- as long as you're in excess, the price is set at whatever's out there at the margin when you hit IRM. So in that sense, no, it's not worse.

MR. O'NEILL: But lumpiness is going to say that occasionally you're going to be on the left side of the vertical demand curve?

MR. WALLACH: Correct, and in that case, in today's structure, what you do -- what happens is you incur the penalty of --

MR. O'NEILL: A very stiff penalty and a penalty higher than you --

MR. WALLACH: Well actually, depending on what the system, the state of the system, today it's the cost of new entry. Now, you know, generators might argue well, there's some missing money there, because you know, on average --

MR. O'NEILL: Well, but just comparing the vertical demand curve with the one that has a little bit of slope, you'll be paying less under the one with slope, right?

MR. WALLACH: You'll be paying -- yes, and you could have, you know, you could have --

MR. O'NEILL: In fact, as I talked about in the statement that I prepared for this tech conference today, you can have a hybrid, which is a vertical curve with slope for quantities below IRM or IRM plus one.

You don't actually have to have something that's vertical and horizontal at the penalty. You can have something that's vertical and slopes up in the shortage.

In fact, you know, using Dr. Hobbs' model, using Ben's model, you can show that because of the forward procurement, because of that stability that I talked about earlier this morning with having new entry participate, you can have a curve, a hybrid curve like that and still get the same, you know, comparable long-term results that you get with PJM's preferred curve.

MR. CHOUEIKI: I just wanted -- I've been waiting to say something, but I wanted to hear the discussion about the cost of generation.

If I might oblige just for a second here, the question posed was, in our opinion, very limited in scope because RPM supposedly is a process to encourage investment, period, and to maintain -- the objective that were discussed earlier was reliability, IRM, or IRM plus one or whatever the decision is made.

And then least cost to consumers. Well, least cost to consumers is not always building peaker generation. It could be a transmission, it could be a demand resource, it could be anything.

So why are we always discussing cost of entry or these curves based on a cost of entry over generation solution, when it could be going from load eight zone LDA-X to LDA-Y, instead of building LDA-Y two generators that are peakers, it could be you have a transmission solution from Y that would be a lot cheaper for consumers.

So I just wanted to make that statement, you know, just because it didn't fit anywhere in the discussion earlier.

MR. ANDREW OTT: Or you could put an SVC in.

MR. CHOUEIKI: Yes. It could be different options. The focus is always on RPM, and RPM supposedly is a lot more general in maintaining a good reliability, least cost to consumers.

So the only discussion I hear is a demand curve that is only tied to a generation solution of CONE and twice CONE and one and a half CONE and whatever it might be. Then there's no other discussions about how FERC ordered PJM to tie transmission.

They agreed about demand response that we need to tie it to. I don't see that in the simulation model. I don't see that in analysis that ties the whole thing to cost to consumers at the end of the day. Those three are integrated.

When you design an electric grid generation, sometimes you build transmission and not build generation. I mean this is a known fact to solve a problem.

MR. ANDREW OTT: I mean I think you're absolutely right. They are integrated, and I think the RPM provides for the ability for the transmission demand response and generation solutions to be offered and integrated in the actual residual auction.

But I think what we're talking about here, one of the items we discuss in the industry, industry-wide, is we haven't seen the investment in demand response. In other words, there hasn't been the metering put in, at least people I talk to, there's some issues about expense, etcetera. But I think we're setting --

MR. CHOUEIKI: Okay. Go ahead.

MR. ANDREW OTT: We're setting a reference a reference price that essentially says this is the backstop cost.

In other words, if you don't do the demand response, if you don't put in the transmission that can move from an excess area into a short area, this is what the cost will be. This is the cost to do the job, you know, sort of the --

If you want ultimate reliability with, you know, with the 100 percent load level, meaning you don't want to curtail, here's what it would be.

If you have another solution, which is demand response, that will come into the auction, and you'll never even see that part of the demand curve, because essentially the demand response will come in and cut it off.

But the only way that's going to happen, just like we see in the energy market, is if the price gets to the point where the consumer takes action. What this model has to do is allow the consumer to take action with a load bearing entry, and it does.

MR. CHOUEIKI: Okay. So --

MR. MEAD: Are you raising the question that the cost of new entry, which is one of the parameters in setting the demand curve, should be based not on the cost of a peaker, but rather on the cost of transmission?

MR. CHOUEIKI: Could be. Actually --

MR. MEAD: Conceptually, why is that the right thing to do?

MR. CHOUEIKI: Okay. Actually, what I want is right now everything is tied to only generation peaker. Okay, that is AEP right now has 350 megawatts in Ohio of interruptible load.

They have, they control it. They can shut it down for a hundred and -- I don't know, 166 hours a year. So that's two percent of AEP load right there.

So why isn't that included somehow in the simulation model, for example? We're estimating cost to consumers. Well, cost to consumers, you know, is not only generation. It could be a lot cheaper if we had demand load responses.

Or if we have a transmission solution, how does it -- how do you include that in the model? There has to be a lot more discussion. How do you include a transmission line or a transmission upgrade from Load Zone A to Load Zone B?

I haven't thought about that, but they need to be included. Either we do separate, I don't know if you can do separate options, but you need to put them all on a equal field, you know.

They're competing against each other options. You're solving a problem. A long-term solution to a probably generally includes transmission. Those band-aids of peakers, that just doesn't solve the problem. It might solve the problem for a year or two, but it's --

I don't see right now in the analyses of the simulation model, or of PJM's discussion, with the exception that they mention now -- at least now we have an affidavit that says you make recommendations of how you compensate a transmission solution between two zones in the latest affidavit filed in the paper hearing.

I don't see that in the discussion how the impact of RPM is on consumers, if you include all these three together. I mean you're estimating costs.

We're defending RPM because of these costs to consumers. We're saying a lower demand curve or a low downward sloping demand curve is better for consumers, because we have this linear line that does better than a vertical line. But we're only looking at generation.

MR. ANDREW OTT: I'd like to follow up on a comment that Mr. Stoddard made in his comments, and I think a little bit here as well, that I am also impressed with the difference in estimates of the cost of new entry, and we'll come up with some number.

But he raised an issue in his comments that maybe we can't do it now, but in the near future maybe we should rely on estimates of CONE, not based on engineering estimates but rather based on the results that we got from previous auctions.

What do other people think about that? What are the advantages and disadvantages of in the future basing CONE on the clearing price or some weighted average of clearing prices in previous auctions?

MR. STODDARD: I mean essentially I think, you know, again as I mention part of the RPM construct is to actually have these reviews over time, and certainly having that review consider obviously, you know, with appropriate parameters, it can't be the clearing price. It has to be the clearing price in areas where you had new entry.

You know, in other words, where you had, you know, generation that actually came in and built. But that could be -- those bids are cleared offers that came in, could actually be a reference point as we get experience.

Certainly, you know, adapting the model, you know, having these three-year performance analysis to do that, could certainly be part of it, and it may in fact be a sound way to have continuing confidence that the numbers are right.

But obviously, that would not be the average clearing price. It would be the clearing price for the marginal bid that was accepted from new entry, as opposed to just the general clearing price.

MR. STODDARD: And that is what I intended to say.

MR. O'NEILL: Can I ask a question? What if the CONE is too low? What are the consequences? Let's say it's below the cost of entry.

MR. ANDREW OTT: Nobody will show up.

MR. O'NEILL: And nobody shows up and we have blackouts, right?

MR. ANDREW OTT: Well, we manage curtailment. Well yes, and again, you'd see this coming. You'd essentially see an area where you were short with no new entry. You have it the first year, the second year, the third year.

You'd see it coming. Again, the process has backstop. I actually can say if that should happen, we have an escalating urgency in performing new analyses to determine what went wrong.

MR. O'NEILL: And you raise the price of CONE?

MR. ANDREW OTT: Well, yes. Well, I raise the price of the CONE. I say, you know, it may not be the CONE. It may be a barrier to entry, whatever. We look at the issue.

But I think, I mean long prior to going short in average, we would see this coming, and even after one year of such shortage, where we would have no entry and be short, we would, you know, I'd be obligated under the proposal to do an analysis and file whatever potential remedies with the

Commission and talk to the stakeholders about it.

So I think going into that is just taking into account this possibility.

MR. O'NEILL: So in combining this with Dave's question, what you're doing, if your CONE is too low, you go into -- you look at the results and say my CONE is too low. So I raise the CONE, and I think what Dave was saying is if your CONE is too high, maybe you lower your CONE.

MR. ANDREW OTT: And I would agree. I mean if in fact you see that the actual results come in, using those results over time is actually prudent, and certainly the model -- it would be a good adaptation to have that type of ongoing analysis, and I think it already does exist in the market.

MR. HAUSMAN: I don't have Andy's job, so I can't make this decision of what you do. But I'm glad to hear that PJM would have resources at hand and procedures at hand to make sure that we don't fall into a shortage situation.

It sure sounds to me that with the exception of them going and doubling CONE and hoping, you know, crossing your fingers and hoping that that worked, that what PJM could do is look at more cost-effective solutions like putting out an RFP for generation where it's needed, bringing transmission solutions on line, putting out extra incentives for demand response.

It seems to me that there are lots of things that could be done in the situation where it looked like there was inadequate capacity, that would be not --

(Simultaneous discussion.)

MR. MEAD: --an RFP for generation where it's needed?

MR. HAUSMAN: No, it's not. It is absolutely not, and the reason is that if I put out an RFP for generation where it's needed, I will pay the entity that builds the generation that I need.

But under RPM, I would pay them and then I'll pay the same amount of money to every other entity in PJM or in the area, including all the baseload, coal and nuclear plants that have amortized and paid down and making tons of money in the energy market, because I don't think it's at all right having an RFP.

That's much more expensive, hundreds of times more expensive for the same goods without the guarantee of performance. So if I'm doing an RFP, somebody has to actually build something for me to pay them.

But under RPM, they don't have to build anything. In fact, the less they build, the more I pay them. That's the way I see it.

MR. MEAD: I thought the import of a lot of your comments was that it didn't matter how much you paid them to do it. There were impediments that were going to prevent generation entry. So I mean how does a contract solve that problem any better than an auction?

MR. HAUSMAN: Well, I think that there are a lot of resources that PJM and the states haven't had. I mean if they really need to, there's eminent domain and there's building transmission solutions.

So I think that there are a lot of resources in hand to address these problems, and they do come at a cost. But at a much, much lower cost and with, as I say, a guarantee that you'll actually solve the problem.

MR. MEAD: So how does eminent domain solve this problem?

MR. HAUSMAN: I probably shouldn't have raised it, because I'm not an expert at all.

MR. GOLDBERG: I think I'll jump in for a minute to respond to the issue about state demand response programs. How are they included in RPM? Do they have to bid in or do they reduce the capacity?

MR. ANDREW OTT: Well essentially, in RPM there's two ways essentially demand response comes in to participate in the RPM, at least two.

The first is of course they can offer, in the forward residual -- in other words, the base residual option, which is done, you know, under the proposal four years out, is essentially again a residual option.

Obviously people can do their bilaterals, you know, bring in their generation. They can also put in their demand response offer, and of course schedule it into the market.

So they may say, you know, of my 100 megawatts load, 20 other can be curtailable, which will essentially lower their capacity requirement, and they can offer that in, which would substitute for a resource.

So what you'll actually see, what the auction clearing mechanism would see is a net decrease in the demand, or the demand-supply balance would actually drop down the demand in supply curve cost. That's the first way. So that's done on a forward basis.

There's also the more -- then that would tend to be stuff that would, could invest. You know, you'd see -- new building controls could be put in, so people could make a business case.

They could actually say "Okay, now I can actually see forward. I'll get revenue if I put in infrastructure to create demand response."

So it actually creates, you know, for the first time in our market anyway, a longer-term business model for demand response.

The second way is of course more the traditional, where they have what we call today is ALM, which are these demand response programs. The same thing exists in the RPM model. It's called an ILR. We had to change the acronym just, you know, to keep current.

But the ILR will come in. They actually specify right just prior to the delivery year. That has the effect of reducing the entity's, the load-serving entity's capacity obligation, so they end up paying less, okay.

So either way, they can do it either as a shorter-term deal or they do the long-term commitment. I think, you know, again, as we talk about these simulations, if you look at the effect of these things in demand response, okay.

It's essentially a net change. So it looks like you have more generation relative to load. So in simulations, demand response would actually just look like more generation.

So I think implicitly it is in there, and you can see the effects of it, because you can see well, what would happen if you had more, what would happen if you had less. So I think those kinds of things can certainly -- the dynamic of it is certainly in the RPM itself.

I think if you had a lot of demand response come in, obviously that would lower the price of capacity tremendously. So I think what these simulations are doing is actually showing the comparative or the relative performance of these curves to a certain set of assumptions.

Obviously, if you had more demand response, you'd just lower all of them. I'll let Ben speak to that.

MS. COCHRANE: We've been going solid for two hours, and we had a break scheduled for right now. So but why don't I -- but you guys both had your cards up. Why don't I let you guys hear what you want to say.

We'll take a break, and then we'll come back and finish the discussion, since it seems to be a little bit more discussion on this topic before we go on to the next one, if that's okay. But I think people need a break.

MR. PICARDI: All right, thank you. My point was kind of to remind everybody a little bit about what the purpose of -- part of the purpose of CONE is, because we're doing this curve.

Part of the purpose that -- this discussion is all focused on new entry, but part of the purpose is also, and according to the FERC order, to make sure we're setting the right price to retain existing generators, which is one of the problems we're facing right now and the main reason maybe that brought us here.

So while we have the dialogue about what the cost of new entry is, we need to remember that wherever we place that point in the curve, it's going to affect what happens to the supply that's already on the system, and we need to remember that when we analyze it.

MR. STODDARD: I want to echo that. Ezra has raised a couple of times now a point that is actually settled. The Commission correctly has concluded in a series of orders that it's wrong policy to pay different people different amounts, for providing what amounts to the same product.

I don't think we need to revisit that. Economically, that's the right decision and the Commission has made it.

I do want to go back to a point about well what happens if we miss? I think the thing to realize is we've set up this RPM auction, the base residual auction, the one that happens four and a half years in advance.

It's really the best opportunity for PJM consumers to buy generation at the lowest possible cost. You've got the greatest planning period; you've got the most range of options. That's the time you should be trying to focus the purchasing activity.

If there's a clear expectation that was CONE, and that there's going to be escalating CONEs over a series of auctions, that's going to encourage a couple of strange competitive dynamics.

One is that people with projects, instead of bidding them in up front, sit back and say "Well, I think the CONE will be higher later. Why would I be the sucker and take the low price now, when I can hold out and build my project at some higher price later on?"

So as important as it is that we have thought about the issue well, what do we do if no one shows up, the most important thing we should do is try to get the right estimate up front, that will get the generation we need at the time when it is most apt for consumers and developers to be buying it.

MR. O'NEILL: Bob, does your argument assume market power and entry? That's what it sounds like.

MR. STODDARD: No, no. It's merely a strategic behavior, saying --

MR. O'NEILL: The strategic behavior requires market power.

MR. STODDARD: I don't think so in this case, Dick. I think it's simply saying if I want to sell now or I can sell later, when would I prefer?

MR. O'NEILL: If you have competitive entry, as soon as the price gets to where you're making money, you enter. The only way you can strategically withhold is if there's some kind of market power, at least as far as I can tell.

MR. STODDARD: I'll think about that.

MR. O'NEILL: I'd like to speak to that after the break.

MS. COCHRANE: Yes. While we're all thinking about that, why don't we come back -- at 11:20, 11:25 start to come back.

(Whereupon, a short recess was taken.)

MS. COCHRANE: Can we please get started? Let's put his card up and he's not here.

MR. STODDARD: I'd like to clean up that last comment.

MS. COCHRANE: Oh, do you want to clean up your last comment?

MR. STODDARD: No. Upon further reflection, I think that Dick is exactly right, that the -- for the record, Dick is exactly right, that what will happen, of course, is people -- in this market design, people will reflect their true cost of new entry in their bids, and the risk, of course, is that if we set a curve where those either can't clear or we buy too little quantity.

I mean fundamentally, this demand curve is, as Dave correctly pointed out, not telling us what price we're going to be paying in the long run.

My view is that it's going to tell us how much we're going to be buying, which is why calibrating it, do we buy what we've decided we need to buy, whatever number that is, at the price of cost of new entry is critical.

But it's not as subject to the competitive concerns that I raised earlier.

MS. COCHRANE: Okay. Seth, you had your card up before the break?

MR. PARKER: Thank you. During the last part of the discussion before the break, there were a number of subjects that came up that I wanted to comment on briefly.

One is that this concept of the missing money is real, and I think should not be ignored or minimized. Secondly, there are -- there is going to be some compensation to consumers if new capacity in fact is developed in the form of more competition and hence lower prices in the energy market.

In addition, I wanted to emphasize that just because the demand curve is based on the cost of new entry for a peaker, there's nothing excluding transmission and demand response.

I mean, time will tell and market solutions will be revealed, and just because it's set on one particular technology and type of plant, it's not, in my mind, a real problem.

Very quickly, the backstop solutions for capacity in case there is a persistent shortage is nice, but it's not a market solution. It smacks of RMR. If we get the demand curve right, and we set prices that are not too low and not too high, but enough to encourage generation where needed in those locations, hopefully we'll never get there.

Then lastly, I'd like to go back to the question that got this whole part of the panel rolling, which is what should the right cost be? Again, I'd like to just quickly emphasize that the reactive power filing data, I think, is good, solid, real numbers that might require adjustment.

Ray and I were talking about Sheboygan Falls. I will very much -- I'm very much interested in digging into those numbers, and hope to provide some comment back to staff in the post-technical conference comments.

MR. MEAD: Yes, Jonathan.

MR. WALLACH: Just, one theory, given that we've now had a break and I'm trying to remember what it is I wanted to respond to.

But something that Bob just said, in that -- and Dick's question about, you know, is there, you know, are we talking about market power in the market for new entry.

I think the point to be made is while there may be competition in the market for new entry, maybe not, depending on how small an area we're talking about, the fact is that the way RPM is designed, in order to be able to -- for a new project to participate in an auction, they'd have to be in the queue, and they'd have to pass certain thresholds.

Which means that you've basically removed the uncertainty associated with new entry, and the ability or the power of that uncertainty to mitigate the ability for someone, for an entity to exercise market power in that auction.

In other words, if I know what's in the queue and if I know who's eligible, which new projects are eligible to participate in an auction four years from now, that means if I'm an owner of existing resources, a portfolio of existing resources, and I know what the obligation is, I know, you know, what the parameters of the curve are, I know --

I have, you know, full and certain knowledge about whether I am pivotal, and whether I have the capability to economically withhold for the purposes of driving up the clearing price of that auction to higher levels than what you would have absent that exercise of market power.

I think that's, you know. So you could have a perfectly competitive market for new entry, yet still have an issue with the ability of someone to exercise market power in those auctions.

MR. MEAD: Before we leave this topic generally, there's two other questions I want to ask.

One is just to make sure that everybody's had a chance to speak on a question I asked earlier, and that was with respect to Bob's idea that not in the first auction but a few years down the road, should we abandon engineering estimates of CONE and use some market estimate of the clearing price as our benchmark for CONE.

Andy answered, replied. But I just want to make sure if anybody else had any views on that.

MR. WALLACH: Maybe.

(Laughter.)

MR. WALLACH: It's not formulaic, and it's not automatic. Just for example, what I was just speaking to, the issue of market power.

If you have a problem with market power in a small LDA, then you don't want to be relying on the clearing price or the fact that you cleared short, to set your CONE for the next round, that you're just headed -- you know, you're not solving the problem. You're enabling the exercise of market power in that respect.

MR. PICARDI: I guess I had two comments. I think you've always got to go back to the situation we're in now, and I would assume that especially for around the IRM, the incentive to withhold would be much greater than if we're in a situation where we have a slope demand curve, and that was what led us to a lot of this discussion to begin with. So let's not forget that.

The second point is I would add, as I was talking to Dick, some anecdotal evidence of the process of using some type of real auction to set capacity values for other people in the market, or in this case it would be replace the CONE process.

We saw that up in Ontario, from the point of view where the government ran an auction and solicited bids from a bunch of developers to build new gas-fired generation in the province.

They then said "Okay, we've got to treat some of the existing merchants fairly, because we've kind of changed the market here on them." What they did there was take the results of that and say "Okay, well generally we'll apply those to the existing folks for a certain term."

The one observation I would say about that process, and again this is having witnessed it and it having analogy to this situation, was that several of the folks that bid into that kind of low-balled their bids and did the opposite of what one might expect, for the sole purpose of getting their foot in the door figuring they could negotiate it up.

This left, again, one of my main issues, what happened to the existing guys with maybe a less than optimal price? So that would be on the reverse side of the analysis, which you might have to think about.

MR. HAUSMAN: I'm sorry. I just have to respond to one point Mr. Picardi made at the beginning there, which is that the current -- you're comparing a slope demand curve, which is a four-year ahead, centrally administered auction with a set price, to a vertical curve under those same circumstances.

No one in this room is advocating for a four year ahead centrally administered set price vertical curve auction.

MR. PARKER: Conceptually, I think the notion of refining the cost of new entry over time as prices are revealed make sense. Of course, the details are going to be important. But it shouldn't overshadow the need to get the price initially as accurate as possible.

MR. GOLDBERG: Dave, I just wanted to point out that the Commission has already determined that at least one aspect of this market will have a downward sloping demand curve.

We're not debating here whether or not we should go to a vertical demand curve or not. That was decided by the Commission order. The question here is just what the slope of that demand curve could be.

The Commission pointed out that that would be one option, and the other option would be to opt out. And they said people would have that right. So that's for tomorrow's discussion.

But today, we need to really focus on what the slope of the demand curve is, but it must be sloped, at least for the purposes of our trying to fulfill what the Commission asked us to do.

MR. MEAD: I have one more question, and then Tatyana has a question. This is more of a detailed question, but on the issue of how do you estimate CONE, and this is following up on a comment I think Mr. Wallach made in his comments.

As I understand it, the estimate that Mr. Pasteris has made is one that's based on levelization. As I understand the principle, it is if we have, as I recall, it was $466 per kilowatt, if a new generator got $466 per kilowatt every year for 20 years, he'd recover his costs.

But the auction contemplates that over time, there will be adjustments, presumably to reflect inflation. So that a new entrant in the first year of the auction is likely to expect not $466 but something that goes up. So that perhaps this method of levelization doesn't-- overshoots, ignoring all the other issues, but for this particular issue that this method for levelization overstates what the real cost of new entry is.

Did I state that correctly? And if so-- MR.

WALLACH: Yes, but the numbers you used are, I think it's $72,207 per megawatt year is the fixed before any net revenue offset is the number to use, versus the escalating, the starting year escalating value, which was somewhere around 61, 62 thousand, around that number.

MR. MEAD: Forgive my specific numbers. But if you could comment on the methodological idea.

MR. PASTERIS: Well, it's kind of viewed as being essentially equal from a net present value basis, that if you started the net, the revenue requirements at say $62,000 per megawatt year and escalated it at two and a half percent over the 20-year period, or then determine -- and that's based on the financing assumptions that established a 12 percent rate of return based on 50 percent equity.

Now what you do is take the model and say okay, what levelized equal payment over the 20-year period would provide to you the same net present value of revenues and the same return. That was $72,207.

MR. MEAD: Why is that the right number to use for this auction?

MR. PASTERIS: I'd like to defer to Andy, then, for that answer.

MR. ANDREW OTT: I think it's good to remember here, obviously as this -- as the market marches forward in time, the fact that the CONE was, you know, at the 72,000 to start with, that's not a guarantee to that generator that they're going to receive that payment over a 20-year cycle.

In other words, it's not like a rate of return type guarantee, where obviously if that number adjusts later. You know, in other words the CONE in the fifth year in is different because the fifth year in has -- we've inflated, so we calculated a different number.

But that original generator who jumped in doesn't have any guarantee. There's no 20-year guarantee that he's going to clear in the auction or receive, you know, that revenue for a period of 20 years. He's essentially competing once he gets in, once he enters, and he is existing.

Absent some, you know, adjustments for his expectations, he's not necessarily being guaranteed that 72 for the whole period.

So the reason we felt that it was necessary to, as time goes on, to reset that CONE based on the cost of entry now, as opposed to what it was five years ago and keep it the same for 20 years is obviously things change over time.

Since we aren't providing 20 years guarantees to folks, we thought it was the best -- the best approach was to have that CONE adjust as time goes on, but also see that levelized payment in the year.

I think the real nugget there is I don't think there's a guarantee of over-recovery here.

MR. MEAD: Of course, I mean in a market setting, you know, there's no guarantee of anything and you expect supply to vary relative to IRM and all that.

But I thought the objective was or maybe the thought was that on average, investors could expect to receive CONE over the life of their asset. The way this thing is structured, the average level of CONE over the 20-year life would be higher than this $72,000 number. Jonathan?

MR. WALLACH: I think that's exactly the point. I mean you're trying to set a value for getting, you know, the appropriate amount and efficient amount of investment over the long run.

And at that point on the curve where if you do clear at IRM plus one or whatever the inflection point is, that that would provide a price which covers -- which provides for recovery of a new investment, as you've estimated the cost of that new investment to be.

The problem with using the levelization number as opposed to the first year number, what some people would call the real levelized number, is that, as you discussed, if in the next year you don't make any adjustment, so you're still at $72 in the next year, then somebody --

Then your new entry in that year, whose costs are now are likely to be a year's worth of inflation more than the guy who came in in Year 1, if you don't adjust the CONE, then they're guaranteed to under-recover if you're clearing at the inflection point.

So you've got a problem where the guy coming in in Year 2 is not making enough money, based on that $72, and you've got the problem of the guy who came in in Year 1, who makes enough money at $72.

If in Year 2 you now raise it for the purposes of, you know, providing sufficient revenues for someone who's coming in in Year 2, then that person who came in Year 1 is now being paid too much money.

Let me just finish by saying that in New York and in New England, prior to the settlement, this wasn't even a question.

It was -- the CONE value was set using the first year or real levelized cost, understanding, you know, the economic theory behind it, which is that costs will rise with inflation over time, and that it's appropriate to use that real levelized number.

MR. STODDARD: Let me just add a side point on that. We have to remember this is also a net number. So at the same time that we may be increasing capital, the unit we've installed is becoming technologically obsolete over time, and is becoming, you know, less efficient even relative to its clean and new state.

So even though we continue to deduct the benchmark, the revenues from the benchmark generator, this unit won't be behaving consistently worse than the benchmark generator in every year except Year 1.

So there is a compensating downside that we have not built into this market.

MR. STODDARD: Ben?

MR. HOBBS: And not only that, there's expertise around the table who can answer this question. But how does the capital cost in real terms of a turbine today compare to 20 years ago?

Have they been going down in real terms or up in real terms? I actually don't know the answer. I didn't follow the lawyer's advice of never asking a question you don't know the answer to. But I think that's important here.

There is that uncertainty. So somebody coming in now may be facing a situation where not only did they not get the gross margins in the energy market, but also capacity prices may be going down in the future because of technologic progress. So this is not a world of certainty.

MS. DEBORAH OTT: Can I just ask a quick, clarifying question, I think? So if I'm a potential new entrant, and I participate in the RPM auction and I'm selected, I'm guaranteed a price to be paid four years from now. I'm not yet built.

So the following year, another auction is held. I bid my yet to be final project again in, and I -- and let's assume I'm selected again, I now have a different price that I will be guaranteed for a second year, and that's the process that goes on? Okay.

MR. ANDREW OTT: That's right. Yes, that's correct, and again, we should point out that when we set this CONE value, that essentially sets the demand curve references.

Obviously, it doesn't set what folks can offer. So they would offer, again, whether it be higher or lower than that, depending on whether they have other contracts, etcetera.

But the key there is that yes, they would offer -- obviously they would be guaranteed the clearing price if their offer were higher, because it's a marginal price market. But yes, you could see fluctuation in what they get paid as time goes forth, right.

MS. DEBORAH OTT: And then the CONE itself would be adjusted at some point during this four-year period; that's correct?

MR. ANDREW OTT: Like the CONE could get adjusted

-- obviously, it's not going to adjust the past clearing prices, but for the going forward, you know, if something we find whatever it be, inflation or whatever, during that review period we discussed, which isn't, you know, no longer than three years we do a review and determine if we need to change it.

Again, I think -- I believe that calls for a report to the Commission. It more than likely does, as part of this process.

MS. DEBORAH OTT: And then during this initial period while my project is under construction, I am viewed as a new project?

MR. ANDREW OTT: Correct.

MS. KRAMSKAYA: I have another clarifying question, with regard to readjustment of CONE. That would happen in Year 3, which means prior to the actual delivery year. Would that change the demand curve in that lost residual auction?

MR. ANDREW OTT: But again, when we would change the reference, the CONE or any of these other values, it would be changed for the next base residual auction, which would be four years from the date we change it.

So we wouldn't be going back and changing results of auctions that had already occurred, and then cleared. In fact, you know, those auctions have already been done. The results were cleared.

We may have incremental auctions for those years, but that doesn't involve these reference points.

MS. KRAMSKAYA: I guess I meant the less incremental auction is, I guess, what is it four months before the delivery date?

MR. ANDREW OTT: Oh, the incremental auctions? No, it would not affect -- the changing of the CONE reference would not affect. It would be looking forward in time at the next delivery year to be run, not the -- that would be the intent.

I mean the incremental auctions, again, don't depend upon a demand curve, because there's supply and demand bidding to reshuffle their -- it's almost like a balancing-type auction. So there's no "demand curve" in there.

The demand actually in that case is folks trying to either sell or buy additional capacity to change their position in the year. So the only real auction that has the demand curve requirement is this base residual, which is the initial auction for the delivery year four years out.

MR. WALLACH: Actually, there is a demand curve in those auctions. It's a demand curve determined by market participants' offers or demand bids?

MR. ANDREW OTT: Right.

MS. COCHRANE: We're going to move on to the next topic at this point, which is "How should expected revenues from the NMG and ancillary services markets be estimated, and how should they be used to adjust the height of slope of the demand curve?"

MR. MEAD: And for that, I'd like to follow up on the comment that Mr. Stoddard made just at the end of this last discussion.

As I understand it, the estimate of energy and ancillary service revenues that PJM has made is based on the expected -- well, I guess it's an average of the previous six years. But of a benchmark unit that's random.

I guess the question I would ask is should we be looking at a brand new plant, or should we be looking at a middle age plant? That is, well, I mean if the idea is, you know, what kind of revenues can we expect, can a new entrant expect over its life?

Should we be deducting revenues from a brand new plant every year, or from sort of a plant of average heat rate and other operating characteristics? Who wants to answer?

MR. HAUSMAN: Well, we would prefer to see actual energy and ancillary service revenues deducted from capacity payment.

MR. MEAD: That's a very interesting point, and I wanted to discuss that a little later. But for a moment, can we focus on this issue?

MR. HAUSMAN: Okay, I'm sorry.

MR. MEAD: Whether it's, you know, actual or forecasted? Should it be based on a brand new plant or an average efficiency plant?

MR. PARKER: We wrestled with the same question in New York a couple of years ago, and determined that really when we talk about real world performance, you have to consider real world factors such as degradation in both output and heat rate, as well as different amounts of capacity during the different seasons, summer versus winter.

So my quick answer is if you are looking to, either on a forecasting basis or on a backcasting basis, try to really understand what a peaker would earn in net revenues, you have to consider those real world conditions.

There are kind of rules of thumb that indicate, you know, what in general those levels of degradation, both again in capacity and heat rate should be.

MR. WALLACH: While I agree that you want to incorporate real world conditions, there is one element, though, that you need to go into the realm of the theory, and that is in terms of -- we have to remember that we're setting net revenues for a new unit at -- in a system which is at IRM or IRM plus one, whatever your inflection point is.

We shouldn't be setting net revenues based on what a peaking plant would make in PJM's market last year, when there was, you know, large excess of capacity and prices were very low.

What we should be doing is looking at what would the net revenues be in a system at equilibrium, because we're setting the point on the curve for a system at equilibrium. That can get you a much higher number in terms of net revenues, than if you say, look back three years or six years or historical data for a system which is, you know, which has seen a lot of excess in the system.

MR. CHOUEIKI: I was going to mention, state the same thing. Actually, I think PJM has a proposal of six years look at historical, because that's -- you're covering basically lots of heights, different peaks. You're covering growth. You're covering changes in temperatures.

I mean basically, that's the best you've got, is to look at historical data, but not over one year, because one year could be an aberration to average behavior of load, but look at several years.

Maybe look at several years, where some of them--during those six years, hopefully you've gotten some peakers that came on during those six years, so you can look at their behavior over four years or five years.

But basically not look at one year or two years, and basically not try to forecast on your own.

MR. MEAD: Jonathan, how do you go about estimating what -- how would you implement your -- I mean I understand the notion that, you know, we're trying to set the cost of new entry at whatever our target is, IRM plus one or whatever.

How do you go about estimating what that revenue would have been if you -- you know, if it turns out you've got a different amount of capacities in this target?

MR. WALLACH: Well, there's a couple of different ways, none of which are entirely satisfactory. I mean you're getting into more art than science, but that's the nature of this business.

One way is what we attempted to do in New York, although it was rather contentious and it's not quite clear that we got to the place that we should have.

But at Levitan, Seth did forward forecasting of the system, and you could look to see what net revenues would be as the system tightens up in your modeling, and there's uncertainty and all sorts of other issues involved with using forecasting modeling.

But it can give you a sense of how things might change or how, you know, your net revenues might look as you get closer to an equilibrium point.

The other way of doing it is actually Ben did something like this for his simulation model, which is to try and fit a curve, and again, you know, there are a lot of issues with, you know, how you go about fitting a curve and I may not necessarily agree with the way Ben did it.

But the concept is that you look at the relationship between net revenues and experienced reserve margins, and you can fit a curve and say well, you know, this is what we've got it at, you know, when we had this much reserve, and this is what we got when, you know, this much reserves, and use that curve to estimate.

MR. MEAD: Bob?

MR. STODDARD: Let me try to parse what we've gotten, because I think there's a lot of concepts floating around.

One is do we return actuals or hypotheticals. Jonathan's been talking about hypotheticals that again opens up the world of modeling. Your question at the start was in any of these hypothetical or actual returns?

PJM has proposed an actual return, by the way. They proposed we take a look at what actually happened in the market during some period of time, and at some period in the future, return that. Now what I gather Ezra objects to here is that the lag between the time when we observe the payments and the time they're rebated to consumers.

But we are still talking about actuals. The modeling issue you raised, though --

MR. MEAD: Can I just stop you? I thought what was happening was that there is some estimate of CONE. There's some estimate, ex-ante estimate of energy and ancillary service revenues.

We'll subtract those revenues from the cost, and we're going to have a demand curve.

MR. STODDARD: But those estimates are linked directly to actual, then another way to think about that is that the money that was actually paid is actually rebated, but with a long lag going forward.

Whereas what Jonathan was describing is actually a different model of a purely hypothetical system, that of course in any one year PJM will never be, or why did it make that deduction?

Neither really goes to your question, which is should we be modeling either the revenues, hypothetical revenues, or the actual revenues against a clean and new or a realistic unit?

Again, I think it is more apt to be modeling a more realistic unit operation throughout all of this.

As I said in my comment, I think one of the things we ought to be doing is make sure that whatever dispatch model we are imputing to calculate this, needs to go and be benchmarked against actual performance.

I'm always concerned that computer models are never as accurate as reality, and we have a lot of peakers in the system. We should be able to look at actual peaker performance, and make sure that the models are performing realistically and giving a realistic deduction.

MR. WALLACH: It's all hypotheticals, to a certain extent. The point I'm trying to make is that we're trying to set a point on the curve, one point, the point at IRM plus one, and what we're saying is that point should be set at cost, capital cost for new entry less net revenues.

Net revenues at that point on the curve, IRM plus one, should reflect what your net revenues should be at IRM plus one. It shouldn't reflect that net revenues were achieved over the last three years, for a system that was at IRM plus ten.

That would understate the net revenues for that point on the curve at IRM plus one. It may in fact be that the way you draw the curve, if you clear the curve at IRM plus ten, that that number on the curve would reflect net revenues to be expected for a system at IRM plus ten. But that's a different issue.

The point that needs to be made is when you're constructing the curve, which is what you're doing; you're constructing a curve. The point that you're picking for the

IRM plus one quantity should reflect the net revenues for a new peaking unit or new peaking unit average over its life, with all the degradation.

The net revenues that that new unit would receive, with a system that has capacity, actual reserves of IRM plus one percent.

MR. MEAD: Ray.

MR. PASTERIS: First, I'd like to make the comment that most generators or energy developers would, though the CONE is based on the GE Frame 7 FA unit, that there are other competing engines out there, and they would look at what cost they could built a similar CONE unit, maybe using that as the base engine, if it has a better heat rate.

But possibly maybe the cost of it would be a little bit higher. They would then say well, based on the net revenues that they would obtain at a better heat rate, they would still go in with that. It wouldn't stop them from doing that.

I would caution against any type of analysis of net revenues that represents some type of degradation in the heat rate, because it might take away incentives for folks to keep their engines as new and clean as they possibly can.

MR. MEAD: Why is that?

MR. PASTERIS: Pardon me?

MR. MEAD: I don't understand the assumption.

MR. PASTERIS: If you say that the net revenue ought to be based on an engine at the end of its life, then where would the --

MR. PARKER: Just jump in and then I'll turn it right back to you, Ray. When we talk about degradation, again what we did in New York was assume that there's a maintenance cycle, and some of it's driven by economics; some of it's driven by manufacturers' recommendations.

It degrades over time and at some point it becomes cost-effective to rebuild the turbine section and replace hot gas path parts. You repeat this, what's traditionally called a saw tooth pattern over many, many years. By golly, you can kind of draw an average level of degradation.

So when we talk about average, we're not talking about the end point or the worst case, but just over say a 20-year time frame, about how it performs on a long-term average basis.

MR. MEAD: We're still talking about a benchmark unit that's used -- that's producing some revenue that reduces the curve, and any individual generator that can beat the benchmark would presumably be able to profit.

MR. PASTERIS: Right, right.

MR. MEAD: I'm not sure that whether we pick a brand new unit or a middle-aged unit or you know, an old dog, that that would per se affect the incentives of generators to undertake maintenance or anything like that.

MR. ANDY OTT: I believe you're correct. It shouldn't affect the incentives for people to keep their engines as clean as possible, and restore them, as best they could, to the conditions, based on the maintenance schedules that they should undertake.

MR. MEAD: Seth, you had something to say.

MR. PARKER: On another matter, or getting back to this question of historical data versus forecast net energy revenue data, I'm not sure that either one is correct.

If you were to look at historical data and try to adjust that for a market that's at some kind of IRM equilibrium, the trouble is that (a) that would be difficult to do, and (b) there are other parameters that is just very difficult, if not impossible.

What if it's a cool summer or a hot summer, regardless of whether you're at IRM. So it's fraught with difficulties. I think what's really important is to have knowledge in advance, to whichever way you approach it, in advance of the auction.

Once you set a capacity price, that takes into account these net energy revenues, again whether it's done on an historical basis or a forecast basis, so that bidders have a certain price certainty. It facilitates the smooth and proper functioning of financial markets for the purpose of hedging.

I think the biggest mistake you could make would be to set a capacity price, and then after the fact, make adjustments that people don't know until after the fact. That would really tend to interfere with good market functioning.

MR. MEAD: Andy?

MR. ANDREW OTT: I just wanted to talk about using historic knowledge of locational prices to calculate the potential revenue, as opposed to using a hypothetical simulation.

I think using the historic LMPs, some range of years, obviously I agree it's not one year because you have anomalies; we picked six years because we think that would create the ability to model all the cycles, if you will. But to actually try to take that data then and try to look at various levels of capacity and try to adjust those prices. There are so many other factors: transmission constraints mitigation, these other factors that are also in there, that to actually go through and exercise to try to somehow adjust those prices based on total capacity when really, I think it's really the total energy balance that you're looking for is probably something that would introduce a lot of error and model uncertainty.

So I think it's probably some version of looking at the historic LMPs, comparing it back to the reference unit would probably be more practical to implement, if you will.

But I think all that aside, I again reference back to thinking about the reality of this. Okay, the reality of this says that for the first year of implementation of this, this CONE estimate and then the net revenue offset to get a net CONE is going to be an important item for the first year or so, or three years or whatever. But then as we gain experience, as we had discussed, there will exist for us then, you know, the net bids that people were putting in, which presumably would, if you assume competition, the new entrants that actually win would be the ones who say, I can bid a certain amount for capacity expecting, you know, to get some revenue, and then actually see their estimates, which gives us much more robust information as time goes on.

So I think the amount of importance of this then, you know, could diminish over time as the market gains experience because the actual net CONE could be the estimates of these bids.

MR. MEAD: Ezra.

MR. HOUSMAN: Well, let me see if I understand your question correctly because I'm not sure that we've been answering it.

The way I understand is that you're asking: If we look back over six years of experience to try and determine what our estimate of energy and ancillary services are, what unit do we look at?

Do we look at some existing unit?

Do we look at some demand response program?

Do we look at transmission?

Do we look at the most expensive unit on the system, or the most efficient unit?

Is that the question? Like how do you -- what do you use as the proxy for these energy and ancillary service views?

MR. MEAD: More or less. I mean, I presume the idea is that we're going to pick some technology and decide that this is the benchmark pure capital unit. If it's a Frame Seven, so be it, or if it turns out to be something else, then whatever.

But let's suppose for a moment we decide that Frame Seven Unit is the right unit. Should we look at the revenues that that unit would earn that's a brand new unit? Or that's sort of a mid-career unit? Or something else? And this abstracts from whether we deduct real revenues versus the estimates. I want to talk about that but a little bit later.

MS. HOUSMAN: and I guess my response to that is that it is an extremely hard and perhaps unsolvable problem. It's a sort of modeling exercise that people are required to do if they are considering for themselves, with their own money, investing in capacity in an energy market.

However, in order to use it for the purposes for which it is currently proposed, I would say that it's an unsolvable problem. So my proposal is, use the lowest cost base load coal unit and the energy and ancillary services revenues from that.

MR. STODDARD: And the capital costs associated with it.

MS. HOUSMAN: Exactly.

MR. STODDARD: So it would be zero.

MR. HOUSMAN: Zero.

MR. STODDARD: So no curve.

MR. HOUSMAN: No, I was a little tongue in cheek, but my point is, I hope you will accept, is that, you know, we don't know the answer to that problem and I don't think PJM really knows the answer to it either.

MS. KRAMSKAYA: I just wanted to ask another clarifying question. Are scarcity prices not included in these offsets?

MR. ANDREW OTT: They would be included. In other words, if you use the historic locational prices, PJM recently had implemented the scarcity pricing concept and so those would show up in the historic locational prices as time goes on so, yes they would, actually, in the proposal they would show up as additional revenues to that generator should it be located in the scarcity region because you would see those by locational prices.

MS. KRAMSKAYA: Then there are offsets, I think in the scarcity prices themselves to the RPM capacity payments, I think that's in the tariff.

MR. ANDREW OTT: I think I'm struggling with --

MR. WALLACH: I think you may be thinking about PMJ's proposal about how to set the offer caps under the market mitigation proposal.

MR. ANDREW OTT: Right, that's under mitigation.

MR. WALLACH: And in that case, yes, there is an offset for expected net revenues.

MR. ANDREW OTT: But that's under a mitigation scenario as opposed to in this CONE.

MR. GOLDBERG: I have one question. I probably should know the answer to this but, Andy you brought it up a number of times, you're going to be constantly making adjustments and making filings with FERC? Are you going to be making 205 filings to continuously adjust these numbers every year, every three years? Or what do you anticipate is going to happen with these adjustments in CONE and now in revenues?

MR. ANDY OTT: Well the expectation of course is this will all work and, you know, that the adjustments--you're not going to see, you know, adjustments every year.

There will be an analysis. There is embedded in this an analysis every three years to look at the performance of this and do analysis to determine should there be an update.

So I think the more reasonable periodicity would be three years. Obviously, if we got into a situation where you had non-performance, in other words, some lack of response either in a local area or globally, then of course there would be more. But I wouldn't expect that to be an event that would happen a lot.

I think it would be more of the three year periodic review. And again, whether anything would need to change in that three-year period, you know, I think what's most important is that we have a review, which is a process to allow it. Maybe at first you may see changes, you know, every three years. Whether you would forever, I don't know.

MR. GOLDBERG: Are those filings going to be section 205 filings, just informational filings? What kind of filings do you anticipate?

MR. ANDY OTT: That's beyond the scope of my ability.

UNIDENTIFIED VOICE: 205 is stated in the material.

MR. ANDY OTT: 205, they're stated in the tariff. He could have put his hand on my back --

MR. CHOUEIKI: Now Andy, those filings you would do an analysis for every LDA? So let's say you end up with 15 LDAs, you'll do an independent analysis?

MR. ANDY OTT: You'd do the analysis for these reference locations, yes.

MR. MEAD: I'd like to pick up on Ezra's earlier comment now that he was trying to make. And that is, I gather, that it would be preferable not to try to estimate in advance what expected energy and ancillary service revenues are and make the deduction in the curve, but rather hold an auction where the demand curve is based on CONE, ignoring energy and ancillary service revenues, and then in each year, estimate--and presumably this would be an estimate, based on, you know, some benchmark unit of what that benchmark unit would have made using, I guess nobody is now advocating perfect dispatch, but you know, estimating what these actual revenues are and making the deduction in each year--can people comment on what they see as the advantages and disadvantages of that method?

If you want to speak first?

MS. HOUSMAN: If I could, I can at least say why I proposed this, and I mentioned it in my pre-conference comments as well.

And the reason is that, if the goal is revenue stability, then it seems to me that revenue stability is guaranteeing a certain amount of revenues which would mean that you can net out the energy and ancillary service revenues specifically according to what they are for this hypothetical peaker. And as you say, there is some modeling involved in that.

So that if it turns out that they are earning less than anticipated, they will still have the revenue they need to meet their capital obligations, and if they're earning more, the consumers will not be paying more than was necessary and than was put together under this construct in order to support that capital investment.

The reason this is particularly important is because of, you know, what is nightmare scenario that makes consumers so concerned about this, which is, that if we look back at six years and say, oh, you know, energy and ancillary service revenues were not so high, we'll have a small adjustment, then we go forward in time and there is not a surplus of capacity but in fact the capacity cost is high at CONE or up to twice net CONE plus -- actually plus the revenues, talking about later, so we get to a situation where consumers are paying a very high capacity price and that reflects a shortage of capacity.

But in addition, they're paying very high energy and ancillary service costs but those costs are not reflected in the capacity price. So that it's been adjusted for a small price and yet consumers are paying the big price and basically paying twice this amount of money.

So that's why we feel that it would be very important to use, you know, at least a reality check in terms of adjusting these revenues. And ideally, as is the current proposal in New England, to use real revenues or real modeled revenues, but based on the system conditions at the time of the capacity year.

MR. MEAD: Andy.

MR. ANDY OTT: I am not -- I think there are some significant disadvantages to going back and sort of essentially what you're effectively doing is changing what the clearing price was in the auction because you're essentially taking revenue from generators and refunding it to loads.

Which again, I think the key point here is, if you do this type of annual adjustment, retroactive adjustment, you still need to base it on some sort of modeling. You're still assuming, you know, certain things about units, although you obviously have the locational prices for that year.

I think the disadvantage of doing that is that you have--again it still is dependent on some modeling and the historic approach would allow you to set the price in the auction based on the net.

The demand response, as I had outlined in some of my comments for this hearing, I mean when you set that forward price, that has a fair amount of significance. You have demand response deciding whether it wants to participate or not and that dynamic of going back after the fact and changing it may actually change the dynamic of whether demand/response would have wanted to clear or not because essentially it is not sure what this price would be.

There are some of the other interactions of the bilateral markets and the fact that the forward price is set, but then it changes and there is less forward certainty, if you will.

And I think those other, quote, "features," if you will, may offset some of this concern as long as you do a fair job of estimating the energy and ancillary service revenue based on I'll say the recent history as opposed to I don't see necessarily the big advantage to going year by year because I think the downside of it is this uncertainty that I think is fairly significant.

MR. MEAD: Let me just talk about a couple of things that perhaps people can comment on as you're making your comments.

One is, as I looked at the numbers the biggest source of variance between the Levitan and the strategic numbers was ancillary service, energy and ancillary service revenues. This might take away some of that dispute.

The other is, or another is perhaps that it reduces the incentives for generators to exercise market power in the spot market because to the extent that spot market energy prices go up, well they get the money in the energy market but, you know, it's immediately deducted from their capacity revenue.

I mean if people could just comment on that as well as we go down the line. Does anybody else want to speak on this issue?

MR. PARKER: There are two questions you brought up and again this question of ex poste adjustments. If you've had a good month, or a good year, you retroactively adjust the capacity payment.

On one hand it sounds good in theory, but on the other hand that kind of price uncertainty would interfere with, I think, the proper functioning of either the base resource auctions or any other auction where both bidders and--buyers and sellers are looking at, you know, in effect a curve that they know in advance, not one that's going to be adjusted after the fact.

David you had another question?

MR. MEAD: Let me just pursue that for a second. I mean it's true that this kind of adjustment would create greater risk on what the capacity revenue part of a new entrant's revenue would be, but -- and I don't want to sound like an advocate, but at least playing devil's advocate -- that the total revenue from capacity and energy markets might seem to be more stable because, you know, in essence, at least if you're in the market and you're available, your total revenue from energy and ancillary services and capacity might be more predictable.

MR. PARKER: Only for the unit that you've hypothesized to calculate those net energy revenues. So you may be right for a simple cycle plant with two seven FA machines, but for every other type of technology, combined cycle, coal, whatever, you won't have that one-to-one adjustment. It will be skewed perhaps considerably.

MR. ANDY OTT: Plus the demand response participants also, I'm not quite sure how you would handle them. I think the dynamic they would see, again would create essentially a barrier almost to their participation in these forward auctions.

MR. MEAD: Bob.

MR. STODDARD: Not denying some of the facial merits of what you're saying there, I think what the ex poste adjustment in effect does, is not only are you selling capacity, you're selling a call option on your unit in the energy market.

So far, I think everyone around the table thinks the energy market is working pretty well and I would hypothesize that we probably shouldn't be trying to put this energy market piece onto the capacity market when the energy market is working pretty well.

If consumers want to be hedged, as well they should, they should be encouraged to bilaterally contract in the energy market. There has been no showing that there is a problem doing that and I don't think that linking these two products in this inextricable way of selling capacity plus a call option on energy whenever the price goes above the dispatch price of a peaker, is necessarily the best for the long term robustness of the energy market, which is really where we ought to be focusing our attention.

MR. HOBBS: So if I understand what you're saying then, it is that it would be better to unbundle that. If somebody, if some generator wants to sign such a contract in order to lower its risk, it can do that anyway in the energy market and create precisely this product. But if it wants something different, let it do something different.

MR. STODDARD: Precisely.

MR. MEAD: Okay, let me switch subjects again. If we're going to the estimate, at least conceptually the conceptual idea that PJM has proposed, that we're going to estimate revenues in advance and deduct it from the demand accrue, I guess the big debate here is:

Should it be six years or something shorter?

And as I've read the comments, you know, the generator side thinks that -- well, I don't -- let me ask, is it that in principle six years is too long, or that this particular six years is not representative because the first three years turned out to produce creamy revenues for the generators?

Once we get past the first three years, and you know, in the long run we're all dead and maybe we'll never never get there, but is three years better? Over the long term, is three years likely to be a better estimate than six?

MR. PARKER: As you know, in our report and affidavit we focused very, very heavily on that issue. And no, it wasn't the issue of how many years you incorporate it, whether it's three of six years, but which years you're looking at.

And our position is, or our critique of those first three years in that six-year period, it was not that the market was long or short in terms of supply and demand, but that the market has really changed in terms of gas prices, energy volatility and yes there are, as you said creamy years, but nobody, at least that I've spoken to recently, thinks that we're going to come back to an era of $2.00 or $3.00 gas.

We are in, in that respect, in the energy market, in a different era. I can't promise that the next three years will be similar to the three years that we considered in our report, which was 2002 through 2004, and in fact 2005 had the same kind of results, very lean energy revenues.

We can't guarantee that will continue. But again, those first three years in the original six-year period seems to be unfortunately reflecting an era that has passed.

MR. STODDARD: To build on that, I think in general we have to ask, why is this deduction here at all. And in part, I think it is to hedge consumers. As we say, the hour-by-hour we don't want to do, but we want to make sure there is not overcompensation or under-compensation.

The concern I have with a six-year period preceding a four-year period for a one-year commitment, is that energy market outcome from 11 years ago are having effects on outcomes today.

That strikes me in a market that is as dynamic and evolving as the energy markets have been over the past 20 years as just excessively long; and that we will gain more confidence that any overcompensation or under-compensation is quickly carried through to the market and flushed through by shortening up this evaluation period from a six-year horizon to a three-year horizon.

MR. MEAD: I just have one more question and then if other staff have questions that would be great. This is directed to Mr. Stoddard.

As I understood your comments, you argue that PJM should include a factor to address the effects of daily netting of operating reserves uplift payments. I didn't fully understand that. I was wondering if you could elaborate.

MR. STODDARD: This is a technical issue that I must confess I don't have complete mastery of, but there are more ways to earn money and more ways to have money reclaimed in the market than just by looking at hourly clearing prices.

The point is, the way PJM calculates your total settlement, can include that if you have earned money in one hour, but your total daily spread lost money, there is a deduction that can occur.

And what we want to make sure of is, again, that the total idea is that the compensation received by peakers is fairly reflective. That can't be computed just on an hour-by-hour basis. The tariff is more complicated than that. There are different ways where energy offsets and ancillary service revenues can be offset against losses in other hours.

MR. MEAD: That sounds like you're suggesting that in the modeling, in some hours of a day the hypothetical peaker might have been seen to lose money and over the day might have been seen to have lost money, but in fact in the real world there are these uplift payments that will make generators whole? Is that it?

MR. STODDARD: Perhaps, but the easiest way to say this is that the simulation model they use to compute payments, net payments to generators, needs to reflect the actual tariff operations.

So if there are rules in the tariff that change the payment from other than the hour-by-hour LMP, then the model itself ought to have a correct accounting to make sure that any offsets, extra payments one way or the other, are correctly captured so that we have a correct monthly net payment, given a stream of prices during the month.

MR. MEAD: Andy or Ray, can you --

MR. PICARDI: I was just going to offer a limited part because I think Bob kind of hit a nerve and it's an area where there is committee process and rule change addressing the type of issue that he has mentioned in terms of--and I won't go into the details because it is fairly complicated, and probably he's heard more about segmentation schedules and how it affects peakers and combined cycles and the way reserve payments and credits and payments are made if you run behind, beyond the day ahead schedule--so the bottom line is, you can have your stream, your payment stream change during the day based on the way you operate.

My ultimate point being that, when I took a look at how they're going about doing this, the one kind of item that did hit home that I think was in Bob's analysis was, there are going to be potentially some rule changes on how the energy markets are run, how ancillary service markets are run because we're going through this process and the committee processes within PJM and maybe that we need to look at this as an art like we're talking about it and not only look at history and maybe not so far back as six years, but also what did we really do that is going to change the market going forward, whether it's positive or negative to revenues.

MR. MEAD: Is the import of your comment then that PJM may have underestimated the total -- I can't imagine you would have drawn that conclusion -- but ...

(Laughter.)

MR. STODDARD: I think what I'm saying is that the tariff changes will affect what your historical estimates would be. That if you were to -- there is a difference between what you could have earned historically under the historical tariffs and what you could have earned historically under current tariffs.

And since the current tariffs are what future expectations will be built on, we have a fairly difficult, and I will grant it is a difficult issue, of trying to say, what if the current tariffs were applied to the historical price streams, how much then is the net revenue? So it's getting a mismatching of tariffs and prices.

MR. PICARDI: And I guess what I'm saying at a very high level, having the experience of seeing what the current rules are and what the proposed rule change is that could affect the revenue streams that we would -- I think there is a valid point there is what I am trying to support.

MR. MEAD: Andy did you?

MR. ANDY OTT: I just want to throw in, at one point there was a discussion of a, what I call perfect dispatch model for this and a peak hour dispatch. Peak hour dispatch would actually reflect these operating constraints of units, meaning min run times, et cetera. And certainly, I think in an original filing last August, Dr. Bauer put forth the perfect dispatch as the way to do it.

To be honest, upon reflection and thinking about the modeling capabilities we have, I mean certainly doing it based on the more realistic peak hour dispatch I think would be an improvement and we actually say that in my comments.

So certainly from that, to get more of a practical, you know, as much as we can, to get a more realistic assessment of these revenues given these operating constraint units we actually use in the energy market, certainly we think that would be an improvement on this calculation.

MR. MEAD: Okay. Jonathan.

MR. WALLACH: I always appreciate the opportunity to be able to say that I agree with Bob so, I agree with Bob and I think a perfect example of that is the Scarcity Pricing Settlement that is going to, I think could potentially make a pretty big impact on net revenues for a new peaking unit and unfortunately the historical net revenue numbers don't reflect that.

MS. COCHRANE: Are you done?

MR. MEAD: I'm done.

MS. COCHRANE: Are there any other questions from staff?

(No response.)

MS. COCHRANE: Great. We're actually breaking for lunch almost on time. Why don't we break for lunch now for an hour and come back promptly at 1:35.

(Whereupon, at 12:35 p.m., the meeting was recessed for lunch, to reconvene at 1:35 p.m., this same day.)

AFTERNOON SESSION

(1:35 p.m.)

MS. COCHRANE: Would everyone take their seats so we can get started. Before we get started on topic D, we have one follow-up question from this morning. Tatyana.

MS. KRAMSKAYA: I think in the October round of comments, quite a few people noted that the chosen cost of new entry might not really assure the most efficient and balanced fuel source mix. Would anyone on the panel like to comment on that, on the fuel source mix?

MR. ANDY OTT: Again, I think the cost of new entry is a reference point so that essentially the net cost of new entry, you have the capital and then the offsetting energy revenue, is essentially a reference point which says, okay, here is the cheapest, the least expensive price for capacity.

Obviously if another type of technology, for instance pulverized coal plant, somebody could, in fact, build a pulverized coal plant based on these certain expectations and I think really that's going to be driven more by the balance between gas prices, oil prices, fuel prices, things like that.

A stable capacity revenue stream, okay, will help all types of technologies. The decision on which type of technology to build is more going to be driven by the energy dynamic.

So I think what this is trying to do is stabilize the capacity market and make it, again, a least cost solution in its own right.

So I think having the peaker-type reference is appropriate in that case. It's not intended to have all the information about fuel mix, that's really more the fuel prices than the energy market.

MR. MEAD: Okay, I guess we will move on to topic D which generally deals with, at what capacity level should the price equal net CONE?

First let me ask Andy, I understand that the PJM proposal would have the price equal net CONE where the curve is equal to IRM +1%.

Is it PJM's expectation that the average level of capacity over time would pretty much meet or equal 1% above IRM?

MR. ANDY OTT: If you look at the performance, again of the curve, which essentially is the curve shifting to the right, in other words, that right shift by 1%, it was done based on the analytics, in other words looking at the modeling and the results that we were seeing, as far as again, as we had discussed earlier this morning.

But the goal was not to have the average IRM over 30 years be 15%; it is to make sure we don't most times, very seldom ever, go into a year where we are lower than 15%. So 15 is more the low end as opposed to what we're shooting for for the long term average.

In other words, we want to make sure we don't fall below the IRM. So the concept here was to actually look at performance of the various types of curves and the various offsets et cetera, and what we found was that again, balancing this need to have most times, not be below IRM in the delivery year but have the minimum cost and trying to strike that balance, the analysis indicated the 1% shift to the right was the right answer for that.

MR. MEAD: Let me ask Ben. In your assimilations of Curve Four, what did it turn out to be was the average capacity level relative to IRM?

MR. HOBBS: I'm looking at the Table 1 page 36 of the August affidavit and in the 4th row it says that the average percentage forecast reserve margin--this if four years ahead--is 1.8% - 1.79% above IRM. So it's a little bit above it.

MR. MEAD: Okay.

MR. HOBBS: That's page 36.

MR. ANDREW OTT: That would equate to, in what we were discussing, 16.8.

MR. MEAD: Okay, thanks.

MS. DEBORAH OTT: Can I just ask a question?

MR. MEAD: Go ahead.

MS. DEBORAH OTT: Does that mean that that was your target that you were aiming to hit one point roughly 8% above IRM? Was that what you were aiming to hit?

MR. HOBBS: This was the result. This wasn't the target, but this was the result. So the curve that had the kink at 1% that under the assumptions made in this particular -- this is the base set of runs; under different assumptions you get different results -- but under the base set of runs you get something that was 1.8.

On Table -- I better not guess the number -- there are the sensitivity analysis, this would be Table 9 on page 57, the ranges were from 1.3 to 2.1 percent above IRM, in terms of the average, depending on the assumptions that you put into the model. So this was the result of the calculation.

MS. DEBORAH OTT: So IRM was the target, is that it?

MR. ANDY OTT: IRM, again meeting IRM in most years was the target and most defined in our case, around 98% of the time.

MR. HOBBS: Exactly.

MR. ANDREW OTT: That was the target.

MR. MEAD: Go ahead.

MR. CHOUEIKI: I was going to say, comparing IRM is 15%. They do all these runs and they measure the results of the reserve margin and they compute the difference between that result and 15 over lots of trial and basically that's how their average came.

MR. MEAD: Just in terms of the mechanics, as I understand it, there would be the base residual auction four years in advance and then--let me see if I got this right--there is either the second or the third incremental auction, at one of those incremental auctions you will make an update of your forecast and if your forecast turns out to be now larger than what you originally forecast, let's say by 1,000 megawatts, then in this incremental auction you would go out and procure another 1,000 megawatts of demand, of capacity. But if the forecast is now smaller than what you originally forecast, then you make no adjustment.

Is that right?

MR. ANDY OTT: Correct.

MR. MEAD: It would seem to me that the net result of that then is that perhaps the average amount of capacity that you end up with is going to be perhaps larger than what was developed in Ben's model.

I guess the other point is: If you had known in advance that your forecast was 1,000 megawatts bigger than--how do I say this?--if your base residual auction presumed 1,000 megawatts more of demand, the amount of capacity that's purchased, if there is any slope to the supply curve, probably would have resulted in less than an additional 1,000 megawatt of purchases than in fact you made.

MR. ANDY OTT: I'm not sure I followed that. I'm sorry.

MR. HOBBS: If the spiker was horizontal--

MR. MEAD: If the spiker was horizontal, then adding an extra 1,000 megawatts to your forecast in the base reserve auction would get you 1,000 more megawatts of capacity purchased in the base residual auction.

MR. ANDREW OTT: Correct.

MR. MEAD: But if there is any slope to the supply curve, you would end up --

MR. ANDREW OTT: It could be less.

MR. MEAD: Right. Okay. Now in terms of the issue of at what capacity level should we be targeting CONE to, Mr. Stoddard in his written comments used Steve Stoff's methodology in the New England testimony and estimated the percentage, if I got this right, the percentage of time that the PJM curve would result in capacity less than IRM and you drew the conclusion that it would be, was it 24%?

MR. STODDARD: I believe that's the number, yes.

MR. MEAD: Okay, which is marketedly different from Ben's estimate of 2% and I was hoping to get a little dialogue on that.

MR. STODDARD: I'll be very happy to do that.

MR. MEAD: First, can you summarize for the record basically what's Stoff's methodology was that you applied?

MR. STODDARD: Yes. Dr. Stoff in his testimony in the New England LICAP case developed a model to evaluate different LICAP curves.

At some level it is a very -- it assumes a lot of things and then plays out what the effects of a distribution would have that would result under the curve.

The critical thing, and a place where there is a difference in the model, and I'm not going to justify one or the other, in Professor Hobbs' model he is developing the scatter of outcomes through the model. That is to say he is not assuming any historical distribution about how far above or below the target installed capacity would occur. He is trying to estimate that through the model.

Dr. Stoff's model that I modified, looks back historically, or uses any information you want to hypothesize, about what the scatter is and then says: Well if that is the scatter around a target, this curve has a target that is poised at a certain point, and by the way the two models agree exactly about where the target is of the model.

MR. MEAD: Which is what, 1% above of 1.79?

MR. STODDARD: 1.8% above. The way the kink is drawn it penalizes or it will tend to skew the outcomes just a little to the left of the kink -- to the right of the kink, I'm sorry.

Where the two models were different in the real core of the difference in results is the assumption about how tightly focused the outcomes would be around the target.

In Professor Hobb's model, he had a very tight scatter around the target. I looked back at historically what the scatter has been for PJM and said, conservatively I thought, we will assume the variances half of what it is because we'll have this organized market process, and if the variances is half of what it has been historically, what would the scatter be?

And under that condition, which is about a factor three times higher than what Professor Hobbs -- half the variant -- while we come up with the same mean for the distribution line, we come up with very different periods in which we are below. And that is, you know, just highlighting the fact that we're really relying on the very precise accuracy of Professor Hobb's model and manage to hit a target if we relax that assumption and said well, it's going to be better than it has been historically, but not as good as some models might predict, then there is potential for downside.

When I shifted the target, the kink rather, from the 1% kink to a 2% kink, which also then shift up the average outcome, then I find that at that point, we're only below the target by about one year and 10 we will miss the IRM under this higher variance assumption.

MR. HOBBS: There is a very important distinction between the variability of reserve margin year to year in the year, which Bob presented a table in his filing showing that the experience level of variability has been about 5% in terms of a standard deviation.

And the variability four years ahead of time against a projected weather-normalized load. So when a critic says to me that my models, my models seem to show, and this is again in Table 1, that the standard deviation of the forecast reserve margin over IRM was .9% and that historically it has been 5%.

And so this was an apples and oranges comparison in the sense that indeed my model shows that the variation in the year including weather variability is about 5%, this is historically from experience, but four or five years ahead of time, it's quite a bit narrower than that because there is your weather-normalizing and you're using expected economic growth.

So if you use my standard deviation that I derive from the model of about 1%, then you get this 98% reliability. If you instead just make an assumption and say, well, let's assume it's 3% of 2 %, well you said you cut the variance in half, that would be about 3 , that means the standard deviation is about 3/4. So that is .235, in what units?

MR. STODDARD: I'm doing this off the top of my memory, I believe it is .0235.

MR. HOBBS: Because if the historical standard deviation was 5% then if you cut the variance in half, you would get a standard deviation something on the order of 3.5 percent.

MR. STODDARD: I think the 5% is high. I think my table shows a historical of 3.7.

MR. HOBBS: Okay, those could be verified.

MR. STODDARD: By the way I should say, Dr. Ogar has requested and I will provide the electronic backup for these spreadsheets so you can use them and understand the results.

MR. HOBBS: Okay, so the key issue then is you assume the number with a much lighter variance and of course that does present a greater risk of missing a target and my point is that I think it's quite reasonable actually to expect that four years ahead of time you will be within a rather narrow range, considerably narrower than what he suggests there and as a result I think the reliability that we're talking about, 98% is probably more reflective of what would be experienced.

MR. STODDARD: My counter point thought of what we're trying to achieve, is not reliability four years in advance, we're trying to achieve actual reliability. We're trying to make sure that we have iron in the ground to meet necessary condition.

And so what we need to be looking at is not a long term forward margin, but whether we've done a good job about giving how load growth has actually moved, how economic conditions have actually changed, whether units we thought were committing on the system actually show up, that's the number we care about.

Now there can be weather within the year but I agree its different but there is a difference between the two of us.

MR. HOBBS: So this 98% is the probability of making it, of thinking you're going to make it four years ahead of time. Certainly in the year, the probability of not making IRM will be bigger than that 2%.

MR. MEAD: Of IRM which is 15% of what is it, the delivery years peak load, is it previous years of what?

MR. HOBBS: It is essentially 15% of the forecasted load for the delivery year, for the peak.

MR. MEAD: And the forecast is made just before.

MR. HOBBS: Just before.

MR. MEAD: Okay.

MR. HOBBS: So when we go out, for tomorrow, probably more important for tomorrow, but the 15% is essentially a one year, based on a one-year ahead. it's not really looking further forward.

Obviously if you go four years out, there is additional uncertainty. Obviously one way to deal with that uncertainty would be to increase the IRM. Another way to deal with it is keep the IRM and have this phenomenon you talked about, was have the load forecast adjustment on a nearer term, and that's what we chose to do within the RPM, again balancing the various, you know, obviously you don't want to over -- the higher these reserve margins gets the more expensive and there is a balancing act.

So we chose to keep, because even though there is more forward uncertainty, and if you actually went through these IRM calculations, put the longer term as I put in my testimony for tomorrow. if you actually look at the longer term forecast uncertainty, that you would actually have a larger load forecast uncertainty, which result in a larger IRM looking forward. we've chosen to manage that differently within the model and keep the 15% one year target. If I didn't lose you all in that.

MR. MEAD: So your results, I'm trying to understand what this 2% below IRM means. It sounded like your model results in capacity four years in advance being falling below the four years in advance IRM 2% of the time but the IRM calculated just before the delivery year could be bigger?

MR. HOBBS: Randomly yes because you have random economic growth and even if it's on a weather normalized basis that's right. And so there would be more spread. Instead of a 1% standard deviation you would have 3, 4, 5, depending whether you have weather in there to not. You would have a wider standard deviation and more of a probability of being below the IRM.

MR. MEAD: So your results are different from Bob's but are they consistent with each other? That is, is Bob's estimate of, I guess capacity just before the delivery, your 24%.

MR. STODDARD: I think in fairness, my variability numbers are based on an after the fact. You compare the installed to the actual peak. So there is a number between ours--

MR. MEAD: Okay.

MR. STODDARD: --which is the weather going into the planning year you hit your target.

I've looked at a variability that says after the fact, you'll find that 10% of the time you will have missed. But there is some number between the 2% and the 10% which is how often walking into the planning year you will miss and I don' have that information to tell you how much of the eight percentage point difference is the change in the information between year one and year three of the planning process, and how much is because of weather changes during the course of the year.

MR. MEAD: Okay, so getting back to the issue of our objective, well, if our objective is one day and ten years, what standard deviation do we want to look at if our objective is we don't want to fall below IRM, which IRM historically have we -- I mean it sounds like historically, what we've been concerned is meeting IRM just before the delivery year, not afterwards, but not four years before either.

MR. ANDY OTT: And again, I think that's exactly right. The 15% is really the metric that has remained. The analysis that Ben had done was again looking forward in time at the performance and a gain that's one of the reason, or that is the reason why we have the load forecast adjustment which was embedded within the RPM protocol where the second incremental option we actually validate.

In other words what Ben has said is yes, 98% of the time on a four year ahead basis we'd be fine, but there could be things changed in those years as you get closer, which could be higher load, whatever and that adjustment would get made in the second incremental option to take care of that.

Another way to do it would be to just up all the parameters. Say instead of shooting for 15%, you shoot for 16 then I won't have that problem, but again that would get more expensive, and it was a balancing act.

So the point is, it hasn't changed what our target is, but we're not confirming, you know, entities need to lock in resources to meet those targets on a four-year ahead basis then we reset, reevaluate the load forecast performance on a near term basis and do a minor adjustment if we need to.

That's essentially how we deal with this differential uncertainty I think you are describing.

MR. MEAD: Just one thing and then Janet. Do you agree that the objective should be, you know, minimize the percentage of time by which capacity falls below IRM as forecasted just before the delivery year, and if so, what implications does that have for where we set CONE.

MR. STODDARD: I agree that the right time to look at this is walking into the planning year, have you met your target?

I think unfortunately we don't have a record on whether the 1% does that. I think we do have record that suggest that it could be miss more often than the 2% that's been proposed. So, you know, my bias has been, as I've said before, and I reiterate, I think we should be careful in building this market to make sure that we have a successful first auction and that the parameters are set so that we can attract the entry we need to solve the near term reliability needs.

And that means, perhaps targeting the curve a little to the right and perhaps a little higher than PJM has proposed in order to make sure that one works and that we have some realistic market based way that automatically, without having to have section 205 contested in this reiteration of this procedure again, adjustments to the curve so that we're sure that they are working as expected and not producing prices that are either too high or too low so that we're getting the right quantity.

MR. MEAD: John.

MR. WALLACH: I think the answer is that what you want is over the long term on average to meet your 1 in 10 loss of load probability target.

Now, from my perspective there is a fair amount of art involved in going from 1 in 10 LLP with a specific reserve margin percentage and that that when you say oh, 15% is your target, that there can be some upside uncertainty built into that number.

In other words, your reliability modeling where you are trying to meet 1 in 10 LLP might not come up with a number that's 15%, it could come up with a lower number but in acknowledgment of uncertainty, forecast uncertainty and modeling uncertainty, and all the other assumptions, heroic or otherwise that you have to make when you are doing your reliability modeling, you might put in a fudge factor.

So when we have a model that over a hundred year period on average misses IRM in two years out of those hundred years, that doesn't imply that you haven't met your reliability target and not withstanding all my concerns about the reasonableness of trying to model the next hundred years and the effect of a particular demand curve on system reliability, I think we need to keep those numbers in perspective and just because in two of those hundred years you didn't meet 15% does not mean that you did not meet your reliability target.

MR. MEAD: Yes.

MR. CHOEUIKI: I was going to say, you know, that 1 in 10 years could be done also at the LDA level because you're going to have the setting up the reliability requirement and then PJM taking that number and saying, okay this is what it's going to be for anyone who wants to be in our footprint.

And if it turns out to be, you know, like the gentleman said, 14%, you can meet it with 14%, 1 in 10 years and 14%. So that should be the number.

But to go back to the issue of the simulation, the simulation results change even from the benchmark if you just change the risk factor or if you change something by more than 1%. So we're arguing 1% and the issue is when you change that, it clear to make the investors risking you instead of risking us, you run the numbers, your IRM under your probability of exceeding IRM for curve Four which is the IRM plus 1, could be less than 98%, by more than 1%.

So we're arguing 1%, what should be -- I think our opinion is IRM should 1 in 10 years and then basically it should be LDA dependent, whatever the reliability organization sets that to be the reliability number, that should be it.

MR. MEAD: Seth.

MR. PARKER: I recall going through the model that Dr. Hobbs prepared and being struck by one key area of uncertainty, which is investment behavior and it's very hard to get any forecast model right especially when you're trying to model some kind of behavior.

There are many variables, cost of capitals, all sorts of parameters that enter into it. So the advantage of a model like this to compare alternatives, not to believe any one set of results, it's just too fraught with uncertainty.

Given that, I think it's prudent to set the VRR target at IRM +1% because there is uncertainty and if we have to err on one side or the other, it is probably better to err on the side of being cautious. That will do it.

MR. MEAD: As I understand it, one of the key factors in PJM recommending its particular curve of IRM +1 rather than something smaller was that total customer costs would be lower at IRM +1 compared to IRM.

MR. PARKER: If I may just say something, that's the beauty of the demand curve, a sloped demand curve, that it's self-correcting in that regard. sure you may end up contracting for committing more capacity, but at a lower price and it tends to compensate quite nicely, and that's in addition to or aside from the fact that the more capacity you have in the market there more competition there is in the energy market and consumers also benefit from lower energy prices and less energy volatility.

MR. MEAD: I'm getting a scowl from Andy. Maybe I was not reading these tables, but I thought if you wanted to compare IRM versus IRM +1, that total

MR. ANDY OTT: For the same slope of curve though?

MR. MEAD: Yes.

MR. PARKER: Shifting right at the curve so Curve Three has the kink at IRM, curve Four has the kink 1% over so it just shifted everything over to the right and if you, over the sensitivity analysis, if you compare pages 55 and 57, we tend to see that under nearly -- I'm just glancing, it looks like nearly under all the assumptions, we're actually over by 1% is actually better in terms of consumer fault.

MR. MEAD: Just if we look at Table 1 on page 36, well, let's see, consumer payment, the last column, consumer payments -- well that's consumer payments with scarcity.

MR. HOBBS: Scarcity and capacity both.

MR. MEAD: Okay, so Curve four has lower consumer costs and more reliability.

MR. HOBBS: Right and the tables I was contrasting on 55/57 show that that robust over all the different assumptions, that that's the rank order that you get. You do want to shift it over a little bit to the right. No matter what you assume about all this behaviorals.

MR. ANDY OTT: Right, and again, I was thinking your were -- I was not realizing you were talking about vertical versus sloped or whatever, you're talking about two sloped curve side by side.

MR. MEAD: They look exactly the same except one is shifted 1% over.

MR. HOBBS: And again that has to do, absolutely the reason we picked the curve that was shifted to the right is it performed better from a reliability perspective in addition to lower cost.

MR. MEAD: I presume that customer representatives don't agree with that.

MR. HOUSEMAN: I don't disagree.

MR. MEAD: Well, does anybody disagree with that quality of the result and if so why?

MR. HOUSMAN: Do not disagree that in the model that's what's found so that if the model is an accurate representation of the investment environment in PJM, then I suppose that would be the case, but I don't believe this model has ever been validated with any empirical data or even of reviewed or audited in particular depth and with all due respect to Professor Hobbs I do a lot of modeling do and the first thing you say is well, I know my model is wrong, it doesn't represent the system so I'm going to look at the ways that it doesn't represent the system and see if those distortions are going to be particularly important.

In this case, those distortions are extremely important and I could create a model, you know, just as well that had a great barrier to entry for new generation and what would come out of that is that the higher -- the further you move that point to the right, the higher the cost would be to the consumers without benefit to reliability.

I mean it's almost like magic this idea that the more you over bill the better it is for consumers. Now I mean maybe my friends from the generation side believe that magic, but frankly you're saying this is good for consumers but we just don't see it and the model doesn't convince us. The model has to be -- you can't base decisions on this model unless you can really make the case that it accurately represents the investment environment that we will be seeing in PJM.

MR. MEAD: So it sounds like the main reason that you don't believe Ben's result is because you think because of the barriers to entry that you see in the market.

MR. HOUSMAN: Well there are a number of reasons.

MR. MEAD: The -- I mean, as I understand the big driving factor is that if you think that there is enough entry and that various entry are low, that more capacity get to lower energy revenues and also there is what, I guess less volatility so that, and that lower volatility results willingly in generators investing in more because their cost to capital is lower.

MR. HOUSMAN: If the real market were that smooth and simple that anybody could enter and just look at these and frankly if they believe the projections of energy revenues that are based on a curve, which I also have taken some issue, but then I guess that's what would happen. But I just don't think that reflects.

MR. HOBBS: If I might suggest the result of using your assumptions which is that you won't get entry, easily simulated and this is what precisely will happen, you won't get entry because of barriers entry market power that you will lose the back stop that you won't get. You either have to shift the curve way, way to the right or way, way up and that the whole thing has failed.

I guess what you're saying is that you don't believe the market is going to respond, that we shouldn't have a capacity market altogether.

MR. HOUSMAN: I think there is a great risk of that and I think were that to happen, I'm just not sure what we'll be sitting here talking about -- we'll surely be talking about missing money, I tell you that. But it wouldn't be the generators' money, it would be the consumers' money.

MR. HOBBS: I certainly welcome the opportunity to respond to thoughtful criticisms of the model. If this is a good time I'm glad to do it, or if you want to wait until later.

MR. MEAD: Let's see.

MR. HOBBS: But I realize this is also not the question you asked.

MR. MEAD: Bob, and then Jonathan, and then Hisham.

MR. STODDARD: When we were debating in New England the LICAP market I might have had more sympathy with the argument of well, we'll pay it but how do we know it comes. Because in fact, there was no linkage between the market and building. There was a reliance on spot markets to work. That was one of the reasons why states hated it.

I don't understand that criticism about the RPM Model. The RPM Model creates a binding commitment on people to enter. So if you've paid you'll be there.

I have not seen any evidence put into the record that shows that there is a systematic barriers to entry, that there are failure to have transmission interconnection. There is an open access transmission tariff in this market.

I have not seen any problem with obtaining sites. We are looking at fairly broad geographic markets. And to the extent that the markets are too narrow we might. But so far PJM's markets are fairly large, including in almost every case suitable sites -- many suitable sites for generation, not all of which are controlled by distinct generators.

You are asserting a problem that I do not see that there's been any evidence that we are going to have trouble with entry. Entry can be sited economically by a large range of people. Then the market ought to work and create a binding contract where people have said they're going to come on, will have every correct incentive to be on line when they say they are.

So this paying for promise is not applicable here. It's paying for a contract. And the RPM looks more like a procurement mediated by PJM than it does some sort of wish and a dream.

MR. HOUSMAN: But Bob, I'm not talking about whether people are going to honor their commitments once they've cleared in the capacity market. I'm asking whether people are going to be able to make those commitments four years in advance and say that they're going to be able to place capacity, and whether they'll have the incentive to do so.

MR. STODDARD: You've asserted that's a problem but there's no evidence of that.

MR. HOUSMAN: And there's no evidence that it isn't a problem but if it fails, if it is a problem it's going to be very, very damaging and painful to consumers.

MR. STODDARD: Every time this commission approves market based rates there is a finding about the competitiveness of entry and the lack of control over sites. That has been litigated.

If you believe there's evidence to the contrary I think it belongs on the record. But absent that evidence it's hard to damn this market for a conclusion that you don't have evidence to support.

MR. HOUSMAN: I really don't think the burden of proof is on my side. I think the burden of proof is that the model on which this analysis is based is a valid representation of the market. And if that hasn't been established I don't see how we can sit here and talk about the implications of these curves based on the model. I just don't see it.

MR. MEAD: Jonathan, do you have a comment?

MR. WALLACH: I came at this tech conference from a slightly different angle. To cut to the chase, even if we accept the model for what it is it is possible to craft a curve which does not cause or mitigates the harm that consumers are so concerned about, which has to do a lot with what's happening in the here and now, not 50 or 70 or a hundred years from now. What are the immediate to near term impacts of a demand curve?

You can use Ben's model and you can come up with curves which address that problem, yet which produce comparable results in the long term, comparable to PJM's preferred curve.

So we can spend a lot of time debating the merits of the model, and I've certainly spent a lot of time crafting an affidavit about the merits of the model. Ben hasn't yelled at me yet. But I think there's another way to go at it, which is to say sure, let's take a look at the model and what does it tell us? I think what it tells us is there are a number of different ways to craft a solution that gets you to the objectives, get the same results, and avoid some of the problems that consumers are so concerned about.

MR. MEAD: Hisham?

MR. CHOUEIKI: Actually I wasn't going to get into that discussion but I was going to make a statement about these numbers.

There are the means and there are the standard deviations. So when $71,000 a megawatt year there's attached to it a standard deviation of $48. So if you were to take that $48 a multiply it by 15 percent of total PJM peak you're talking about a billion dollars in error. Just basically because you have random noise and you have uncertainty. That's a very large number.

So I caution you to just don't look at the 71 and 74 and say okay, 71 is better so I'm going to pick that curve. There's lots of uncertainty that we have to think about too. That's just my two cents here.

MR. MEAD: Go ahead, Andy.

MR. ANDY OTT: Just to summarize what the analysis was utilized for. The analysis was utilized to take a family of curves and essentially look at the performance of the curves using two metrics. One was consumer costs and the other was reliability. And essentially to evaluate those curves using similar assumptions for each curve against each other using the best we could come up with in a neodynamic investment-type model.

The assumptions have been questioned but the point was, from my point of view making this decision for PJM, I said we have to be reasonable sure that the assumptions that we're looking at here are robust over a fairly wide range. So we had various of these parameters were modified, and you see all those tabular results.

What the results consistently had shown was under all those various different types of assumptions -- whether risk aversion or whatever these are -- you see the same pattern, which is essentially the one percent offset performed better throughout all that.

And I think it was a reasonable way because, as has been stated here, this is not something where it's necessarily science alone. There is a lot of science and mathematics involved but at some point there has to be a decision made. I think this type of analysis is essentially a prudent way to do it because it's given you an analytical assessment of what you can expect for performance.

MR. HOBBS: If I may follow up on that. We can use Jonathan's proposed curve as an example of that sort of analysis.

Jonathan had proposed dropping it vertical at IRM plus one percent. Please correct me if I'm wrong. And then retaining the slope segment to the left here. And that under one particular set of assumptions in this Table 1 on page seven of what he filed a couple of weeks ago he shows that his proposal would have total consumer payments of $78 on average, using the model under a set of assumptions, and the PJM curve would be 72. And that difference is not as large as a lot of other of the cases.

To follow up on Andy's point, I think it's important to look at a whole range of assumptions and see what the pattern is. So this was one particular set of assumptions where Jonathan assumed that existing bidders bid $20,000 and new bidders bid $44,000, which is one possible set of assumptions. But if you make any other sort of assumptions then the difference between these two is a lot greater.

I'm not going to say that this set is right and that set of assumptions is wrong. I'm saying the whole pattern is is that in general you get the PJM curve having a slope to the right results in better consumer payments under any of these assumptions than this proposed curve.

I should also point out that there is a mild discrepancy in assumptions in that Jonathan, you are concerned about the situation where existing capacity bids nothing and so the demand curve sets the price. That is inconsistent with an assumption that existing capacity bids 20,000 in this particular run.

So I think in a sense that's an admission that you're not quite sure whether this is the right assumption or not either in terms of bidding. My only point is that there is a lot of uncertainty about these things so you have to look at the entire pattern.

MR. WALLACH: Actually, I was quite comfortable with the $20 per kw a year assumption because if you look at the supply curves that PJM developed for their own near term, short term simulations that they did, which somehow fell below the radar screen or whatever the expression is. It just disappeared from view. But we should not forget that PJM did do a number of simulations of the RPM Model and option clearing over the next four years or so.

As part of that they developed supply curves for existing capacity and it's those supply curves that I looked at that gave me comfort assuming with assuming as a baseline that $20 was reasonable for existing.

So I agree with you that you can have a range of assumptions but that range needs to be reasonable. In my mind certainly assuming zero as a baseline assumption is outside of that range of reasonableness.

I also want to say that not only is it the assumptions about existing capacity that are important but it also is what you assume in terms of new entry, what they're going to bid. And that's very important in terms of the model because the model is driving everything off of profitability. So built into the model is an assumption about what the actual cost of new entry is. If new entry is going to clear, whether it would be a profitable price.

So since you have that built in there then by necessity you have to assume that new entry is going to bid at that cost. Because if you're assuming something less then what you're saying is that you're forcing the model to clear new entry at less than profitable or below cost levels, and that exaggerates the volatility and the volatility is what drives the profitability and utility functions and you get skewed results.

So again, there can be reasonable range on your assumption about what new units are bid but zero is not the answer, nor is 25 per kw the answer. Again, that's just well below, you know, what your model says would be a bid at cost.

MR. HOBBS: He's referring to Table 3 of my filing a week and a half ago where I did a sensitivity analysis of a range of assumptions but all of them assuming that new capacity is bidding at $25,000. The dominant result remains that in terms of comparing different curves the IRM plus one percent curve remains better.

My sensitivity analysis from my affidavit last summer, when you look at the high case of bidding $44,000 for new capacity and 25,000 for existing capacity that again, the rank order in the curves remained such that the PJM proposal is definitely preferred to curves one, two and three. And in most of the cases it looks better than curve five.

MR. WALLACH: Could I just add one more thing?

When Ben was characterizing what I did, it's correct, I put forward an alternative curve which goes vertical and had those simulation results that it had, which I assert are comparable.

There is a very important aspect that we're not dealing with here. The reason we're thinking along the lines of a curve like that is because PJM's simulation modeling did not look at what's going on in the near-term.

In the long-term simulation -- years 10 to 110 -- PJM curve may look better than another curve. And it may look slightly better than the alternative curve that I had in my prepared statement.

But when you look at it compared to what the near-term impact would be, which is what's going to happen next year and the year after and the year after where we're in a situation where we've got 25 percent reserve margins and we're well in excess -- those cost impacts, the multi-billion dollar cost increases could swamp any apparent long-term simulation result benefit that's coming out of Ben's model.

It's just unreasonable to ask consumers -- it's almost Biblical to ask consumers to suffer through many years of multi-billion dollar increases in the hope that some day we'll reach the promise land of long-term equilibrium.

We need to reintroduce that near-term perspective and those near-term concerns back into this conversation. That's why consumers aren't sitting on the other side.

MR. MEAD: Are you suggesting that over the long-term -- well, how do I say this? That you might be willing to live with the PJM curve several years down the road but you need a transition?

MR. WALLACH: No, what I'm suggesting is a couple of things. One is I don't know what this industry or the world is going to look like 50 years from now so I think we need to have a little humility here when we're trying to model the long run -- besides the fact that we'll all be dead.

So when you're stacking up near-term results against long term modeling results I think you need to put a thumb on the scale of the near-term. A large thumb on the scale.

Secondly, it's not a matter of saying if we had a transition and then we could transition to PJM's curve. Because from my perspective you can use the model which was the basis, as Andy said, for their decision about what curve to use and come up with a different curve which avoids those near-term problems and gets you the same result.

MR. MEAD: Bob?

MR. STODDARD: John Estes was fond of saying I will surely pay you Tuesday for a hamburger today. Much of what you propose there sounds like that.

We don't need to make any short run payments now because some parts of PJM -- some parts of PJM don't have a reliability issue. But don't worry: when they do we will make sure they are adequate payments.

That sort of promise to pay in the future provides a huge amount of regulatory uncertainty and a great deal of risk.

We have in parts of PJM, many parts of PJM, a pressing need to improve infrastructure investment now. We have to build a market that accomplishes that. Proposals that -- and we'll talk about the exact slopes later today, but proposals that include large vertical cliffs are intrinsicly poor at balancing off payments today and payments tomorrow for investment that has to occur. And investment, once it occurs, is going to stay around for a long time.

I wholeheartedly agree with the general conclusion of Professor Hobbs that providing some stability, not absolute levels, but providing stability, smoothing over time of these payments provides better performance for everyone in the market.

There are places that need that today. We need to get the signal out today and investors need to have confidence that the structure we're putting in place is going to be a place they want to invest their money instead of investing it in New York or New England or someplace else that has a better compensation structure, fairer.

MR. WALLACH: I have to disagree. It's a point I made earlier this morning. There is no cliff when you're talking about a forward procurement. When I say forward procurement I don't necessarily mean RPM. I don't mean a mandatory forward procurement. I don't mean it has to be four-year forward procurement. But if you've got forward procurement and an opportunity for new entry to participate in the market and set the clearing price you get that stability around the price that you need.

You don't have the kind of binary or the purported binary clearing that you have with certain curves once you go from prompt clearing to a forward kind of procurement.

MR. STODDARD: Jonathan, that's true if there's a need for new build each and every year. However, if we have some years a need for build and some years not, which in small LDA's is likely to be the case, then unless there is some way of having robust bidding -- and as we've talked about in the paper hearing, I'm concerned that the mitigation imposed on existing bidders is quite severe -- then there is a distinct difference, a jump in the supply curve between existing which will be very low potentially, up to the fair price there. That jump in the supply curve and a jump in a demand curve will in fact create these binary prices that characterize the market today.

MR. WALLACH: First of all, let me say --

MR. MEAD: Mr. Picardi has had his card up for a few minutes.

MR. PICARDI: I wanted to jump in in support of Bob because I think when we looked at the curves -- even the curve that's a little bit truncated -- and I feel like we've kind of launched past the section of the program we're supposed to be in now, but since we're there and talking about it.

That's what we could see. You look at the curve and you wonder when you see where it drops to zero how you're going to be there, even in a forward market that's way out there.

I continue to revert back when I think about that to the FERC order that said price signals to retain existing generation. And I don't see how any type of curve that has a cliff that's too soon when you look at compared to where ARM is it can provide any meaningful price signals to existing generation and give them any incentives.

And I combine that with the fact that, as Bob was saying, that some units in the market that don't run off and have to deal with cost capping are not going to have an opportunity to get very little revenues to contribute to their fixed cost. So what are they going to put in maintenance? Or what interest are they going to have to stick around?

So I think we can take Jonathan's approach and we can look at the short run itself. We're here to consider consumer interest, but let's also talk about the interest of steel that's in the ground now. And if you look at a cliff and you're not getting any payments at all that has an affect too.

MR. MEAD: Jonathan and then Ben.

MR. WALLACH: A cliff does not mean that the price goes to zero. A cliff, the vertical portion, means the price will clear at where the supply curve crosses that vertical portion of the curve. So the marginal offer will set the clearing price.

MR. STODDARD: Marginal mitigated offer.

MR. WALLACH: Marginal mitigated. You're talking about in an LDA?

MR. STODDARD: Yes.

MR. WALLACH: That's an LDA -- not to get into paper hearing issues here, and I don't really want to talk about mitigation. But the issue in terms of LDA's that Bob raised in terms of well, the smaller LDA's may not have need for new entry every year. Let me just say for the record that it's CCR's perspective position that that's too small of an LDA.

If you've got an LDA where a new unit coming in swamps the market and fills up demand for several years then you're talking about a market that's not a market. It's too small to be competitive. It will need market mitigation. It will be too lumpy. What you should be doing for an area like that is investing in the transmission infrastructure to broaden the market so that that LDA is no longer in existence.

MR. HOBBS: I wanted to address the cliff issue. There is some empirical information and that is from New York State. Since the implementation of their demand curve the ISO and the New York Public Service Commission have both reported that the variability of capacity prices have gone way down. Just as our model predict and just as common sense would say: getting rid of the cliff lowers variability of prices. I think we both have logic and evidence to support that.

MR. MEAD: Seth and then Jonathan and then if there are any other comments from staff. Then I think we may take a break.

MR. PARKER: Since we've transitioned to this issue of whether the demand curve should have a vertical segment or not --

MR. MEAD: Actually I'd like to defer that issue until after the break.

Your turn and then we'll take a break.

MR. WALLACH: Two responses to what Ben just said.

MR. MEAD: Tatiana, then break.

MR. WALLACH: Seeing as New York is so near and dear to my heart, first of all, the demand curve has had no impact on price volatility in New York City. The New York City market is not competitive and prices have always cleared at the cap level. That's one.

Secondly, you can't compare -- Even for the rest of state market in New York, you can't compare that construct to what's being talked about here because it's a short-term, month-to-month option.

If you had started with a construct which did not have the demand curve yet had a much longer commitment period you would have seen very different results than what you're seeing now where you're comparing a month-to-month construct with no curve against a month-to-month with a demand curve.

MR. MEAD: Did you have a question?

MS. KRAMSKAYA: I wanted to go back to an earlier issue that was raised with regards to the assumptions in Professor Hobbs' model. This was with regard to new entry.

As far as I understand, in Table 9 in the affidavit that was submitted last year, sensitivity runs five and six indicate that there was analysis as to different levels of new entry, mainly at five and nine percent of existing capacity.

Am I understanding this table correctly?

MR. HOBBS: Thank you for asking. If I go back to page 50 where I describe the sensitivity analysis, in Table 2 sensitivity analyses five an six basically have different levels of assumptions of the responsiveness of investment. That if you increase profitability how much more investment will you get. Number five is a relatively low number; number six is a relatively high number.

So when you look then at the results on page 57 then we see that at least for this curve it hardly makes any difference at all and the main reason is that investment is occurring at a relatively stable rate for this curve. I believe it makes more of a difference with some of the more vertical curves.

In my filing a week and a half ago I looked at a related assumption which capped the amount of new additions that could occur because that issue was raised by one of the earlier filings. I believe that is page seven, Table 2. So imagine that you could get a maximum of 10 percent of the existing capacity roaring in if profitability is very high. What happens is that it changes the consumer numbers slightly but doesn't change the rank orders of the curves.

But we pegged this right away as a very important issue that we don't know how responsive generation would be. On one extreme you have Ezra's point that he doesn't think we'll get any generation whatsoever. I didn't look at that assumption, that's true, but I did look at a range of assumptions and the rankings of the curves remained robust.

Does that help?

MS. KRAMSKAYA: It does. I guess this was my question with regard to Mr. Housman's criticism, and I was just wondering if that's still valid. Or I guess the question was as far as I understand there was a zero percent assumption --

MR. HOBBS: I could have put a zero percent assumption and then everything would have to be provided by the back stuff. All the curves would fail then.

MR. ANDY OTT: You mean on zero percent essentially you're saying the market fails. What Ben had done is say if you have a general reluctance to investment but eventually they will, if there's enough profitability -- meaning the prices have to get higher.

The robustness of the assumption is it's reasonable to assume if you through a high price long enough someone is going to invest. So his lower end was testing that.

MR. HOUSMAN: I don't think my position could be characterized as saying I think there's a zero percent investment throughout PJM. I do have to take a look at what Professor Hobbs has pointed out here and I'd be interested in studying that a little bit further.

My point is just that I think that the ability to add seven percent in every LDA, which is what the maximum capacity addition -- seven percent of existing capacity every year is wildly optimistic. So maybe somewhere in between those. And whether these scenarios address what I'm talking about or not, I really have to give it a little more thought.

MR. KRAMSKAYA: If possible, could this issue be addressed in the post-technical conference comments?

MR. HOUSMAN: I will certainly do that, yes.

MS. KRAMSKAYA: Thank you.

MR. MEAD: Seth.

MR. PARKER: I've heard a number of unsupported comments and claims by various panel members which I've responded to. But I have to take issue, Jonathan, with your comment that New York UCAP prices have not become less volatile since the introduction of the slope demand curve in the spot market.

MR. WALLACH: That's not what I said, by the way. For the rest of the state.

MR. PARKER: Sorry?

MR. WALLACH: That's not what I said. For the rest of state market.

MR. PARKER: So you were just referring to New

York City and Long Island?

MR. WALLACH: I said New York City because that's what I know most about. I'm assuming Long Island also. It had no impact on prices, on price stability or price volatility because the price has always been very stable. Unfortunately it's just been stable at the price cap.

MR. PARKER: Okay, if you want to back into that corner perhaps you may be right on that narrow ground. But the fact is in New York UCAP prices have become less volatile, more stable over the long term since the introduction of a slope demand curve.

There may be an exception to that rule but by and large the facts are there. They've had the slope demand curve in effect for three years now and I think it has by and large proven out its design feature and has had its demonstrated effect.

MR. WALLACH: And the point I was making is that it's more stable than what they had before, which was an extremely unstable monthly construct. And that if you have a different construct, for example, an annual auction as opposed to monthly auction you might not see the same kind of results when you go from an annual without demand curve to an annual with demand curve. That's the only point I was making.

MR. MEAD: Jonathan, am I understanding you correctly that in New York, in the rest of state area you would agree with Seth that the monthly New York capacity prices have become more stable since the introduction of the demand curve. What you quarrel with is the relevance of that in a four year ahead auction.

MR. WALLACH: That's basically the point I was trying to make. Unfortunately, less eloquently.

MR. MCPHERSON: One follow up question. Is there any evidence in New York that since they introduced the slope demand curve that there's been any decline in the energy prices as a direct result of the introduction of the slope demand curve?

MR. WALLACH: I haven't seen that and I haven't seen anybody who has argued that. And I think there's a good reason for that which is that to the extent that the demand curve encourages and promotes entry by peak and capacity the impact will be on reducing scarcity prices, not overall energy prices.

MR. HOBBS: We have suffered the natural gas prices increases so there is some confounding things.

If I remember the last filing that I read of theirs -- this is hearsay so I probably shouldn't be repeated this -- they said it was too early to assess whether they're getting the entry. They have to look at least five or six years to see if they're getting the amount of entry that they'd hoped to. And that's when you'd start seeing some price impact, if at all.

What we could probably see, it's too early to say.

MR. PARKER: On the other hand, I'm not aware of any requests for RMR contracts in New York. And that's a very positive sign, given what's been going on in New England and PJM.

MR. WALLACH: Well, I don't know that there was much of a movement or a push for RMR contracts before the demand curve either in New York.

MR. MEAD: Any other questions from Staff?

(No response.)

MR. MEAD: Let's take a break and come back at five after 3:00.

(Recess.)

MR. MEAD: Can you all take your seats, please? Can we take our seats, please? We'd like to get started again.

Okay. Before we begin, I anticipate that Staff's questions will finish before 5:00 and, if there are any individuals in the audience that have some questions, we will save some time at the end of the day to allow you to ask your questions and at that point I would ask you to confine your questions to the topics that have been announced for today.

Let's move on to the next topic, which deals with what slope or slopes would be appropriate for the demand curve. Let me begin asking a question of Andy Ott. As I understand it, PJM's recommended demand curve remains -- starting at the vertical axis remains flat at a maximum price of two times cost of new entry until the capacity level is 3 percent below IRM, and then it slopes down until it reaches a price of the net cost of new entry at a capacity level that's 1 percent above IRM. And by my calculation, that means we have a negative slope of 25 percent of CONE for every 1 percent increase in capacity relative to IRM. But then once you reach CONE at 1 percent above IRM then there's a kink.

If there weren't a kink and you continued that slope straight down, the curve would cross the horizontal axis at 5 percent above IRM, which turns out to be the capacity level at which the PJM curve does cross the horizontal axis. But your curve has a kink.

I have a couple of questions. First of all, what is the slope for that right-hand part of the curve and what is the advantage of -- and why did you choose that slope?

MR. ANDREW OTT: Numerically I'm not sure if I calculated what the slope is, but essentially I think -- and Ben correct me if I go astray here, because there were so many slopes I'm not sure I have immediate recollection -- but it went from 16 percent, I think the trajectory took it out to IRM plus 10 where it would have I believe crossed zero. Is that true?

VOICE: It's actually a bit more than that.

MR. ANDREW OTT: Okay. I'm sorry. The trajectory took it from IRM plus 1 to IRM plus 14; in other words, the slope was drawn as a gentle slope between those points. So it would start at the CONE at IRM plus 1, finish at zero at IRM plus 14.

And the reason we went with a more gentle slope there as opposed to the steeper slope which would have been on the other side was again to try to create less of -- to keep it away from vertical more, to make it more -- again, the characteristic or the performance of that curve seemed to be better. We were concerned if we had the curve falling too quickly that, you know, any individual generator, for instance, an LDA, could swing the result more. So we didn't want to -- we wanted the characteristic again for less volatility.

We turned those curves over the Ben of course and at one time our curve dropped to zero, I believe, and went all the way out to zero and didn't fall at the IRM plus 5 percent point. And again that was to keep that general characteristic and reduce volatility.

What we found though in discussion with some of the stakeholders they said well could you look at a curve that dropped to zero vertically after you stayed at that point, and we did an analysis on that curve and found out it actually did perform similarly to the curve that extended out. In fact, we found --

MR. MEAD: I'm sorry, I've lost the sense of what two curves you're talking --

MR. ANDREW OTT: Okay. The curve -- I don't remember what they would be in Ben's tables, but essentially there was a curve -- the curve that we have labeled our preferred curve, which essentially goes from IRM plus 1 out and drops to zero, you know, vertically at IRM plus 5 or plus 6, instead of continuing on or instead of that trajectory would stay constant all the way out to IRM plus 14, so it's those two curves. So do you fall to zero at some point or do you continue out on the same slope.

It seemed those two curves, when Ben did the simulation to compare them, the one that drops to zero vertically seemed to form similarly and had a lower cost component, I believe, so we said that curve's okay.

MR. MEAD: That is -- if my calculations are correct, if you have an IRM that starts at, you know, wherever you started it, price of CONE at 1 percent above IRM and then you extended that to IRM plus 14 --

MR. ANDREW OTT: Right.

MR. MEAD: I thought it was going to be 10 percent, but it's a flatter slope than 10 percent.

MR. ANDREW OTT: It is.

MR. MEAD: But having that less than 10 percent slope extend out to 14 percent of capacity, versus having that slope just extend to 5 percent above IRM and then dropping it, that those two curves performed similarly with respect to customer costs, reliability -- I guess those are the two --

MR. ANDREW OTT: Well certainly reliability -- Ben, I would defer to you to read the numbers off, but the analysis we asked Ben to do was essentially again to compare the one that drops off to see, you know, if we had substantially lower performance, because obviously that's the metric. And again as we talked about this with stakeholders and having discussions, we were trying to reach less opposition, if you will, to some of these demand curve because of the obvious angst with them.

So we thought if we had one that dropped to zero at some point, kept the beneficial part of the curve and didn't compromise performance, we would certainly do that, and that's really the nature -- so the reason we had this basically three-slope curve -- well, actually, I guess you'd call it four, horizontal, you know, the 25 percent, the more gentle, and then the vertical -- we came to that essentially through discussions.

But again the point is the reason PJM has selected that curve is because the analysis shows that it performs favorably compared to the metrics as opposed to -- it was stakeholder consent, it was really more the analytics proved that, you know, it seems to work. The way we actually came about it was the way I described.

MR. HOBBS: If you want to see the curves, by the way, this would be on page 32 of my affidavit. All five of them are shown at once of the August one, page 32, figure 6. It drops to zero at 4.3 percent above 1.0, which is equivalent to being 5 percent above 115 percent.

MR. STODDARD: The results are summarized in Table 9 of Professor Hobbs' affidavit, page 56, I believe.

MR. MEAD: There are several questions. I guess probably the most controversial issue is the truncation. One issue is -- and I think Mr. Stoddard raised this in his written comments. Ben's analysis was with respect to the entire PJM area and, you know, if you get, you know, some lumpy investments, PJM nevertheless is so big that, you know, a lumpy generator by itself is not going to push you beyond IRM plus 5 percent. But if you have, you know, smaller LDAs is that still true? Might a lumpy investment push you above the 5 percent level, in which case you get the vertical problems.

MR. ANDREW OTT: Certainly it's true if the market gets smaller and you have a transmission-constrained area and you have a large generator, I guess, you know, the possibility that you could flop between I assume the CONE or some function of the CONE and zero which has the oscillatory behavior, which is what I assume he's talking about. That certainly could be true if you had a reasonably large generator and a reasonably small LDA.

But I think the other dynamic again goes back to what Mr. Wallach was saying was that if you actually look at the way the clearing works. When the supply curve shoots through that vertical portion, the price actually would get set on the supply curve so the oscillation that you'll see is between, you know, the CONE and whatever that, you know, supply/demand curve crossing point as opposed to zero.

And so it is a feature of -- in other words, the design, or at least the proposed design of the PJM demand curve is more to act as that -- in other words, there is a supply curve going there and there is an optimization run as opposed to just setting it at the demand curve all the time, so if there was another increment, you know, sort of the marginal price setting entity there would be the generator of the supply curve. So you wouldn't necessarily -- he is right about that, the feature. So there is that component that also gets rid of some of the oscillation.

MR. MEAD: But would you agree though -- I mean, for LDAs of that size, your truncation starts to produce the same kind of vertical problems with the --

MR. ANDREW OTT: On a lower scale, right, sure.

MR. WALLACH: Can I say something about that? This is a four-year forward auction which, if I understand the RPM proposal in detail, that a new entry will be able -- a project which clears as a new entry four years from today will also be considered by PJM to be new entry for the next three years' worth of auctions and that it's not considered to be existing until you actually hit the delivery year. So the auction and the delivery year for four years forward is when you might start to see that sort of oscillation.

The other thing is that I understand from the latest --

MR. MEAD: I'm sorry, I'm not sure I understand that point. I mean, whether or not you -- the marginal supplier is new, you're still intersecting or may intersect the curve at the vertical point. And if you think that's a problem -- I mean, if you think vertical curves are a problem, then --

MR. WALLACH: All I'm saying is that if it clears in the first year -- if it comes in and it clears as a new entry in the first year, it will continue to do so for three more years' worth of baseline auctions. So this kind of swamping the market where, you know, it comes in and maybe gets a year, you know, of a price at new entry and then it swamped the market and you've got this cliff situation I don't think applies in the RPM structure. Maybe Andy, you know, if I'm wrong about that can correct me.

And let me just add the second point which is I understand from PJM's brief for the paper hearings they're not also saying for purposes of mitigation that for new entry in small areas they're actually going to guarantee its new entry clearing price for four years once it enters the market, once it becomes a project.

MR. ANDREW OTT: If it's needed.

MR. WALLACH: I think you're getting an awful lot of stability regardless of where that vertical piece is or whether you have a vertical piece.

MR. MEAD: How about Mr. Picardi and then Mr. Stoddard.

MR. PICARDI: I did want to agree -- when I made the comments earlier, he's right, you don't fall off the cliff to zero. When you look at what happened, though, you have to consider when you do get that vertical piece especially at the end of the curve, well how is bidding behavior going to react to that. And what's going to happen is -- I mean, the only thing I can think of is maybe the airline industry where generators are going to be forced to bid so low or not interested at all just to be there because you're going to have to hit the curve to try to -- I guess to try to clear and get selected. And I think that's a potential result even though -- so it may not be zero, but it's going to be awful darn low and that vertical element that you appropriately recognized, the concern you have, is still there because you're left with that choice, are not offering anything at all and then, you know, having the market power potential problem that we're dealing with, our withholding problem.

So I still think while maybe the cliff isn't zero it's practically zero and that that problem still needs to be addressed. And one of the things that we thought would be useful to address that problem is if Professor Hobbs could -- if they did a run where it would look like their original curve that their -- one of the ones they had originally talked about where they took essentially the same shape only just took it out at IRM plus 10 percent. They did -- one analysis we could find in the material of the cost/benefits of doing that, I would assume if the logic holds and you took it out another 5 percent, there would still be consumer savings in the energy and capacity market and you get 1 more percent reliability, I think. That was part of the filing.

MR. HOBBS: So although I haven't done a full suite of sensitivity analyses of that particular case where you run the tail all the way out to 14 percent, there are cases three and four on table 9 on page 57 of the August affidavit where, instead of dropping to zero at IRM plus 5 percent, drop it off at 10 percent and then 14 percent. Those numbers can be contrasted to the numbers in table 1, which are on page 36.

So we get -- instead of 98, you get 99 percent reliability and consumer costs are, at least at two significant digits, about the same. At least given the PJM-wide footprint, I wasn't getting any difference. But that's only under the base case behavioral and other assumptions; I didn't do the full suite of sensitivity analyses on the case where I ran the tail out to 14 percent.

MR. PICARDI: The other comment that we made that kind of was directed at that is you look at the transition mechanism and again we think what could potentially happen if you have a situation where you're applying it for the first time you do the auction to a larger suite of -- or broader-defined LDAs and then focus in on the narrow ones, you could have a situation at least where we are where we could actually see a situation where in one year the price goes down and then the price goes up and our view is that at least the representation through a transition, if there is one, should be in the same direction and that's not sending an accurate signal -- or maybe it takes you over to the paper hearing issue as to how you define the LDAs. I think they cross over here.

And one of the points we wanted to make is if there's a transition, which we're not recommending -- and why PJM did it -- but we would prefer to see it go straight to the model that they recommended as the final state with the 10 percent, IRM plus 10 percent. And we think they'll end up pretty much the same thing to costs to consumer-wise, slightly better reliability and people that are in regions that are generators will still be able to get some revenues in regions where they're providing value but there is some excess supply beyond the IRM.

MR. MEAD: Bob?

MR. STODDARD: Three points, and let me try to make them briefly.

First, I'd like to clarify with PJM the concept that a new entrant, that is to say someone who first got a commitment in one year, would be treated as new for auctions all the way until he reaches commercial operation. So even though he's earned commitments, he retains the ability to bid in an unmitigated way. That may ameliorate some of the issues.

MR. ANDREW OTT: Just for the record, the answer is yes, the mitigation would only kick in once they actually become commercial.

MR. STODDARD: Thank you. Second point, there are a lot of smart people who are familiar with capacity markets around here. But when you take these to Wall Street and talk about this, they look at these curves and they say you can go to zero, and I know this because I've talked to a lot of people about the New England curve and saying well how do we assure that this price isn't just going to zero immediately, how can we have any confidence to invest?

Having a vertical segment where, in a very plausible range of capacity, at least it looks like the market design can throw off a zero price scares Wall Street. And that has a price. And it has a real price in terms of the financing and terms these people can offer. That's based on direct conversations with investment bankers.

Third, we've heard a number of times how -- well, John has raised that New England has this vertical curve and that -- we can get stable prices under that. As my testimony on that to the Commission points out, we did a lot of pieces in that market design to keep price stability on a vertical demand curve. It was very hard. There are at least 10 major elements of the New England FCM that are there solely to compensate for the lack of a demand curve.

In my view, the demand curve that PJM has proposed here is a much more elegant system, at one stroke cutting through all of those 10 major issues and allowing, with one mechanism that can be calibrated and developed over time to address the need for price stability and accurate prices in the market.

MR. MEAD: Jonathan.

MR. WALLACH: Actually, if you take it to Wall Street, what I hear them saying is what the heck are you doing talking about demand curves and one year options four years in the future, what we want is long-term contracts for someone to off-take on our risk. That's what they want

MR. STODDARD: I've talked to different bankers.

MR. WALLACH: Well, I'm thinking of testimony before in another tech conference where we had investment bankers here saying those very things to FERC, to the Commission.

MR. MEAD: Seth.

MR. PARKER: If I could just add, the objective of a demand curve mechanism, whether it's here or New York, is not to guarantee a stream of revenues and make sure that generation will be built based solely on those market revenues, but to send a price signal. There's nothing, as far as I understand, in this mechanism or in New York that prevents bilateral contracts from being sold. So the fact is when you sent out an accurate and stable over time price signal, it facilitates all sorts of transactions that are beneficial to the market in general and to ratepayers.

MR. MEAD: Let me ask a question of Ben. In your simulation -- or do you know, in your simulation with the preferred curve, curve 4, do you know what percentage of the time the market cleared at capacity off the cliff, that is, beyond IRM plus 5?

MR. HOBBS: I would have to look at the detailed output, but based on the fact that the sensitivity analysis showed very little difference when I added the tail and didn't, I suspect it was extremely infrequently. But I would have to look at the output.

I do have the laptop right here. I could do that, if you wanted.

MR. ANDREW OTT: I mean, my recollection based on the results he had shown where we had the thing extending further was there were one or two years out of a hundred that we were even up in that range beyond 20. So that's one of the reasons we selected, we said it really doesn't seem to be clearing up there that much, it seemed there was a lot of investment activity, you know, around the button below the curve. But again his recollection is true that there were a few of them; the exact number we couldn't tell you.

MR. MEAD: That would seem to suggest, at least in terms of the model, it doesn't matter whether you truncate or not because --

MR. ANDREW OTT: Right.

MR. MEAD: -- but then the issue is suppose it does matter.

MR. ANDREW OTT: And again, I mean, that's on the full-size market and there was the issue of the smaller -- and certainly there is, when you get into the smaller LDAs, as I said earlier, the truncation may matter more and certainly I would indicate that.

MR. MEAD: Do you or Bob or anybody else have any sense of if we go to 23 LDAs, I think that's the number, how many of them are likely to be small enough where this is an issue?

MR. ANDREW OTT: I could not answer that on the fly.

MR. MEAD: If you could provide some information in the postconference comments, that would be helpful.

MR. ANDREW OTT: We can provide some post-hearing comments on that.

MR. MEAD: Jonathan?

MR. WALLACH: Just for the sake of moving this along--

(Laughter.)

MR. STODDARD: Just as an indicative number, we'll give you real numbers in post-hearing but a minimum efficient scale of a cc these days is about 500 megawatts. That is a very common new resource in this market. Well that means that you have to have an LDA that's 10,000 megawatts or larger for that 500 megawatts not to be a full 5 percent. So as a benchmark we can sort of say well 10,000 is something like the smallest allowable LDA and I'm relatively certain that perhaps a quarter of the LDAs on that list are below 10,000.

But some of them, of course -- I mean, the definition of the 23 may not always be relevant, the question is what the relevant market area is given the actual transmission constraints, which is yet a big unknown.

MR. WALLACH: And again my response to all that would be that if you've got an LDA where it's so small that 500 megawatts would create that problem, then that's too small an LDA to model and that you should be taking other steps to tie in that LDA and resolve the deliverability issues into that LDA so that it becomes part of a broader competitive market.

MR. MEAD: Seth.

MR. PARKER: I would just add that this consideration of a minimum LDA size to avoid that kind of price behavior is a valid concern. In New York it should be kept in mind that for the state as a whole that zero crossing point is 12 percent above what we are calling here the IRM but for the locational deliverability areas, New York City and Long Island, because of this very reason that slope is lengthened to 18 percent. So it's another way to address that same kind of concern.

And I also want to, on a related matter, chime in on the side of not supporting that vertical demand segment for all the reasons that have already been enunciated.

MR. MEAD: Coming back to some discussion we had before the break, Jonathan, as I recall, your recommended curve in your written comments truncated at IRM plus 1 percent. And as I recall, you drew the conclusion that with that curve using Ben's model capacity would be less than IRM only 2 percent of the time. Have I got my numbers --

MR. WALLACH: That's correct when using what I would consider to be more realistic assumptions about bidding practices.

MR. MEAD: I see.

MR. WALLACH: In that case, the PJM curve actually is at or above IRM 100 percent of the time.

MR. MEAD: I see. Can you tick off what you consider to be the more realistic assumptions that would lead you to draw the 2 percent?

MR. WALLACH: What I used was a sensitivity that Ben actually modeled in his original affidavit, which is that it assumes that existing capacity bids at $20 a KW year and new capacity bids at $44 a KW year.

MR. MEAD: Okay.

MR. HOBBS: That was the extreme of the range of bidding behavior I looked at. And again, I mean--

MR. WALLACH: Extremity is in the eyes of the beholder.

MR. ANDREW OTT: Again, if you're sitting there, we have a cliff and you have a supply curve going out as I think it was Matt may have said, the behavior of the generators to say well, you know, $10 is better than zero, meaning I get nothing if I'm beyond -- if my offer is out beyond where the vertical curve comes down I get nothing, so I need to bid under to get the -- so the behavior of the generators will be such that they're going to want to try to compete with -- you know, a competitive market, you know, is actually a good thing.

So the assumption that the bidding behavior will sustain at some high level and those generators I assume will just go retire for a while until they're needed, I don't know that that -- and again, when we were validating Ben's assumptions and having discussions about them, we thought that that was again at the upper end of the range, although again it was something we modeled because we need to model the wide variety -- we had zero, we had $20,000 and then some stuff in between.

And I think -- again, I'd stress that when you're looking at these curves, because of the nature of the simulation and the nature of the uncertainty of the input data, you need to look at a variety of sensitivities and look at behavior over all those sensitivities to make the decision as opposed to just looking at one. Because anybody can pick their best set of assumptions and try to figure out what to do from that.

But I think only those that are robust over a wide variety of assumptions are the ones that we had used as a basis for our assessment.

MR. WALLACH: Let's just be clear that, as Bob pointed out much earlier this morning, that in a competitive market the benefits of having uniform price clearing in this auction is that it encourages bidders to bid at cost, not above and not below.

You don't want to bid below because if you clear, you've just put yourself in the red. And you don't bid above because that risks that you don't clear at all and you don't get anything. That's why you have uniform price clearing in this auction. That's why you pay everybody a single price.

So to say that well, you know, someone -- a vertical curve is going to create this incentive for someone to bid low is just contrary to the theory that is at the base of what we're doing here. And so again the use of -- when I used $20 say for existing capacity what I was looking at was PJM's data on supply costs, on the supply curve. And $20 is well within the range -- let me just finish, Andy -- $44 is actually low compared to what Ben's model uses. Remember I was talking earlier about it uses a value for the purposes of determining profitability, $44 is actually still below cost according to that model assumption.

The other thing is that even though it's more realistic, it's still not quite the reality of what's going to happen because in reality what you're going to see is a supply curve, not $20, $44. And so the volatility that you see coming out of the model with this and this in reality should be lower because it should be less volatile because what you've got is a smooth curve and so depending on where you are each year you're going to move a little bit up or down that smooth curve when you're crossing that vertical portion.

MR. MEAD: Ben, for the numbers underlying table 1, what did you assume new supply was bidding in at?

MR. HOBBS: So I assumed that new supply was bidding in at zero in table 1 and them performed sensitivity analyses on that in the subsequent tables. And then in my filing two weeks ago, I instead used 25K as a base case and did sensitivity analyses around that.

MR. MEAD: Why is it realistic to think that new capacity would bid in at zero rather than, you know, whatever CONE happens to be?

MR. HOBBS: I don't claim that any particular set of assumptions is the most realistic one. This was the starting point. But why wouldn't I have not bid CONE? The theory that Jonathan quotes that if you're a price taker the profit maximizing price to bid is your marginal cost is applicable to short-run energy markets. This is a commitment to build a plant and your short-run marginal cost, given that your building the plant, is awfully low. It's not 44 -- it's actually not determinable because you're spreading a fixed cost over 20 years. So for that reason I looked at a spectrum of possible bids between 0 and 44,000 to see how it would affect the rankings of the curves.

Remember the mode that the model should be used in is compare curves under a wide range of assumptions. Try not to pick out a single set of assumptions and say those are the assumptions and therefore this is better by so much. And so over the wide range of assumptions, curve 4 comes out better. I happened to choose for the base case the zero price, but I could have chosen anything and, in fact, two weeks ago I used 25K as the base price.

MR. MEAD: And so if you assume that new entrants bid higher, I gather that the result is that a given curve produces more reliability -- I'm not sure why that result follows, but -- Jonathan --

MR. HOBBS: We could go through the tables. I believe that that's the case.

MR. WALLACH: The reason --

MR. HOBBS: Somewhat more stability in prices and so the rank ordering of the curves in terms of relative performances is preserved but the differences then change and they all perform better.

MR. ANDREW OTT: Again I think it is also characteristic that that assumption is more -- the vertical curve is much more sensitive to that assumption of what the incumbents or existings bid than the slope curves. And in fact the slope curve, it drops -- that vertical part, you know, does have a little bit of sensitivity that the one that extends further out doesn't because it matters more what the existing or bidding because of that characteristic of the vertical.

MR. MEAD: I was thinking more in terms of what the new entrants bid. I guess I thought the theory was that since we're talking about four years out you're going to have new entrants who either haven't begun construction at all or have -- had so little commitment that most of their costs are still incremental and can be avoided if they're not chosen in the auction.

MR. WALLACH: That's exactly right. They should be bidding not their short-run marginal costs but long run.

They should be bidding in their full cost.

MR. HOBBS: But the full costs is ambiguous for all the reasons we discussed this morning, for example, whether you should levelize real terms or nominal and so forth. It's an allocation problem.

Oh, by the way, I should point out I did look at a single hundred-year simulation and for curve 4 it never went above the 5 percent threshold. It never fell off the cliff. Just for that one. It surely does in some others.

MR. MEAD: Yes, Bob?

MR. STODDARD: Just one final comment on this before we leave it. I realize the market monitoring is for they paper hearing but vertical segments do create issues of both monopoly and monopsny power in zones. And if you have a place where you know that the price can fall and relies on bidding to not fall, there can be incentives for LSEs to contract new generation to keep yourself in that surplus. The closer that vertical segment is to the axis -- for instance, in John's curve it's quite close, you don't have to have much of an overbuild or sustain much of an overbuild to keep prices potentially very low and the contracted generation need not bid high because it has a contract. So there are issues of market power that are directly linked to the shape of the curve.

I'll defer the full range of that discussion to the paper hearing, but the two cannot be separated, they're integrally linked, how much monitoring we need to do and what the shape of the curve is.

MR. WALLACH: I guess our perspective -- and here I'm saying CCRs perspective -- is that a, at least -- let me back up.

Market monitoring and mitigation will be required regardless of what curve you choose in small LDAs. So sure the incentive may be marginally greater if you've got a vertical portion, but it's not as if if you get rid of the vertical portion that you're getting rid of your market mitigation. So I don't see it as being particularly relevant to this discussion.

MR. MEAD: Okay. A question about the slope of the curve to the left of what is IRM plus 1 or whatever we pick CONE to be. Is there general support for that slope? Is it too steep? Is it too flat?

MR. STODDARD: My view is in the larger LDAs it's one of many perfectly good curves. In smaller LDAs, just as Seth told you earlier, I think the experience in New York is that it makes more sense in small LDAs to have a curve that has a shallower slope when thought about on a percentage basis.

The megawatt slope -- I mean, you did all your slopes in terms of percentages. If you translate that into a price effect on a megawatt basis, the LDA -- the curves become steeper and steeper in smaller and smaller LDAs. So it becomes appropriate in small LDAs, in order to mitigate the effect of adding a new unit or two on the price, even if it doesn't crash the price all the way, it still has a greater saw tooth pattern of new entry. So it's appropriate, as New York has done, to move the demand curves out in small LDAs.

MR. MEAD: I mean --

MR. STODDARD: This would be to -- when drawn on a percentage scale, to flatten the slopes of the curves, kicking them out so that the zero intercept would be farther at a higher percentage above IRM.

MR. MEAD: This is a zero crossing point?

MR. STODDARD: A zero crossing point and it would shift the curve collectively.

MR. MEAD: Actually my question had to do with the left-hand portion of the curve from the maximum price down to CONE.

MR. STODDARD: So the steepest section.

MR. MEAD: You can make that -- a couple ways you can make it flatter. I mean, one way would be to start dropping the price below the maximum price earlier, or I suppose another way would be to push the capacity at which the price equals CONE farther to the right.

MR. WALLACH: And there's a third way, which is that you can reduce the maximum price.

MR. MEAD: Yes, yes, that's true, too.

MR. WALLACH: And I know that we've got these two topics separated but I think, you know, they're really part and parcel of the same thing.

MR. CHOUEIKI: What I was going to say is we are doing right now sensitivity analyses ourselves in Ohio to assess all these slopes basically, not even thinking about only linear curves from the X axis going down but basically going convex or going concave on either side of the inflection point to see what's going to happen. And if we get these results, you know, we'll confirm them with Ben and then file them ourselves.

Because basically, you know, everyone -- we're hearing the people in the generation business saying what's in their best interest, but we have to look at the consumer side. We have to look at both of them. Remember, we have two objectives here, the objective of least cost to consumers and incent investment, too, after you've covered reliability.

So I wouldn't want to, you know, whatever they wanted to go slower on the right side because then that would incent more investments, but we want to look at the consumer side.

So what we are planning to do in Ohio is run all these analyses and not be limited to specific demand curves that were, you know, specified by PJM; but rather do our own curves ourselves and see what the results would look like.

MR. MEAD: Yes, Seth.

MR. PARKER: We found that the curves, as long as they are not too steep and not too shallow, would be fine. Which is to say, the two sloped portions of the curve are fine. Again we take issue with the one vertical segment.

But I would also point you to an analysis that we did in New York in our report published for the New York ISO in August of 2004 where we tested the incentives for economic and physical withholding at various points on the New York curve, and also tested various sized portfolios to see if there was a withholding incentive. Which is to say, if there was an incentive to say withhold 5 percent of your portfolio in return for a rise in prices greater than 5 percent, that would be a bad thing. And I think that is the kind of test that could be undertaken.

We haven't done it. We don't intend to do it. But if one of the parties wanted to, I think it would be very revealing.

MR. HOUSMAN: If I may just comment on that, I think that is a good idea. However, it would have to be done on the LDA level, and that is really what you need to look at. Because I saw in somebody's preconference comments a comment about how you would need to withhold a huge amount of capacity in PJM. But of course that might be what shows up in a system-wide model but not in small LDAs.

And our concern I think is that a steep curve going to a high price only increases the incentive for withholding in those LDAs very quickly.

MR. MEAD: Let's go to the maximum price issue. Am I right that under the current vertical curve the deficiency charge is some estimate of CONE, except if the--I seem to recall that at at least some point in PJM's history, and perhaps I have it wrong, that if the region as a whole had less capacity than IRM, then the deficiency charge doubled.

MR. ANDREW OTT: You mean under today's market?

MR. MEAD: Yes.

MR. ANDREW OTT: Yes, that is true. Under today's market if we are within a certain amount of the IRM, we would escalate the penalty or deficiency rate over time. And that is true. I think in the past we have actually seen that go up. Obviously, again the state of today's market obviously on a market-wide level we have enough capacity. The issue is locational and some other issues.

MR. MEAD: Right. Okay.

MR. MEAD: Okay, I mean the general I would like to pose is: Is PJM's proposal for 2 x CONE the right maximum price? It seems to be consistent with the current vertical curve, but on the other hand as I calculate the slope under the proposed curve, if you started to go below--the price at IRM is 1.25 x CONE. And so if you start to drop below that, the deficiency charge, or in effect the deficiency charge, is lower at least for awhile than it is currently. Because today if you drop below IRM at all and somebody is deficient, they start paying 2 x CONE.

We have heard arguments that one benefit to lowering the maximum price is that it flattens the slope. But there is that issue, and then there is the issue of if the market finds itself less than CONE is 1.25 x CONE, or whatever, enough incentive to induce additional investment?

Jonathan?

MR. WALLACH: This, actually I'm a little confused. I guess my recollection was that when PJM, when we went from daily penalty to seasonal that the seasonal did not include the two-times factor. Maybe this is just something I need to check.

But the more general point is that I think as you are talking about a longer period, and now we're talking about at least RPM, it is a year-long commitment and therefore a penalty for a year, then you should be thinking about lowering the penalty rate maximum value below what you used for a daily market.

MR. ANDREW OTT: Well I'm not sure under RPM that the penalty is annual. I believe, if you actually look, if you fall below your targets I think it still assesses it as a daily deficiency charge until you correct it.

I mean there may be times when there's an annual penalty under certain circumstances, but I think if you actually look at the rules, if an entity would fall below for a brief period for whatever reason, they would just pay the deficiency during that period.

MR. WALLACH: I guess I wasn't thinking of it so much as a penalty as what you think about what's the appropriate scarcity price to pay, given that you're talking about a year's worth of commitment and therefore a year's worth of, you know, payments at that level. And so therefore two times--the fact that you have two times, or you did have two times for a daily market may not necessarily be the appropriate comparison when you're talking about an annual market.

MR. MEAD: Bob?

MR. STODDARD: Two comments. First, the demand curve, all the parameters have to work together. So we have to recognize that if you decided that if instead of two you want to have 1.5, then in order to get the same level of reliability that the curve PJM has proposed, you have to make substantive changes on the X axis.

There are other parameters you could change, but the whole thing has to be re-evaluated. It's not possible to move one parameter at a time.

The second issue is something I raised earlier this morning and I'll return to it, that I note that Ray's and Seth's estimate of the cost of New Entry differ by more than a factor of two. So that even with the two-times factor we have in the curve now, if we built it around Ray's curve we don't get new capacity coming in if Seth is right.

The tighter we run that cap down, if it's only one-and-a-half times, we now have to have that much more confidence in whatever estimate of CONE we are using in the market. Perhaps we can gain that confidence over time, but at least as an initial point I think we have seen that there is a lack of confidence about what exactly the market will need to participate in the RPM Auction.

MR. MEAD: Ben.

MR. HOBBS: Dave--go ahead.

MR. CHOUEIKI: No, you had it before me.

MR. HOBBS: Okay. I just had some sensitivity analyses that were relevant to the question of how high, and also that slope. And these are Sensitivity Analyses 1 and 2 on any of these tables, but we can look at Table 9 on page 57 of the August Affidavit.

It turns out that, because the system most of the time is to the right of IRM, that the slope to the left doesn't really matter very much. So we see that there is really not much deterioration in performance if you do lower that maximum amount or change that slope. There's some deterioration, but the deterioration is small relative to the differences between the different curves.

MR. MEAD: Okay, thanks.

MR. CHOUEIKI: Mine was more of a question to PJM. We started, at one point in time I thought it was 1.5. Why did it go up to 2? Or has it always been 2? I mean, in New York it is 1.5, right? In New York?

MR. PARKER: Correct.

MR. CHOUEIKI: So why is it 2 here?

MR. ANDREW OTT: Yes. I don't believe we started--if you're asking--

MR. CHOUEIKI: I think it was like in Ben's paper maybe, that IEEE two-column paper. The numbers were 1.5.

MR. HOBBS: I have the paper here, I can find it.

MR. ANDREW OTT: Well, but anyway--

MR. HOBBS: I think the proposal was always 2.

If it was 1.5, that was my--

MR. CHOUEIKI: I mean, I could be wrong, too.

MR. ANDREW OTT: We may have had a sensitivity at that range, but really the target for deficiency, again based on the historic methodology, and again to some extent on Ben's simulation, showing--although he's right, it may not have as significant an effect as you lower that deficiency rate to the left, you do see deteriorating performance. Again, it may not be as significant as some other changes you make, but you do see it.

And again, the issue that--again, although all this stuff again gets reviewed every three years, and there is this reassessment, again the cost if you are wrong, the downside of being wrong--and that's one reason why we used a two-times deficiency rate in the past when you started to get short because the price of reliability, we really can't compromise those requirements. But we have those obligations both on the regional level and national level.

MR. CHOUEIKI: Is it mostly to incent generation? I mean, because in New York--

MR. ANDREW OTT: Well it's also to incent load to respond. I mean, essentially if a load customer is facing the worst-case scenario for the load customer to pay is 1 x CONE versus 2 x CONE, then again this goes back to things we were talking about this morning.

I mean, the load customer can take their own action, whether that be a bilateral relationship with a generator, or to build one themselves. But at some point it becomes a critical need to do it, and that is why you have this escalating cost when you go short, because the shortage cannot be sustained. It simply is unacceptable to have a shortage.

So to say you're going to set that at a constant 1 times the cost of new entry doesn't reflect that. It doesn't reflect that as you go shorter and shorter you have more and more problems from a reliability perspective.

And again, I would say obviously if you go to the extreme and say, okay, I'm down to levels where I'm going to actually start to effect operations, then the cost of that in terms of risk of blackout is immense.

Now again, we as an industry can't seem to quantify it, but certainly we can quantify--we can rationally describe that as we get shorter and shorter we should escalate to penalties because it has to show that effect.

MR. CHOUEIKI: Okay, but if we have again a working model in New York--I don't know for how long they've been using it, if it's been three years now, and it's 1.5 times, why do we need to go to 2? I mean, that's just a question that we have a demand curve that's working, presumably. In New York I think they have three LDAs? I think they have Upper State?

MR. PARKER: Yes.

MR. CHOUEIKI: So--and I presume they have three different CONEs, but it's times 1.5. And just out of curiosity I was thinking why do we need "2"?

MR. PARKER: I might just point out that in New York all sorts of demand curve parameters are different. It's not just the maximum price. And again, if you want to think about changing any one part of it, you may end up having to change many other parts.

MR. CHOUEIKI: Oh, you mean the IRM there is higher than 15 percent?

MR. PARKER: The IRM. It's a single segment curve that goes all the way down to zero in one continuous slope. So you may be right on the deficiency price, but again that is only one of many things that are different.

MR. ANDREW OTT: I don't know, did it have a right shift also?

MR. WALLACH: Actually, it does not. In fact, they have CONE at IRM, or their version of IRM, and 1.5 times is the penalty.

MR. MEAD: Ezra?

MR. HOUSMAN: Well I just find it interesting that not only do we have the only empirical evidence we have is that 1.5 times CONE is enough, but even Professor Hobbs' model indicates the 1.5 performs just as well. So I'm just curious what the evidence is that would support a higher level. And I would say that, from a consumers' perspective, as Andy points out, the issue is what if you're wrong?

And if we end up in that area because we've designed the market in a way that shows no particular benefits of going to 2 times CONE instead of 1.5 times CONE, but if we do in fact end up in a situation where we fall shorter of capacity, then it's going to be enormously expensive to consumers.

So given that an analysis shows that 1.5 is just as good, I am just curious why we ended up--and what economic theory there is behind going to twice CONE. It seems like an arbitrary number, instead of 1.5, which is another arbitrary number.

MS. KRAMSKAYA: And what is the role of the Backstop Reliability Auctions here?

MR. ANDREW OTT: The role of the Backstop, again, is if we have a persistent shortage. And again that is part of the reason to have, again, these escalating deficiency rates to try to avoid that situation. But should we, for whatever reason, we're five times too low for CONE, so as we go through time we don't see investment, or whatever, the Backstop is essentially you say, if we have a deficiency for a year, we do an analysis to determine why. Is there a barrier to entry? Is there a need to change the CONE, or some of these parameters? And we would make those changes, if necessary.

But if that deficiency persists for four years in a row, then there needs to be intervention. And obviously that intervention would have to be filed with the Commission. All that stuff is in there. But the Backstop is essentially to say, well, if the worst should happen, and for whatever reason there is an area of the system where we would have--now do I think that is likely to happen, given all the protections? Probably not. But again it would be imprudent for us to offer a model that did not resolve any possibility, however remote it may be.

MS. KRAMSKAYA: Would that allow you to lower that coefficient--

MR. ANDREW OTT: I don't believe it would allow us to lower that.

MS. KRAMSKAYA: --to, I don't know, 1.5, 1.8?

MR. ANDREW OTT: No, I don't honestly believe it would allow us to lower it. Because, again, the Backstop is supposed to be a last resort. The market should be designed to do the response on its own.

MR. CHOUEIKI: I have a follow-up on this. With respect to the Backstop, who would be the one who would purchase the contract for capacity? PJM, or a third party?

MR. ANDREW OTT: Under that mechanism, PJM would file with the Commission that we want to hold the Backstop Auction, and PJM would hold it on behalf of them.

MR. CHOUEIKI: So PJM would be the one who signs the contract, buys the capacity, and then charges them whatever--

MR. ANDREW OTT: We would provide a guarantee to that generator for a certain number of years, and that would be funded by the load-serving entities, yes.

MR. CHOUEIKI: Why wouldn't, for example, an independent party? You would file it with FERC. Have an independent--since you're administering the grid, you also want to be the one who administers the contract--

MR. ANDREW OTT: Well my goal of course is to get the thing done. I honestly don't care--

MR. CHOUEIKI: Who does it?

MR. ANDREW OTT: --you know, who--I mean, I would--again, this whole process of the RPM Auction contemplates that this will incent LSEs independently to go out and do long-term contracting that they are not doing today. It will also incent longer term demand/response investment to happen. So it is our hope that that all gets done before we ever get to any of these type Backstops.

MR. MEAD: Seth.

MR. PARKER: I have a question. And that is: I think the Backstop Rules as proposed refer to a "Baseload Plant"? Is there a reason for limiting that new resource to being Baseload?

MR. ANDREW OTT: Well there were two different--I thought there were two different types of backstop triggers. You know, one had to do with a total shortage, a system shortage. And again I stress that the backstop--I think sometimes this gets confused, so I think we need to make sure what we are talking about.

The Backstop is talking about a System-wide or a market-wide shortage. You know, should we have a shortage in an area of the system, of course you do a transmission upgrade if you have a reliability violation because you have excess generation elsewhere.

So obviously I wouldn't need to do an intervention in the capacity market if I can solve the problem with transmission. But, you know, if we have a Region-wide shortage of capacity, then you would trigger this Backstop against--assuming in the rare event, or unlikely event, it would sustain for four years. But there was also a mechanism involving, you know, lack of baseload capacity that was also part of that trigger, which is what I think you are referring to, but this was more system-wide.

MR. MEAD: Yes, Bob.

MR. PARKER: Just a quick comment. Ezra was saying, well, the only empirical evidence is to have a 1.5. The full range of empirical evidence is to have a 1.5 coupled with an estimate of the cost of new entry, which is more along the lines of $7 a month, and not along the lines that PJM has proposed.

So I think if we take those as balancing parameters, that would be a potentially reasonable outcome. I'm very concerned about using both a low estimate compared to everything else the Commission has accepted for the cost of new entry and a very low cap on the outcome. And those two together strike me as being not conservative.

MR. MEAD: Before we throw--or give the audience an opportunity to ask questions, I have a couple of questions. And I see Seth has a comment.

I have a couple of questions for Ben that are really probably more applicable to tomorrow's discussion, but since he is not going to be here tomorrow I understand this is my last chance.

The first question is: In your simulations, as I looked at the graph, the graphs of your simulations for your Curve 4, the issue was what was the average length of time for a business cycle. It looked like it was about 10 years, but--

MR. HOBBS: This is on page, let's see, not 42.

Sorry, Dave, if you could help me.

MR. MEAD: Let's see, I--

MR. HOBBS: Ah, that looks promising. Page 38, Ezra suggests. Yes. Okay. We see these are reserved IRM ratios for two different curves. Is this what you were referring to?

MR. MEAD: Yes. Is it fair to characterize the preferred--PJM's recommended curve is the thick curve?

MR. HOBBS: Yes.

MR. MEAD: And it looks to me like it cycles about every 10 years.

MR. HOBBS: So let's count the peaks. One, two, three, four, five, six, seven, eight, nine, ten, eleven, twelve peaks in a hundred years. Eight years, say.

MR. MEAD: All right. I guess the next question is: Again for the recommended curve, what percentage of time did capacity meet or exceed IRM plus 3 percent?

MR. HOBBS: IRM plus 3 percent?

MR. MEAD: If you don't know right now--

MR. HOBBS: That's something that we could calculate--

MR. MEAD: --you could give us that information for the record.

MR. HOBBS: Hisham asked us for all the information, so maybe he has it offhand.

MR. CHOUEIKI: What was the question? I'm sorry?

MR. HOBBS: That wasn't fair.

(Laughter.)

MR. HOBBS: I was lateralling the question to you. We just need to get--we have all the years, and we can compile a distribution of it and answer that question. I don't know what it is, offhand.

MR. MEAD: If it's possible to have it available for tomorrow, that would be nice. But if not, then if you could submit it in your post-conference comments--

MR. HOBBS: Okay.

MR. ANDREW OTT: Okay, so the percentage of time--the percentage of the hundred years where we have an excess above 3 percent?

MR. MEAD: Yes.

MR. ANDREW OTT: So it is IRM plus 3, above IRM plus 3.

MR. MEAD: Right.

MR. ANDREW OTT: Okay, we will--

MR. HOBBS: I would just be curious, that 3 percent number, its significance is what?

MR. MEAD: Well the significance is that PJM's recommended opt-out proposal has calculated LSEs--

MR. HOBBS: Ah. All is clear.

MR. MEAD: Okay.

MR. ANDREW OTT: We will attempt to have that for tomorrow.

MR. MEAD: And the final question I had is with respect to the vertical curve, since the opt-out folks basically get a vertical curve.

As I understand it, in your simulations you assumed a two-times CONE deficiency charge, or a vertical--basically a two-times CONE deficiency charge. And with a vertical curve, and that maximum price, you get a situation where capacity exceeds IRM only 39 percent of the time.

MR. HOBBS: If that is what is in Table 1, then, yes.

MR. MEAD: I believe it is in Table 1.

MR. HOBBS: Yes. Okay?

MR. MEAD: And as I quickly looked over your simulations, I saw simulations that examined the vertical curve with lower deficiency charges but not higher deficiency charges. And I was wondering--the question would be: At IRM, what kind of deficiency charge would you need in order to get the result of capacity less than IRM at some small number, let us say 5 percent?

MR. HOBBS: This is not entirely unrelated to a question I think Jon poses, which is: How far would you have to shift the curve to the right until you get--the vertical curve to the right to get that same answer?

MR. MEAD: Actually, if I could ask for a couple of scenarios, you know, sort of different mixes of deficiency charges and vertical curves at IRM and above that gets the result of some small percentage of time, let's say 5 percent.

MR. WALLACH: David, I have to--I want to throw a word of caution in here in interpreting those results.

First of all, Ben should run those numbers over a range of assumptions about what people are bidding. But more importantly, if I understand the opt-out I don't think that simulating a vertical curve with the RPM is a simulation, a reasonable simulation, of what's going to happen for those participants who choose to opt out.

Because presumably they are going to be securing their capacity requirements through bilaterals probably longer term than the year commitment that you've got for the RPM Auction, and it is just a totally different dynamic.

And so I haven't really thought it through, and it is a very interesting concept to say, well, you know, sure we can model the opt-out by saying, you know, a vertical curve and see what happens, but I don't think that you're really capturing the dynamic of what is going on for the opt-out participants in that way.

That is assuming that what they're going to do when they opt out is go participate in some, you know, auction, one-year auction, and on the generator's side that's all they're going to get is a one-year commitment by someone to pay them some amount of money.

And again, I think if you talked to the opt-out people they would say, well--which I'm agnostic on the opt-out issue. I'm not here tomorrow, but again I just don't think that that's what you're simulating. You're not simulating the dynamic of the market participants who are opting out and engaging in bilateral transactions.

MR. MEAD: Okay, I didn't want to have this discussion today, but since Ben can't be here tomorrow I wanted to get that piece of information. Other parties are perfectly free to argue that his results are not relevant to those issues. And if anybody else has a different methodology for evaluating the effectiveness of incentives to keep opt-out people to honor the commitments, we are all ears.

MR. CHOUEIKI: I would like to caution also--I am not going to be here tomorrow, so I would second that caution just because, you're right, with an opt-out you don't have anymore auctions. You don't have investment behavior. In the sense of the auctions in RPM or under this model. So no matter what Ben's results show you--and ours, actually, even for a vertical demand curve shows you you can go up from 39 percent up to 78 percent, 79 percent just by changing investment, the risk versus risk neutral.

So definitely it's a completely different dynamics, and I would caution not to use any of these results for that type of an assessment for tomorrow.

MR. ANDREW OTT: With that being said, can I try to understand what he's asking for so I can supply it?

(Laughter.)

MR. ANDREW OTT: Could I just understand? I understood the periodicity one, and we certainly can follow up with that. I understood the RPM plus 3. But the last question was looking at I think the performance, you know, getting a higher performance level say comparable to the curve. How high do you need to put the deficiency rate and keep the vertical at IRM? That's one.

MR. MEAD: If your objective is--I mean, the result that your preferred curve has is--

MR. ANDREW OTT: Something comparable to that is what you're saying?

MR. MEAD: Two percent of the time you're below IRM, although there's some debate about whether that's exactly the right metric, but with a vertical curve, which is what opt-out customers are going to have.

MR. ANDREW OTT: Right.

MR. MEAD: That's what they're going to have with some incentives and penalties for failing to perform.

MR. ANDREW OTT: Right.

MR. MEAD: The question we need to have is how high do those incentive penalties have to be to be comfortable that they will have performance comparable to the result--

MR. ANDREW OTT: So the first question then is--

MR. MEAD: The deficiency curve--

MR. ANDREW OTT: --the height of the deficiency curve--

MR. ANDREW OTT: And then another--

MR. MEAD: Or, or, you know if you move the requirement to be IRM plus 1 percent, what does the penalty have to be?

MR. ANDREW OTT: We'll do some analysis. If we can have that for tomorrow, we will. I will chat with these guys about whether we can.

MR. MEAD: And again, you know, other parties are free to comment on whether this is relevant, or useful, and whether there are other analyses that would shed better light.

MR. HOBBS: Tomorrow?

MR. MEAD: Tomorrow, yes.

MR. ANDREW OTT: Yes, I'm looking just to understand your question at this hearing. Thank you.

MR. MEAD: Okay. Anna, we were going to throw it open to comments, unless there are some other questions first that staff wanted to ask.

MS. COCHRANE: Bob, you have your name tag up. Did you want to--

MR. STODDARD: No.

MS. COCHRANE: Okay. Is there anyone from the audience that has a comment? If you can come on up to the mike and remember to state your name and who you are with.

MR. PAKELL: Hi, I'm Gregg Pakell. I'm from DTE Energy Trading. I just have I think what is a clarifying question that kind of occurred to me when we were discussing this kind of, you know, this drop off on the demand curve where if you reach, I guess if it's IRM plus say 5 or 6 percent, all of a sudden the price goes to zero.

The question is: If you've got individual demand curves for LDAs, and let's say you've got a 500 megawatt combined cycle or something like that that all of a sudden in and of itself just causes that curve to drop off, and I guess my sense though is if the rest of the market is still at IRM plus 3 percent or 4 percent or whatever, wouldn't it be the case that that unit would be deliverable into the rest of the market LDA? And wouldn't it then be eligible for the market price on their demand curve?

MR. ANDREW OTT: Yes. Certainly, and again that would limit the volatility of the answer, absolutely. So essentially the LDA would become unconstrained and the price would essentially fall.

You would still have the oscillation between whatever the price was and the market reference. And I already said it won't be zero, it will be some reference point.

MR. STODDARD: If I could pick up on that. To the extent there's actually a differential cost of being in the load pocket as opposed to being in a general pool--and that's presumably why it's a load pocket; it is harder to build there, it's more expensive--that differential can only be recovered then in years when the pocket is separated.

So there will be a greater concentration of cost recovery, so that will add yet again to the volatility of prices.

MR. SHANKER: Roy Shanker. I'm presenting comments tomorrow on behalf of Five Stakeholders, but these comments are essentially my own.

I think as Staff and the Commission considers the issues that went forward today, I had three general comments that I would like you to--I would hope you would focus on in terms of the property of demand curves as a whole, or variable resource requirement curves.

The first is the recognition that steadystate when you're selecting a curve in the design, the curve sets quantity not price. That's an overwhelming observation that you always have to keep in the back of your mind when you're setting a policy about this.

There is somewhere a correct or true price of new entry, a true CONE. And that gives us in the steadystate long-term world a horizontal supply curve. And so what happens is, that's the price. At least that would be the recurrent new price. And all that the demand curve is set quantity.

Once you make that recognition, you then should carry that through into a lot of the observations about the fighting that's going on about where we locate the curve, what's the cost of new entry.

The demand curve is basically a feedback loop. It's a control mechanism. It's--somebody said 15 percent, or 16 percent. And the curve is a tool to get investment to focus around that number. But there is a true number. So if PJM say $50 and Mr. Pasteris' number is $44 or $50, and Mr. Parker's is $85, and all the bids come in at $75, the right number is $75 regardless of what they have done, and regardless of what the estimated net cost of energy is, the net energy adjustment is.

So the focus shouldn't be on solving an institutional problem to fight this modeling forever. It ought to be on making sure that once we get at least a reasonable starting point to make the feedback mechanism work to get it started, that PJM focuses its attention on analyzing the new entry bids. Because there could be some bad bids.

But to the extent that we want to put efforts into this, we want to see legitimate bids setting the cost of new entry. And whatever that number is, that is the number that you ought to be focusing on determining and using for the updates for the curve. And so all this fighting analysis and fighting models hopefully becomes very irrelevant.

I think the last thing, which is a subtle point, going into the interaction of the LDA size and sort of the cliff issue on where it breaks off is that PJM has done a very good thing in its recent adjustment. And actually I thought it was five years in a small LDA. It's the first year plus four. It might have been commented at four, but I thought it was five.

If that is approved, and I think the criteria for when a new entrant sets price for an LDA, the duration is a key thing to be considered that I have not seen anywhere in this process, and maybe it can be part of this discussion. That five-year window though is key because steady-state the expansion, the RTEP, will pick up CETO/CTEL violations, which are the basic mechanical structure issue that causes the split with the rest of the pool, and solve them.

So you cannot have a duration presumably longer than five years, and I think it would actually be less than that, where a new entrant sets price in an LDA. Because after that period of time, the CETO/CTEL violation that was splitting it would be solved automatically out of the RTEP.

This is a little different than New York, and different from New England, in that the structural reasons for separation--there may be local prices that are different in terms of the marginal costs--but the new-entry mechanics of that separation are different here, and they are designed to go away.

So it is that package of recognitions. The curve sets quantity. That we get good information for new entry. And that ought to be with setting the curve in terms of the cost of new entry, not fighting these wars of analysis. And then understanding the detailed mechanisms of the price separation and what is happening with respect to the shape of the curve drop off all go together. And I think what it does is that if you look at that in resolving this you get something close to what PJM is recommending here. And with a focus on fixing the curve for new entrants based on their bids as being the primary adjustment mechanism as opposed to the studies.

MR. WALLACH: I guess my only comment in response to that is that I agree with Roy that the demand curve essentially sets quantity. However, there can be--that assumes that you're in the long run with a horizontal supply curve cost of new entry.

There can be instances both in the short term, and even in the longer term in small LDAs if you have whatever barriers to entry, whatever, any deviations from the theory of the long run you can have situations where your supply curve ends--it falls short--before crossing the demand curve. And therefore what happens is you take the whole quantity of the supply that is available to you, but you take it at a price which is set at a higher value than the marginal supply price.

You're taking it at a price which is set by the demand curve. So in that instance, the demand curve is setting both quantity and price.

MR. SIPE: My name is Don Sipe. I am with the American Forest and Paper Association.

I want to go back to some of the things that were discussed a little bit earlier this morning about the energy adjustment, and particularly to talk a little bit about some of the items that Ezra and others were raising about, you know, how to estimate these, and whether it is better to use actual values.

There was some concern about using actual values of the years and going back that would create uncertainty. I think that uncertainty is there in any event. Anybody putting a bid in to this market either at CONE or at something else is going to have to be estimating what those energy revenues were.

And even if you have a boggy in there that's fixed at some energy set, they are still going to have to look at that boggy and figure out whether they're going to over-perform or under-perform for that boggy.

So the total recovery that they're going to get is going to be no more or less uncertain whether you are using actual numbers or whether you're using some other estimate.

So the idea that there is added volatility by using actual numbers and going back I think is a little bit hard to sustain. Because you can go back and adjust, but even if you had set it in advance, their actual revenues are going to be based on the revenues in that year and whether they meet or miss your boggy.

So in a sense you could either, as you suggested, Dave---I wouldn't say you were advocating it--but you could set CONE, leave it, and adjust out actual revenues. Or, you could put in some boggy and let the market adjust out actual revenues. But the adjustment is going to happen, and total revenues are going to be adjusted by those amounts.

So I am not sure there is a large distinction about, you know, where you set that capacity payment in terms of total revenues.

As a final point--well, not a final point yet--I heard different justifications for using historic values. One of the things that I think Mr. Stoddard said was that you want to try to wash out, if you've had past over- or under-recovery.

The problem is, if you're trying to incent new entry, that over- or under-recovery isn't the new entrant's over or under recovery. You are not washing anything out. You are getting a signal from other inventors who invested awhile ago. And the only thing that matters to the new entrant is whether that past experience is relevant to what they are going to see in the market.

So it is not a matter of regulatory lag in trying to wash things out of the market, it is a question of whether that past performance has any reasonable bearing on what you expect to see in the coming year. And actual revenues in the coming year would be a better match for that.

There also seems to be a little bit of conflict in some of the ideas about using past revenues and trying to wash out over-recovery with the idea that we are then going to go back and adjust them for tariff changes. Those seem to be missing apples and oranges.

You either try and wash out past over-recoveries because they were actual over-recoveries, and the idea is to wash them out through the system with time, or you try and make an accurate prediction of the future. But trying to somehow claim that you are doing both, we want to wash them out unless it looks like they changed, you might as well use actuals.

Finally, as a point, I think the most efficient way to do this--and it may be beyond the scope of what you would consider in this case--is not to do estimates at all. The market can wash these out exactly dollar for dollar, unit for unit.

Someone said we didn't want options. We didn't want to get involved in that. But actually putting this as a simple option and having CONE set with an obligation to provide at a strike price gets the price right for every unit. You don't have to estimate. You don't have to wash out. You don't have to do anything else. The market sets it. They estimate it going in and, you know, the market will clear it and you will get the right number.

MR. MEAD: Before you sit down, can you talk a little bit more about how the strike price would fit into this proposal that you have?

MR. SIPE: If you made a strike price,

essentially a call on energy, and you just set CONE and you set the strike price based on what you thought the operating cost of a new unit was going to be, whatever your proxy unit is, you matched your capital costs, the obligation on the unit is to provide energy when called at that price.

They will price that into their capacity bid, and your market will clear at a point that represents the people who know this business best, what their estimate is of what those revenues are going to be.

Whether they are right or wrong, once you give them that option, the market itself will adjust the revenues. You don't have to guess. You don't have to estimate. You don't have to have 205 filings. All you need to do is put the obligation on the people who can hedge it best and have them roll that into their capacity price.

The adjustment would be exactly the same as if you just left CONE alone, as you suggested at one point, and could accurately predict for every single generator exactly what their revenues would be in the market.

The risk is put on the party that is best able to hedge and is best able to estimate what is in the market. CONE stays where it is. You just get your estimate of a peaker. You adjust for fuel for your strike price wherever you think your peaker is so you don't have to set that in advance, you simply know the characteristics of your peaker for your capital costs. You let the fuel float until the year it is fixed. That is your strike price that can even be adjusted during the year. And the revenues are adjusted out by the market. You don't have to do it. And ratepayers are hedged.

MR. MEAD: How would you determine the strike price? How would you determine the strike price?

MR. SIPE: You would determine the strike price by taking whatever your capital unit is. Whatever your capital unit operating characteristics are. If it were a peaker unit which you knew was only going to operate in a certain number of years and has a certain heat rate and a certain fuel index, that is your strike price.

And folks are obligated to provide energy at that strike price when called. Now they make the estimate. If you're a coal unit, obviously you're going to make a lot of money at that strike price when you're called. So your capacity bid will reflect the fact that you think you're going to make a lot in the energy market.

People adjust around that price. But the people who are adjusting around that price are the people best able to hedge it. There's actually long-term hedging that can go on because these people understand how to hedge these things better than load, which is just purchasing in an Auction. But the market will adjust out the exact amount because they will have to roll the cost of the hedge into whatever the bid to CONE is, and that will raise capacity prices slightly.

The usual objection to this is that it combines capacity and energy. That is essentially what you are doing here anyway. You are telling us that we are going to flatten out this curve, we're going to get lower end for marginal revenues, the end for marginal revenue streams isn't working, we're trying to replace some of this in this construct. That is supposedly the missing revenue.

I think it is better to let the market do it directly.

MR. MEAD: Thanks.

MR. WEMPLER: I didn't know if the analysts wanted to chime in, but I am going to.

(Laughter.)

MS. COCHRANE: Please state your name.

MR. WEMPLER: Hi. Steve Wempler from Con Ed Energy.

I was actually going to comment about the peak energy rents before Don came up, so I am glad I waited because I think it is very appropriate timing.

Two concerns. One is I think a question. I was going to originally pose a question to Bob Stoddard about his energy call option, which is really what Don was getting into.

Under that approach where a capacity supplier is effectively giving to the market--and it presumably goes back to, any revenues from that goes back to loads, whoever the payers of the capacity are--if you're giving away a call option above a certain strike price, it means if the energy prices do rise above that you don't as an asset-owner have a hedge for that.

So while it is theoretically possible, it means that if I sell capacity and I have given up a strike price whenever power prices are above $200 a megawatt hour, if the price goes to $700, I'm not hedged for the difference between $200 and $700.

So then on the whole other side of the market, the energy market, I can't sell a normal bilateral contract. It means all of our energy trading and transactions have to change. And while theoretically possible, that is not a trivial task. It also impacts people's risk management policies, it impacts ICE trading, it impacts cross-border transactions; there is a whole bunch of baggage that goes with that.

To Andy's demand/response, a demand/response person may not have that intrinsic revenue. So somebody participating in ALM may have an issue with that. It may even change demand/response behavior. Because if customers now know whenever the price goes above $200 in my example they get some of that money back, they may not be as interested in responding to price.

So it is not as simple. And to my question to Robert Stoddard, giving away a call option, wouldn't that put somebody short in the energy market in that high price? So if they had sold at normal energy bilateral, wouldn't they be doubly short? That's a question for the panel.

MR. STODDARD: Well I think your instincts that bundling this call option with the capacity product changes everything else that's traded, and everything else that has already been traded including all the long-term contracts in the market that exists now, is correct.

It is a fundamental redefinition of what is the product that is being bought and sold. You sold the top of your energy already. What you now own as a capacity resource supplier is the spread between zero and the strike price.

So you can no longer sell the same load-following, price-following product you had been traditionally selling and that you may have already sold. You now are selling something that has the top already off--because that top has been purchased through the capacity market. So there are a lot of pieces going on.

I will point out that the idea of these options has been explored in the academic literature. For those of you who care, I have put in citations in footnote 12 on my panel comments today. These discuss some of the options. They are typically being used in markets that are isolated, or that are newly coming out of a regulated process into a more restructured process, so the issues of grandfathering and of market trading that Steve correctly raises are much less severe than they would be in PJM with a very active and long-standing energy market.

MS. PHILLIPS: Margie Phillips from Constellation Commodities.

What Don described is a great product in the bilateral market. Bring it on. We would love him to come and talk to us about it.

The capacity market is one that we are obligated to bid in, and then we're mitigated. It's a completely different issue, and the risks associated with it are completely different to then lock in a fixed energy rate as well.

It would be great if we could all predict Katrina, and we're willing to do that when we enter into a bilateral obligation, but this is a very different market where we're obligated to perform. There are a different kind of performance penalties. It is simply inappropriate to give this kind of option.

And it is sort of ironic that load says we're so worried about overpaying the generators, they should refund; you know, doing an ex poste refund. But, you know, they should also take all the risk that they're getting under-compensated, and that should not be our problem.

I think that is why the historic--I mean, nobody ever gets this perfectly, but that is why the approach to using an historic average for energy revenues makes sense. Frankly, you are going to win some years and you are going to lose some years, and that is why you average because that is what happens in the end.

But I would submit that this proposal of an option is simply not workable in the kind of market, capacity market, that is somewhat regulated.

MR. SIPE: First, Katrina is--sorry, Don Sipe again--Katrina is not the issue. I started this by saying that it would be adjusted for fuel in the year. We are not asking for a guaranteed price.

What we are talking about is the operating characteristics of a plant and hedging for fuel. This is a different market. But, you know, from the consumers point of view you are trying to move us to a different market. You can either do it well, or you can do it poorly.

And we think that the issue of fundamentally changing this market has to be addressed on all fronts. It is a different market. It's a different idea. But, you know, RPM is a pretty different idea. But as far as things like a guaranteed price under Katrina, I mean that is adjusted for a model.

The model would take care of that by adjusting the fuel index for real-time fuel. The question is, you know, if you're going to start setting a PER adjustment to start adjusting this out, you are essentially in some sense putting an option on that energy anyway. Because people are still going to have to guess against that.

Consumers would like to see it be an explicit option, and I think that is why you are getting--I mean an explicit option--that's why I think you are getting proposals to adjust out real demand.

Once you adjust out real prices, once you are doing that, and that's the preferred route if you're going to try to do this accurately and not just do it historically, it is much simpler just to have them give an option. Because that is what they are giving when you start adjusting out a real price, and that was Robert's objection. But I think real prices are the proxy you are trying to get. That would be accurate. And accuracy matters if what you're doing is you're replacing revenues that they say they're missing.

MR. MEAD: Roy.

MR. SHANKER: Roy Shanker. This is a great example of fighting the last war. The notion of the PER adjustments and the need to do this made a lot of sense in a market like New England where monthly capacity prices are sort of meaningless. No one can offer cost of entry and make a bid that means anything.

This is what I was trying to get to before about take advantage of what is being offered to you in the design. You don't have to figure this out. You're going to have empirical bids by people who are saying I'm willing to enter the market for X dollars. Okay?

That person takes into account his own estimate of his cost of capital, how is own estimate of the cost to build, his own risk assessment of whether or not he can permit and close out, and his own estimate of what he thinks he will get for net energy revenues, and he gives you a number. And as long as we can be reasonably comfortable--and this is where market monitoring comes in--that we are getting legitimate bids for new entry, you can ignore this entire debate.

If someone wants to sell a call, they can sell a call. If someone just wants to offer capacity into the market, they inherently are going to be offering empirical numbers that already net out whatever their expectation is of energy margins, and you're done. You don't have to do this.

Don't set up a bureaucracy to deal with this minutia. Set up a methodology to understand what is coming in in terms of new energy, net capacity entry offers into the market auction. That is where the focus should be, and that is where the energy should be expended.

This is a debate that will go on forever. Whereas, if you get 50 bids in and you can screen them to see if they're competitive, you're done.

MR. MEAD: Roy, before you go, you and Bob Stoddard and perhaps a couple of others have made the observations that the supply curve is basically horizontal. And I guess the one question I have is:

The net capacity price that a new entrant thinks it needs strikes me perhaps depends on how much capacity he expects to be out there. You know, if you have a really generous demand curve so that you're clearing at IRM plus 10 percent--to be extreme--you're going to have a lot smaller energy revenues, and therefore the net price you need in the capacity market will be higher I think than if you have a more conservative curve where on average capacity is only 1 or 2 percent above IRM.

Do you agree with that observation? And how much does that affect the supply serve for capacity?

MR. SHANKER: Well again it affects quantity.

Because at some--there is noise. I agree with Jonathan's comment. Particularly in small LDAs we're not going to see a perfect steadystate fully divisible new entry world. But in general, all that you are talking about is somebody is going to assess, based on where the curve is, the quantity that will be in the market and their expectation of net revenues at that point, and they will bid it.

I mean it is not precise, but the precision comes in terms of the aggregate of people figuring out that risk, figuring out their costs and what their expectation is, and offering it in. That is why I said one of the things I liked about Andy's proposal was to smooth out some of the rough edges in the small LDAs by offering this ability for four or five years, however--I think it's five--for that unit to set marginal costs.

And that says somebody will still make the assessment. They will still have to deal with what you are talking about, but you just set the quantity you want. If you want it to focus at IRM plus 1, you can set the curve that PJM is proposing, and you can adjust it based on the empirical net CONE that is bid into the market. And that will oscillate around there, and that is what our feedback mechanism does, and we will get the general properties that Ben has modeled. You know, we will actually get some information on that and you can fine-tune the risk aversion, and you are sort of done.

To get back to your question, I don't know how it adjusts it other than you pick the parameter. That tells you the quantity. And then people are going to make their own assessments in the market based on their own risk aversion and their own costs and give you a number.

MR. MEAD: I guess, I mean when we look at the estimates of ancillary service revenues--I think $8 per kilowatt year versus in the thirties--that suggests to me that the slope of the net CONE supply curve could be fairly steep, and that what we are doing is not just picking the quantity but also the price.

MR. SHANKER: No, I--now I understand what you're talking about.

MR. MEAD: Because the price, the required price, capacity price, at IRM plus 10 has got to be a lot higher than the required price at IRM plus 2.

MR. SHANKER: Except that what you are going to do is you are going to give people the knowledge of I'm looking to set a curve of this general shape with IRM plus 1 as the target. And so they are going to understand that that is the expectation and they are going to be bidding in based on their expectation of energy margins at IRM plus 1, or something like that. They will make their own risk adjustment to that.

So you are going to see a spectrum of people, and they will give you some empirical bids. And let's say hypothetically their net bid runs from $60 to $70. We might want to talk about how do we analyze that to then adjust the curve for the next auction, or for the next three-year auction, however we finally wind up adjusting it.

But there is going to be a consensus out of those people that offer in. If you want to use the cheapest ones, they are the ones that took the risk and bought it all, that's the one you use. And it will be self-adjusting. And you don't have to think through all this; you just have to let people know institutionally what the rules are, and they'll do it all for you in terms of their bids. Just tell them how you are going to set the curve.

I may use the average, or the lowest of the competitive bids, or whatever number you come up with, and I am going to center it on IRM plus 1 and then stand back and filter the bids that come in and use that for the next adjustment cycle. And you don't have to do any of this.

MR. WALLACH: I would suggest that--at the risk of beating a dead horse--that in the long run, yes, you can stand back, and in fact you can stand back and you don't need a slope demand curve because you're talking about, you're talking about new entry--again putting aside the lumpiness, the noise issues in the smaller areas, you're talking about new entry setting the price at whatever new entry decides is the appropriate price for them to recover their costs and make a reasonable return.

So if you want to stand back, you stand back by having PJM say we need an IRM of 15 percent, and you go ahead--and we need it four years from now, and in the long run we're talking about a situation where with load growth you're always needing new entry, they're going to set the price at the new entry price. You don't need a curve.

Well as Mike Goldenberg observed, the Commission has found that a slope demand curve is appropriate here. And I don't want to refight that war, but I think they did have very sound reasons to do that; that, yes, in the long run, we have this property. But the long run is made up of a series of short runs, and we do have an interest, a compelling interest, in having some stability in the series of short-run auctions. There is a public interest in that.

So that is the extra stability that comes from having the slope demand curve. I think it is good we have it.

MR. MEAD: I would like to put an end to this particular discussion. On rehearing you can argue that general point, as Mike mentioned earlier. Our purpose for today is to assume that we are going to have a demand curve that is sloped, and what are the parameters.

Are there any other comments before we close for the day?

(No response.)

MR. MEAD: Well thank you very much. This has been very helpful. For those of you who are interested in opt-out, we will resume tomorrow at nine o'clock in the morning. Thanks very much.

(Whereupon, at 4:55 p.m., Wednesday, June 7, 2006, the meeting was recessed, to reconvene at 9:00 a.m., Thursday, June 8, 2006.)