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BEFORE THE ILLINOIS COMMERCE COMMISSION

In Re the Matter of:)
)
Electricity Policy Committee)
Meeting, Resource Adequacy.)

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Reported by: Jean S. Busse, CSR, RPR
Notary Public, DuPage County, Illinois

COMMISSION MEMBERS PRESENT:

MR. DOUGLAS P. SCOTT, Chairman;

MR. JOHN COLGAN, (Via Telephone);

MR. MIGUEL DEL VALLE;

MS. SHERINA E. MAYE; and

MS. ANN McCABE.

I N D E X

COMMISSIONER McCABE: Good morning. Do we have Commissioner Colgan on the phone?

COMMISSIONER COLGAN: I'm here.

COMMISSIONER McCABE: Excellent. Welcome to the Resource Advocacy Policy Meeting.

Pursuant to the provisions of the Open Meetings Act, I now convene this policy session of the Illinois Commerce Commission to address resource adequacy in Illinois.

With us in Chicago are Commissioner Doug Scott, Commissioner Miguel del Valle, Commissioner Sherina Maye, and on the phone is Commissioner John Colgan.

I welcome and thank all the panelists for presenting on this topic today. They bring great experience and a variety of perspectives on resource adequacy.

To start off, I want to let the Chairman say a welcome introduction.

CHAIRMAN SCOTT: Sure. Thank you very much, Commissioner McCabe.

I first want to thank you and Ariel

Tesher and Cameron Schilling for all of the work in putting this together. You've got a great panel assembled, and a lot of good information I'm sure is going to come out of today's session and probably lead us to want to follow up and do even more on this subject in the time to come.

You know, as Commissioners we use these policy sessions to kind of highlight issues of importance and do it removed from the constraints of a case, especially an issue like today's which doesn't necessarily show up in our cases.

It's a very complicated subject. Even some very smart people that I deal with on a regular basis who touch pieces of the energy world don't always understand the world of FERC and NERC and the RTOs.

Since generation has been gone from our regulations for over 15 years, we've really gotten away from a lot of this discussion at different times, but it's very important.

Folks here have heard me say probably ad nauseam that our mix of fuel that we've got

in Illinois is half nukes and half traditional coal. We don't know what that's going to look like 20 years from now, but we're pretty sure that's not what it's going to look like 20 years from now.

While mix is a little bit different issue, it does play into the whole issue of adequacy, both in the short term and long term.

We have a robust RPS. We've got energy efficiency that all plays into it as well. There's transmission issues. In the future, we'll look at things like energy storage and distributed generation.

I have this whole idea of completely changing the business model for electric utilities. So it makes us want to participate and look at these issues in greater depth. That's why I appreciate the work that Commissioner McCabe and her advisors have done in putting this on today.

You've got the issues of the EPA regs, both the ones that have already been issued and the greenhouse gas regs that we know are

coming, and we've seen what natural gas prices have done to the markets in the fuel mix, not just here but around the country, and the adequacy issues as well.

And if we found that we needed generation here, we've got a very complex set of laws that we're going to need to work through probably at some point.

The Illinois Power Agency has some authority to do some generation under the law, as do we, but since we don't regulate generation anymore, it's pretty difficult for us to figure out who we would talk to if we wanted to actually do something to add generation here.

The whole issue of integrated states which are competitive like Illinois is really, really important.

I know that Commissioner McCabe spent a lot of time working on the PJM side working through OPSI and Commissioner Colgan on the OMS side through MISO and then spent a lot of time working on the issues that you're going to hear about today.

So I really appreciate you taking the time to put this together and help flush some of these very complicated issues out. Thank you.

COMMISSIONER McCABE: Thank you.

Before we begin, I want to remind the panelists and attendees that a small informational section in the open IPA Docket 13-0546 pertains to resource adequacy.

The panelists have been notified, and we need to avoid any discussion of this year's procurement plan and the procurement decisions it discusses with regards to what the IPA or the ICC should or should not do.

In addition, we have some transmission matters currently before us that we should avoid. It's likely that either in the room or online there will be some trade press. So be mindful of that.

Before Commissioner Colgan gives some remarks, I will share a few thoughts about this topic. The Commission has two fundamental questions we gave to the presenters.

First, how does Illinois currently ensure that it has the resources it needs for the future?

Second, is our State facing a resource adequacy problem -- to which I would add -- in the short, mid, or long term?

When consumers and businesses flip their light switch, they expect the lights to go on. They don't care much about how that happens, except that they want low energy prices and stable power.

What many consumers do not know but people in this room are very aware of is that behind that light switch is an entire network of utility companies, grid operators, generators, suppliers, regulators, and thousands of others who work each day to ensure that there will be enough power for tomorrow's needs.

Illinois used to be a traditionally regulated state where the issue of resource adequacy was the responsibility of vertically integrated utilities and their regulator, the Illinois Commerce Commission.

Through integrated resource planning, the Commission would develop the framework to ensure that utilities had enough generating capacity for their customers in the future.

Now our restructured State largely relies on two RTOs, PJM and MISO, to ensure reliability on the grid.

As President of OPSI, the Organization of PJM States, as Chairman said, I spend much of my time on PJM issues, including their capacity market.

PJM's Reliability Pricing Model is a three-year forward auction to provide a price signal for supply resources. This model has been tweaked after each annual base auction, and this year is no exception.

Through the PJM stakeholder process, we have seen new proposed requirements for demand side resources, limits on imports from other regions, and changes to how demand and supply side resources can buy out of their obligations. Each of these changes is important and deserves our attention.

As a Commissioner in a restructured

state, the timing needed to devote to one RTO can be overwhelming, let alone two, and the complexity of these markets can be daunting and frustrating even for some economists. As a PUC, we have limited resources.

We need to pay attention for three main reasons.

Commissioner Colgan, are you on mute?

COMMISSIONER COLGAN: No. I will put myself on mute right now.

COMMISSIONER McCABE: Okay. In just a few minutes, you can un-mute.

So for three reasons we should be looking at this. First, 70 percent of a customer's bill is impacted by the wholesale market, including energy and transmission charges, ancillary services, and increasingly by capacity charges. This makes up the majority of the bill and can have a large impact on a customers' bottom lines and the economy as a whole.

Second, with the rollout of the Smart Grid, our retail and wholesale markets are now being merged. Consumers will have the ability

to choose realtime rate structures, respond to wholesale price signals, and shift their load to reduce peak usage.

These are all great things for consumers. They can also help grid operators ensure reliability, help distribution companies lower peak stress on the system, and reduce the need for new and expensive peaker plants.

These two markets are moving together in a rapid way, and State PUCs and the utilities play a vital role in ensuring they are merged successfully.

Third, reliability is paramount. Consumers and businesses ultimately pay for the capacity, and we need to ensure they are getting value for their money.

There are a number of questions we can ask and the panelists will be addressing, such as: Are capacity payments purchasing reliability, or are they simply compensating existing resources for no added benefit?

Is a three-year-forward annual product enough incentive for new generation, or should

it be longer term?

Can lower-priced demand side resources provide the same reliability benefits as supply side resources, and is it reasonable to treat them the same?

Although our Commission may not have the same legal authority it once did, I believe the Commissioners and State regional committees, such as OPSI and OMS, can play a key role in providing PJM, MISO, and FERC with our view on how these markets can be structured to create least-cost power and ensure reliability on the grid.

As the Chairman referenced, today's discussion will be the first discussion of many discussions on this topic and will help us learn more on how future reliability is ensured.

With that, Commissioner Colgan?

COMMISSIONER COLGAN: Thank you, Commissioner McCabe.

I'm hoping you can hear me now.

COMMISSIONER McCABE: Yes.

COMMISSIONER COLGAN: Okay. Well,

good morning to everybody. I'd like to thank everyone for their patience in accommodating me to participate in this meeting remotely. I couldn't make it to Chicago today.

I also want to thank Ann McCabe, Commissioner McCabe, for her leadership. She has, again, been instrumental in putting this together. Ann is the President of OPSI, and I serve for the Illinois Commerce Commission on the OMS Board.

Ann and I have had the occasion to talk back and forth considerably about various issues that have come about in the wholesale marketplace. The places that you're concerned with mostly -- not concerned with but are involved with is PJM and MISO.

Before I go into my final thoughts, I want to thank Chairman Scott for his leadership to encourage that we have these ongoing policy discussions. I think that this is an important role that we play in terms of gathering information and hearing out the various issues from the experts in those fields.

So I'm thanking Ann and I'm thanking Doug but also the role that the assistants play, Cameron Schilling and Ariel Tesher. They all play important roles in accommodating our participation in these wholesale markets with OPSI and OMS.

I'm going to be brief in my comments, but I do want to say a couple of things. One was to kind of frame why we're here today. I think that's so that we can begin to learn and understand better from what is happening in wholesale markets so that we can get a better feel for where things are at currently and help us chart our course towards the future.

There is a lot happening in this space, and there's a lot that everybody needs to try to get up to speed with. The people we'll be hearing from today, they work in this environment, and they understand these topics and these subjects in great detail.

This meeting is not to in any way question are they managing their wholesale markets appropriately because I don't think we have a concern or a problem right now. In our

sense of responsibility as Commissioners, we need to stay abreast of these issues.

Hopefully, the discussion we have today will open some doors for people to begin to understand better what's happening in this space because, as Commission McCabe said earlier and Chairman Scott said, too, there are people in this State who understand these issues.

There are a lot of people who we depend on to understand the issues, but it's not that everybody understands what's happening here. So we need to open those doors to gather that information, and today is a great forum for that to happen.

So I think we need to try to understand, and we need to contemplate our understanding of what we learn. Then we need to chart a course towards the future. We'll keep going on that today.

With that, Commissioner McCabe, I will go back to you.

COMMISSIONER McCABE: Thank you, Commissioner Colgan.

Our first presenter is Randy Rismiller, the Director of our Commission's Federal Policy Program. Randy has a Bachelor's from the University of Cincinnati and a Master's Degree in economics from Ohio State University.

He joined the Commission in 1990 as an economic analyst and in 1998 became Manager of the Federal Energy Program. Randy and his staff monitor both RTOs and advise the Commission on Federal energy matters. Randy will overview today's topic.

Thank you, Randy.

MR. RISMILLER: Thank you, Commissioner. Yes, I will dig right in.

I've been asked to provide an overview. So please bear with me. I recognize that some of you have a lot more expertise in this area and probably don't need a lot of this overview. Nevertheless, we're going to proceed.

There are a lot of definitions of resource adequacy, so I put one up here on the first bullet point. I think the main

take-away from this is that this is a planning function, you know, preceding realtime operations by a considerable margin, which is not nailed down but measured in the context of years.

Resource adequacy is related to some of FERC's jurisdictional responsibility with respect to ensuring transmission grid reliability and just and reasonable wholesale power sales rates.

Nevertheless, these are separate functions, and resource adequacy is specifically reserved to the states.

Also, resource adequacy is different from resource diversity, other energy industry policy goals, or specific attributes of generated units. So it's important, as we keep resource adequacy in mind, that diversity and adequacy are related but separate topics.

Reserve margin: Traditionally resource adequacy is served through employment of a reserve margin, an amount of capacity in a planning context exceeding expected loads.

PJM and MISO for our regions are the

entities who develop the reserve margins for their regions. Reserve margins are calculated on the basis of loss of load expectation.

Traditionally, the target sent down by regional and national reliability organizations has been no more than one load outage in ten years due to inadequate supply resources.

As you can see, this is somewhat of an arbitrary standard that's been used for generations and still predominates in the industry.

As I said before, reserve margin has a dual purpose, both for the purposes of resource adequacy targets as well as transmission grid reliability standards. So it serves these two related but distinct purposes.

The role of FERC: FERC is the main actor in this because FERC has, as I said before, both transmission grid reliability responsibility as well as wholesale power sales rates responsibility.

But FERC can't order construction of

generators. It's specifically not permitted, but FERC does use the authority that it has to induce or cajole or establish the framework by which resource adequacy can be attained and grid reliability can be maintained in the context of FERC's targets.

States have resource adequacy responsibility; and whether or not that's exercised by the state PUC or maintained by the legislature of the state is up to the legislature.

In general, to fulfill its responsibility for resource adequacy, states have some options.

Because FERC has responsibility in the areas that I indicated and can exercise that responsibility through the RTOs and their regional energy and ancillary services markets, the state may be in a position to effectively determine that this responsibility that they hold can be met through these other mechanisms in a satisfactory manner.

Alternatively, they can pursue resource adequacy initiatives separate and distinct

from the grid reliability initiatives pursued by the RTOs.

When states act, court precedent indicates that they are not permitted to infringe upon the areas where FERC has responsibility. I think I've covered a lot of this. The RTOs are the entities which are responsive to the FERC.

One thing about maintaining grid reliability is that the generation has to be in the right locations and available at the right times. Right locations and right times are defined by physical transmission constraints, not by state boundaries, not by politics but by physical transmission constraints.

So this is an important factor to keep in mind when assessing how and whether to act on the resource adequacy issues.

This is just a slide talking a little bit about the evolution of how FERC and the RTOs have gotten to where they are with respect to the mechanisms by which they maintain transmission grid reliability through

markets.

Initially, it was felt that locational marginal pricing using single clearing price auctions would, in and of itself, be likely to send sufficient price signals and produce sufficient revenues for generators to lead to an adequate supply of generation, therefore, resource adequacy.

Eventually, folks realized that in order to maintain the reserve margin standard or reliability standard set by reliability engineers, this probably would not be sufficient without some modifications, which I'll get into in a few minutes.

The initial idea for RTOs essentially encompassed the energy-only market, and that's Method #2 here. As I indicated before, energy-only markets have been determined not to be sufficient to produce enough revenue to lead to the maintenance of the desired and directed reserve margin.

One way to modify or revise those markets is to add scarcity pricing elements to that. Scarcity pricing is an administrative

mechanism by which energy prices escalate as operator reserves diminish and become scarce. This sort of arrangement leads to more revenue generation, which is thought to be the driver about maintaining reserve margins.

Method #1 is if the RTOs in their regional market are going to cap the energy price, the spot price, the alternative way of producing additional revenue streams is either through capacity auctions or bilateral contracts.

So these are some different ways that RTOs conduct markets and administrative mechanisms to produce revenue sufficient to guide generator entry and exit decisions.

Of course, these things have been controversial. The energy-only market leads to extraordinary price volatility as well as high price during certain hours. It's determined to be generally an uncertain driver of revenue streams.

That's definitely enough -- and this is ironic. Capacity markets were developed in order to smooth out these volatility and

revenue uncertainty issues.

Quite frankly, the capacity markets, as they have operated so far, are also criticized for uncertainty, volatility, and revenue uncertainty in addition to the administrative complexity of the capacity auction design itself.

As I also mentioned, traditionally states have historically used the vertically integrated utility structures and integrated resource planning as the methods by which they ensure resource adequacy; and that's still the case in many of the states, both across our region as well as nationwide.

Now, integrated resource planning provides stability, predictability, and continuity. Its downside -- and a major downside -- is that risks and costs are borne by ratepayers.

The other element -- and I mentioned this before, I believe -- is that once the state is part of a region that has a centralized and RTO-operated spot market and other mechanisms, the state would need to find

ways to accommodate that or work within that context in exercising its resource adequacy responsibility.

So I jotted down a few facts here or statements about Illinois. In 1998 with the restructuring law, the General Assembly effectively eliminated the integrated resource planning provisions that were in the statute at that time for Illinois, which effectively places a greater degree of reliance on competitive wholesale power markets as a mechanism for ensuring resource adequacy to customers in Illinois.

This is the primary reason why the ICC has put a lot of emphasis since the mid '90s on development and improvement of these wholesale spot markets operated by the RTOs.

But it's interesting to note even with the 1998 action of the General Assembly, the General Assembly has also acted over the years in areas such as clean coal and renewables and other areas that are tangentially related to or affecting resource adequacy and diversity to some extent.

The other interesting thing to note is that the provision in the Public Utility Act that authorizes the Illinois Commerce Commission to direct the utilities to build generation still exists in the Public Utilities Act as it always was. It wasn't altered or eliminated with the 1998 action.

I just put this up. I think we all know this, but load potentially always pays. It pays to maintain the resources sufficient for transmission grid reliability, it pays to attain the resource adequacy standard or suffer the consequences if those things are not accomplished.

Currently in the Midwest, resource adequacy and reserve margins are more than adequate. They are above the targets set by the RTOs.

This slide has a little bit of data about the capacity of PJM's most recent capacity auction, both price and quantity, and the results of MISO's recent auction. You can see capacity margins are well above 20 percent.

COMMISSIONER McCABE: Has that been true for recent years that reserve margins have been higher?

MR. RISMILLER: It's certainly true since 1998 in all cases, but this may not always be the case going forward.

This Slide 14 talks about some matters that may affect the reserve margin and resource adequacy generally going forward. Generally, the issues out there are actions of environmental regulators as well as the effect of the natural gas price.

So we now have in place the MATS rule as well as several others and are awaiting the US EPA action on greenhouse gas rules.

We've seen some analysis from MISO -- and they may get into this in their presentation -- where they have done some forward projections and have arrived at a conclusion that under certain circumstances and certain scenarios, the MISO market may fall short of its target reserve margin by the 2016-2017 delivery year.

I just threw up a slide here at the end

just to point out that policymakers and regulators have been struggling with this resource adequacy issue for a long time, generations in fact. We're still somewhat in this paradigm that we've always been in, but it may not always be that way.

There are ways that the industry could change that would effectively moot or remove this resource adequacy conundrum that we've all been in throughout our careers.

I just want to point out that these kinds of paradigm shifts are not uncommon in the energy industry, and we may see such paradigm shifts in the future.

That's basically my overview. Thank you very much.

COMMISSIONER McCABE: Questions from anyone?

Thank you for laying the groundwork for today's discussion.

Questions, Commission Colgan? Okay.

We'll proceed with the first panel. We have several panels today. Again, we're very fortunate to have the number and variety of

experts today.

The first panelist will address resource adequacy from the Regional Transmission Organizations or RTOs. PJM and MISO collectively manage grids that provide energy to over 100 million customers.

It's important to remember that the RTOs not only manage the grid, but they also administer the economic markets by which the wholesale energy products are bought and sold.

In addition, we are fortunate to have the market monitor from PJM to provide some independent oversight for the PJM markets.

First from PJM, Stu Bresler, Vice President for Market Operations; for MISO, Richard Doying, Executive Vice President of Operations and Corporate Services; and from Monitoring Analytics, Dr. Joe Bowring, PJM's market monitor.

Stu?

MR. BRESLER: Thank you, Commissioner McCabe and the rest of the Commissioners. It is indeed a pleasure to be with you this morning. Thank you very much

for having me this morning.

So what I thought I would do today in order to get at the answers to the two high-level questions about how is resource adequacy maintained in the state of Illinois and does the state of Illinois have a resource adequacy issue is first to really help to further define what we mean when we talk about capacity and resource adequacy and then briefly describe the PJM mechanism by which we maintain long-term resource adequacy for the PJM region and then go over some statistics and some data that shows how that model has worked since its inception in 2007.

So Mr. Rismiller did an excellent job of overviewing resource adequacy and the objectives and the current mechanisms for how resource adequacy is maintained. I thought it might be helpful to emphasize just the difference between capacity and energy and what we talk about when we say "capacity and energy."

I think when most people think of the delivery of electricity to the end-use

customer, they think of the energy product. Power plants produce electricity. It's instantaneously transmitted to the end-use customer and instantaneously consumed.

There are markets that set the prices on five-minute, hourly, and on a daily basis for that energy product.

Capacity is a bit different because capacity is not so much the actual energy itself but a call option on the energy in emergency conditions.

So it's a mechanism by which a central operator, like an RTO, can commit resources for the long term that can satisfy the needs of the region, again, when the criticality of emergency conditions arises.

So day-to-day, a resource that is committed as a capacity resource for a region can elect to sell its energy really wherever it wants. So a generating resource in PJM, for example, that's committed as a capacity resource can elect on a day-to-day basis to sell its energy outside the region.

Demand resource can elect to reduce

economically if it chooses. This certainly is not required to reduce its demand until it's actually called upon to do so by the RTO.

During emergency conditions, capacity resources that are committed to the region as capacity resources, the energy goes nowhere else but that region. So that is the purpose of the capacity product is to provide that call option on the energy.

We have seen instances as recently as this summer and fall when we've gotten to the point in PJM of needing to go call on those resources in emergency conditions.

During July, specifically the week of July 15th and again in September on September 9th, 10th, 11th, PJM was required to call on energy resources that were committed to PJM as capacity resources in order to serve the energy needs of the region during emergency conditions.

There are two separate products, two separate payments, and capacity resources receive that capacity payment every day of the year because they commit themselves to the

region to say that when called upon, they will deliver the energy to the RTO that has committed.

So why did PJM move to the Reliability Pricing Model as its capacity construct? Prior to 2007, PJM had a capacity market. It was a much shorter-term market of only annually, monthly, and daily, and we decided in 2006 that we needed to move to something different.

The reason is because we saw a serious dichotomy of several indications. First of all, in the top left-hand chart there, you see the capacity prices in PJM together with the bars that represent the retirements of generation in PJM.

On the lower right-hand side we see a trend of the anticipated installed reserve margin in PJM looking out in the future starting in 2006/2007.

What we saw was a trend of increasing retirements of generating units, declining reserve margins but at the same time declining prices for capacity.

So the capacity market PJM was operating was not sending the price signal that truly represented the future of the capacity balance in the PJM RTO, which is why we needed to move to something different. That's why we instituted RPM.

So given the limited time frame that I have this morning, I have endeavored to distill the fundamental elements of the RPM construct into a single slide. I thought that might generate some surprise, yes, but we'll see how we do.

So RPM -- and Mr. Rismiller highlighted it a couple of times -- is a complex construct. There are multiple auctions in the construct.

There's a base auction and incremental auctions, significant and very critical market power mitigation mechanisms that really, frankly, wouldn't be possible without the transparency of a centralized auction, performance requirements, a self-supply auction and all this complexity.

But at its core there are several

fundamental principles to RPM that underlie the whole construct and are really what make it function the way it needs to.

First of all, in the bottom left-hand corner there is the establishment of the resource adequacy requirement.

In PJM, PJM conducts an independent centralized load forecast for the PJM region that goes out more than this but at least three years into the future in order to support the RPM construct, and we also calculate the installed reserve margin for the region, as Mr. Rismiller described.

It's on the basis of PJM's load forecast with that PJM determined installed reserve margin -- we do get stakeholder and board approval of that installed reserve margin every year. On the basis of that load forecast with that reserve margin tacked onto it, we procure capacity resources for the PJM region.

Again, as Mr. Rismiller highlighted earlier, we do so on the basis of the location of those capacity resources. So the physical

constraints on the transmission system can limit how much capacity can be transferred from one area system to another.

So it is very important to make sure that the load forecast and reliability requirements are developed on a locational basis so that we can make sure that capacity is committed in the correct locations to ensure reliability everywhere in the footprint, both in the Illinois portion of the footprint as well as other portions of the PJM footprint.

Then last but not least, as far as the fundamental principles are concerned, RPM or Reliability Pricing Model executes a forward commitment for that capacity. So we're looking three-plus years into the future when we can make capacity.

To do so any shorter would significantly limit the ability for new entry of capacity resources to compete alongside existing generation of resource and demand response. So a forward horizon is absolutely necessary in PJM's view in order to operate an efficient

capacity market from the standpoint of ensuring competition among all resources.

As a result of this construct, three years into the future, PJM has a very good handle on the resource mix that will be satisfying the reliability needs of the PJM region, the locations of where those resources are in order to maintain that reliability on a locational basis, as well as the reserve margin that we will have in place, again, three years into the future.

The last component that is not on that slide and that I should highlight, although it quickly gets into the weeds and the details, is that sloped demand curve for capacity resources.

Mr. Rismiller mentioned the volatility and that forward capacity constructs are intended to smooth out the volatility of capacity prices; and without the sloped demand curve, we would not be able to do that at all.

At the end of my presentation I'll get to some additional improvements that we are looking to make in RPM in order to assist with

volatility.

So that is the mechanism by which PJM ensures resource adequacy for the PJM portion of the state of Illinois as well as the entire footprint.

So now the question turns to: What is the state of affairs? How well has RPM worked?

We've had this auction format in place and this capacity construct in place since the 2007/2008 delivery years, which you've heard for 2007 was the first delivery year for which RPM was effective.

We have conducted ten years worth of base auctions. So we have now committed resources out through May 31st of 2017; so from a summer peak period standpoint, out through the summer of 2016.

In a nutshell, we believe that RPM has worked to ensure the long-term resource adequacy of the PJM region.

As Mr. Rismiller pointed out, all the way out to 2016, reserve margins have consistently been in excess of the

requirements of the footprint which, if you remember, before we instituted RPM was not forecast to be the case as soon as the '09-'10 delivery.

In those intervening years, we did have our reserve margins dip down close to the actual installed reserve margin requirement in PJM; but given the RPM construct and, again, the utilization of that sloped demand curve, we now have reserve margins that, again, are in excess of the minimum IRM that we calculated.

We have seen that the prices resulting from the RPM auctions have been consistent with the supply and demand conditions in the different locations of the footprint.

We have seen delivery years such as '12-'13 and '13-'14 where at the time the auctions were run, there was, unfortunately, still significant uncertainty with respect to the advancement of environmental regulations, and we had a bit of a glut of capacity in the RTO. We've seen prices as slow as $17.

We have also seen prices as low as $350

in certain constrained areas of the PJM footprint where we are closer to the minimum reserve margin in those areas because of locational constraint.

So, again, the pricing mechanism has worked to make transparent where supply and demand is tighter in certain areas of the PJM region.

We believe RPM has also fostered the necessary competition to ensure the efficient procurement of resources to meet the reliability needs of the region and also have been able to effectively respond to the advancement of the environmental regulations and really the shift that we are seeing from the aging coal fleet to the natural gas resources that we are seeing develop in our region.

So this is a graphic just showing really where we have seen retirement notifications in the PJM footprint. You can see the Illinois portion of the PJM footprint in the top left-hand corner of the diagram.

Between 2011 and 2016, PJM has already

received notifications in excess of 20,000 megawatts of generation retirements, and that is well in excess of 10 percent of the installed capacity in the PJM footprint.

So it's a significant amount of generation that we see retiring simply because they cannot financially make ends meet and make the necessary capital improvements in order to meet the environmental regulations that we're seeing.

The green dots on this chart, though, are the new generation that we have seen coming through the PJM queue process, clearing in the capacity auctions, and actually are planning to build or are already building in the PJM footprint.

PJM also does conduct forward-looking analysis even beyond the RPM auction in order to analyze how many retirements that we can expect, what the generation mix looks like in the future.

The transparency of the prices that we see through the RPM construct three years into the future allows us to get a much more

detailed look at exactly, from a revenue standpoint, what generators' financial situations look like so we can anticipate retirements even before receiving notifications from the actual owners.

Obviously, we keep all of that confidential. It is simply a PJM analysis, but it does allow us to anticipate much better what we do see in the future.

CHAIRMAN SCOTT: Before we leave that slide, could you talk a little bit about the revenue circumstances in Illinois?

MR. BRESLER: Sure.

We have seen some retirements in the state of Illinois -- those are the red circles up there -- again, the majority of which are older, smaller coal-fired generating resources that, again, the capital improvements necessary to meet the environmental regulations just don't make sense financially.

Then we have seen some new entry in Illinois as well, some combined cycle entry as well as renewable resource windmill penetration, a new entry in the state of

Illinois.

So given the 20,000-plus megawatts of retirements, we have a pretty good inkling that there are likely more to be coming in the future.

Since the inception of RPM, we have seen over 28,000 megawatts of generation addition in the PJM footprint.

The vast majority of those additions are the two bars on the left-hand side of this chart, natural gas fired, combined cycle, and combustion serving units, but we have seen some other types of generation additions as well, some coal in some sections of the footprint, some upgrades to nuclear plants, and then some of the renewable resources that I mentioned as well. So significant amounts of generation addition in PJM through the RPM construct.

I mentioned early on demand response, and we have seen a significant penetration of demand response through the capacity auctions. In the initial stages of the retirement notifications we were seeing, demand response

was, if you will, some low-hanging fruit, some really efficient ways to fill the void, if you will, left by some of those retirements.

We do believe that demand response is reaching a bit of a point of maturity in the capacity markets. So we do expect that to plateau at some point here where signing up even more demand response gets more costly and is probably at competitive levels with some of the other resources that we're seeing playing in the market as well.

Then last but not least, as far as managing, again, the shift in fuel base from coal-fired generation to what we're seeing as far as natural gas, looking out through the 2016/2017 delivery year, you can see that for the first time in our history, we see natural gas-fired generation from an installed capacity standpoint exceeding that of coal-fired generation, again, starting in 2015/2016 but by more than 14,000 megawatts in 2016/2017.

So we can anticipate this occurring in the future thanks to the forward-looking

nature of the RPM construct.

Even given its success, RPM is certainly not perfect; and we all recognize that there are improvements that could be made to RPM.

So this slide really just lists a few things, and Commissioner McCabe actually hit them in her opening comments this morning. So I won't belabor them too much.

But we do believe that we need to make sure that the imports of capacity from resources external to PJM can be reliably delivered on a long-term basis.

In fact, we're working with MISO on fact-finding-type investigations. This is one component of that fact-finding process, along with MISO.

I mentioned demand response and its significant penetration. Given the way we have implemented demand response in the RPM auctions, there appears to have been a suppressive impact on the price for generation and annual resources.

We need to make sure that that does not occur going forward. So that's really the

second bullet under the first two.

We do need to make sure that RPM remains a physical product. Other markets in the electricity sector that PJM operates, we encourage the participation of financial players because it adds competition and liquidity to the markets.

RPM is different. It is physical, and it is to acquire the resources necessary to meet the long-term reliability needs of the region, and we need to make that there is no speculation occurring in the RPM construct that does not involve the intent to deliver physical resources in RPM. So we're moving forward with that as well.

Then given the significant penetration of demand response, we need to make sure that it can be operated effectively and efficiently by our operators in realtime.

So we are looking at some changes to increase the flexibility of demand response resources in order to ensure that is the case.

What I would ask of the Illinois Commission and its staff would be that we

remain engaged with respect to these enhancements to RPM such that we can continue with the effective communication that we've had in the past and, to the extent that it's possible, for the Commission to support these changes that PJM is proposing through its stakeholder process and eventually at FERC so that we can ensure the ongoing efficiency and effectiveness of RPM in order to meet the long-term reliability needs of the region.

With that, I thank you again for having me here this morning. I look forward to the day's worth of discussion and any questions you might have. Thank you.

COMMISSIONER MAYE: Thank you so much for your presentation. I have a question.

Because this is obviously a regional issue, it's not necessarily a state issue -- this is RTO -- I'm wondering how often these conversations and communications are occurring in other states, particularly as related to PJM.

MR. BRESLER: From PJM's standpoint,

we have regular communications with the state commissions throughout PJM.

I was telling some folks earlier this morning, I was actually just at the Maryland Public Service Commission yesterday meeting with their staff and the staffs of other commissions on the phone as well discussing these very RPM issues.

So we have regular and frequent communications, and they do participate as well in our stakeholder process, like the ICC staff does as well, on the development of these rules.

So we certainly encourage and look forward to continuing that relationship.

COMMISSIONER McCABE: Commissioner Colgan, do you have a question?

COMMISSIONER COLGAN: Yes, I do. Thank you.

I was wondering, you know, looking at Slide 10 under "Cleared Installed Capacity," (Inaudible) that gas is going to be replacing productions in coal and demand response is on an increase.

So in combination with that, is the capacity really -- I mean, you said we were going to lose 20,000 megawatts in retirement.

Is the gas increase in combination with demand response going to be able to take over the space that's left by those retirements?

MR. BRESLER: Thanks, Commissioner Colgan.

The short answer to your question, from the standpoint of what we've been able to commit through RPM, is yes.

We've actually seen, between demand response and gas-fired as well as some other enhancements in new entry to existing units, if you will, that the new entry, in other words, the additions to the generation fleet, together with demand response has actually exceeded the quantity of retirements that we have seen, which, again, are primarily coal-fired units.

So the bottom-line answer to your question is yes.

Again, that chart that is up on the screen that you referred to, Slide

No. 10, is an installed capacity basis.

From an energy standpoint even out through 2016, 2017, and beyond, we still expect coal-fired energy production to exceed that of natural gas.

But we do see the penetration of natural gas increasing, which is actually going to make PJM's fuel mix more balanced because we are actually heavier on coal today from an energy standpoint.

With an increasing penetration of energy production from gas-fired units, it will actually serve to balance the portfolio a little bit more.

COMMISSIONER COLGAN: From the increase of gas, through the supply mix of gas, the demand response of renewables will eventually compensate for the losses.

But will it happen on a time frame that coincides with the retirements?

MR. BRESLER: Right.

From what we are seeing, again, through the commitments that we have made out through 2016, the answer to that question is yes.

These gas-fired units will be in place at or before the timeframe when these retirements take place.

COMMISSIONER COLGAN: Thank you.

COMMISSIONER McCABE: Commissioner Colgan, if you could mute between questions, that would be great.

Next is Richard Doying with MISO. He can probably address some of these same questions.

CHAIRMAN SCOTT: Before you get going, I want to ask Mr. Bresler a question. Sorry about that, Stu.

In one of your earlier slides -- I think it was Slide 3. I can't remember -- you talked about the declining generation and prices declining as well, which is fairly counterintuitive for most markets.

MR. BRESLER: Right.

CHAIRMAN SCOTT: What was the rationale that you guys described as to why that was happening?

The reason I ask is because you're ascribing most of the stability since that

time to RPM, but aren't there a lot of other factors that play into that as well?

MR. BRESLER: Well, yeah.

The capacity market we were operating at the time that -- where those prices were coming from was a relatively short-term market.

It only looked, really, a few months into the future from the standpoint of the start of an annual auction, but there wasn't even a lot of participation in the annual auction. Most of it was monthly and even daily.

So the prices were very short term, not far into the future. The reserve margins that we were seeing where they were declining to the point where they were actually dipping below the required reserve margins were two, three years into the future.

The problem was that the pricing that we saw was not reflective of where things were going. So that was the issue that we were seeing. I agree it's completely counterintuitive, but that's the reason why.

It was that disconnect.

CHAIRMAN SCOTT: Okay. I appreciate that.

Let me ask really quickly: You talked about demand response. I assume within that you're also taking distributed generation, again, under the broad umbrella of demand response?

MR. BRESLER: And energy efficiency, too.

CHAIRMAN SCOTT: Could you speak more specifically about distributed generation because we keep hearing it. We haven't seen it to the degree that we've seen it in other states.

Since that's coming, can you tell us how you forecast that going forward, not specifically but just more in general how PJM is looking at that?

MR. BRESLER: Yeah.

We don't necessarily forecast specifically distributed generation because to us distributed generation -- which I'm interpreting to mean sort of behind the meter.

We don't even see the generation -- we see it as less demand; right?

So to the extent that it comes in as demand response, we see it, again, three years ahead of time because it participates in the capacity auction.

So from the standpoint of a forecast per se, it really becomes how much is actually participating in the auction?

Now, if there are installations that are being done that are not demand response but are more of a 24-by-7, they can show in the energy efficiency potentially because they're 24-by-7 resources, although I wouldn't see a generator qualifying necessarily as energy efficiency.

So we rely pretty heavily on that three-year forward look as far as what we're going to see from a demand response perspective.

Beyond that, as far as forecasting the distributed generation, there's not much more we can get a handle on other than, again, communicating effectively with the state

commissions in our territory as far as what they're seeing and the utilities as far as what they're seeing as well.

CHAIRMAN SCOTT: So you would look at it more in terms of affecting the demand?

MR. BRESLER: Right.

CHAIRMAN SCOTT: Okay. Thanks.

MR. BRESLER: Thank you, Commissioner McCabe, and the rest of the Commission.

MR. DOYING: Let me also thank Stu for setting this up very well in terms of going through the definitions of some of the elements of capacity markets as well as the way some of those elements work in the graph. I'll get to that in a little bit more detail in a couple of slides here.

Within the MISO region, resource adequacy follows a lot of the outline that Mr. Rismiller provided for us earlier in terms of setting reserve margins, capacity and bilateral markets, centralized auctions as well as earnings, the resources we get from the energy market.

The resource adequacy provisions are pretty straightforward in terms of the objective or goal. The first is, as Stu noted, to make sure that you have enough capacity during emergency conditions, but you're also looking for reliable and efficient load service at all times.

So you don't only want capacity that's there in an emergency like emergency demand response -- and we have a significant amount of demand response in the region -- we'd like the market to send signals and put a planning process in place to make sure you get the right types of generation that are installed, as Stu said, in the right places in the footprint. So that's one of the objectives.

You also want to be able to respond to market changes that are due to a variety of factors, one of the most significant one now being environmental regulations.

With the EPA regulations, we see retirements of coal plants already occurring as well as some announced into the future. So that's something that you certainly also want

to address with your resource adequacy mechanism.

Finally, to the extent we are doing transmission planning, it's very helpful to have insight into what's going to be added and removed from the system in terms of generation resources.

It otherwise makes transmission planning challenging if you don't know where the generation is coming from with some fair degree of certainty.

Now, the process that we have within the MISO has some of the same elements -- in fact, I think all of the same elements -- that Stu and Mr. Rismiller walked through.

There's a determination of the planning reserve margin that's done through a reliability engineering analysis and is determined by MISO.

There's a forecast, and that's by location as well as by load-serving entity, and that forecast comes from our load-serving entities. It's validated by MISO, who currently looks at the methodology that's

being used and we're putting in place.

Currently, it will be in place by the end of next year is my expectation, an independent load forecast that we can use to compare to a load forecast that's generated by our load-serving entities.

We also have resource qualification requirements, and those are set forth: Demand response, all the existing thermal capacity, new thermal capacity, and importantly in the MISO region for wind.

Wind is a valuable resource. It's valuable in terms of setting very low energy prices. It's also highly volatile and variable. So it's difficult to determine -- actually, it's not difficult to determine.

It's important that you account for the variability in the output when you're assessing how much of that you can count on as a firm resource for meeting your resource adequacy targets.

Within the MISO resource adequacy process, after you determine the load, you determine the qualification requirements for

the generation. Then you require that all load-serving entities demonstrate compliance with that reserve margin. You may have multiple mechanisms to do that.

One would be through self-supply. So you show up as a load-serving entity and say, "I have my load. You have told me the reserve margin. I have under ownership or contract sufficient capacity to meet that reserve."

Alternatively, you can purchase either all or a portion of your requirements in a capacity auction that's conducted on an annual basis.

Now, I will note that we've got less history to report to you than they have in PJM. The annual market that we have in place now that is worked through with our stakeholders and implemented is a change from the prior auction construct.

Just last year in 2013 we ran our first annual resource auction. Not surprisingly, as was shown on the presentation that Mr. Rismiller gave earlier, prices were very low. When you have a 28 percent reserve

margin, not surprisingly, the market value of capacity is not very high.

28 percent is roughly double the amount of capacity that we determined is necessary to meet load on a forward-going reliable basis.

The next page goes through just a little bit more detail the elements of the resource adequacy mechanism within MISO, and I'm not going to go through this in detail since I talked through most of the issues here. I'll just highlight a couple points.

Under the reserve margin, MISO does calculate that for the region. The states, as was pointed out, have primary responsibility for resource adequacy, may have laws/policies in place where they would like to see either a higher or lower reserve margin.

That is within the jurisdiction of the states, and that adjustment can be made under the MISO tariff.

As I noted earlier, the demand forecasts are provided to MISO from the load-serving entities. They are in the best position to perform those forecasts based on their much

more detailed knowledge of the local area that they serve load within, although we do validate that.

Our validation process is going to change and, in fact, I think become more effective as we go forward beginning with next year.

If we look at the demand response programs, we've got about 8 gigawatts of demand response. That would be equally split between emergency demand response or actual demand programs where demand can be reduced as opposed to behind-the-meter generation, about 4,000 megawatts of that.

That's actually generation. Most of it would be small generators attached to industrial or commercial or small diesel generators, for example, and they also participate as a resource for resource adequacy purposes.

One of the questions that was asked was: What does the market mechanism look like within the RTO?

I thought what might be helpful here is

just to give you a high-level comparison between the mechanisms in MISO as well as all the other existing RTOs in the midwest and eastern portion of the country.

As you can see, there are lot of similarities, and there are also some differences in terms of the forward-looking period. MISO's is one year; New York is one year; PJM and New England are both three years forward.

In terms of the commitment period, all of us use a planning year. You can see that they are for the most part aligned.

In terms of the entity who is responsible for purchasing or self-supplying the load, in all cases it's the ultimate load-serving entity in the region.

If you look at the resource types that are eligible, they're the same in all regions other than in New York, which does not yet count energy efficiency as a resource; but otherwise, it's all traditional generation, demand response, energy efficiency as well as wind or intermittent generation.

Is there a self-supply option so that load can choose to supply their own needs rather than procure through an auction? The answer is yes. In all of the regions they have capacity markets.

Is there demand represented in the auction rather than bid in by the load? The answer is in all centralized markets, you have to represent the load.

If you're trying to have load bid to purchase in the auction, if the load does not show up at the level anticipated, the prices won't reflect the actual demand. So the supply and demand balance, as was talked about earlier, is important to maintain. You have to represent load in the auction.

You can see that's done in two different ways in the different markets. Stu talked about the sloped demand curve that is used in the PJM auction. That's used in both PJM and in New York. MISO uses a vertical demand representation of load, and that's also the case in New England.

The last element up there is a Minimum

Offer Pricing Rule. That is a market mitigation measure. MISO does not have one in place, and the other three RTOs do.

So this was an attempt just to give you a high-level overview of the similarities between the different regions.

One of the reasons that I thought this was important to put up here is it is the case that MISO has a very different regulatory structure in most of the states in the region.

Most of the states within MISO are very integrated, and they do elect in most cases to self-supply their needs. They do own their own generation. They have not divested them.

But for the rest of the load in the footprint, there is an auction in place, and it is the same auction that is in place in all other jurisdictions.

You can see in all jurisdictions, there are minor differences between the auction structures, and those differences have evolved over time and will continue to evolve over time in all of the RTOs.

In fact, FERC just had a technical

conference where they were examining resource advocacy markets in the regions, and these same elements were talked about.

Is there a best practices yet that we have identified for the various elements of the RTO markets? I think there was not a conclusion that came away from that market, but it is the case that all of the markets do have different attributes.

We are evaluating those over time to determine if there is something that in the long term we can say, "Yes, this is the model that works." I think we got there for energy. I think it's a matter of time before we get there for capacity market design as well.

COMMISSIONER McCABE: Is there a rough breakdown between self-supply and auction in MISO region-wide?

MR. DOYING: You know, currently most of the load chooses to self-supply, even the retail load within the region.

Most of the retail load -- and I can only speak for MISO and anecdotally for some of the other regions, and I'm sure Stu can

answer specifically for PJM.

Much of the retail load in deregulated states, load-serving entities choose to hedge their load obligation on a short-term forward basis. So on an annual basis, our experience has been much of the retail choice load does purchase -- or, rather, does self-supply rather than purchase in the auction.

MR. McCABE: Okay.

MR. DOYING: Going on to the last portion of the presentation, I wanted just to point out something that does make MISO just a little bit unique in terms how we're working with the states in the region.

As was pointed out with regard to the forward-looking period of an auction, the primary intent is to gain information as well as set efficient price signals looking out into the future.

We believe that it is also very helpful to get information from the load-serving entities not only looking out one year, two years, three years into the future but over a planning horizon, so currently up to ten

years, as to how they plan to meet their load obligation requirements.

We are conducting a survey with the Organization of MISO States going through and working with all of our load-serving entities to develop the load forecast for what they see is their long-term planning needs.

We have our reserve margin requirements on a long-term basis and then looking at the resources that are variable so that as you evaluate new additions -- and there are some that have been identified by load-serving entities within the region.

When you look at retirements -- and I noted there have been retirements announced within the region -- we can tell on a longer-term basis going out to ten years what the picture looks like in terms of resource adequacy on a regional basis as well as with the setting that we're undertaking now, we'll be able to look at a subregional basis because, again, the load is forecast on a local basis.

So you know where the resources are at,

and we'll be able to perform that analysis in order to get a good picture as to what that looks like on a long-term planning basis.

CHAIRMAN SCOTT: When will the results of that survey be out?

MR. DOYING: I believe the initial results of that survey will be out -- and I was talking to Mr. Berntsen about that. Next week sometime?

MR. BERNTSEN: Mid November.

MR. DOYING: Mid November.

It will take a little bit longer for the regional evaluation, but that will be out either later this year or very early next year.

In terms of the process that we used and the value that the survey provides, the analysis provides, is one that we were able to work with the states who, as we noted earlier when we talked about state versus regional views, all the states have different regulatory constructs, they all have different planning constructs, and they all have different evaluations that they want to

undertake within their state to understand resource adequacy within their state.

We also determined working with the OMS, one of the concerns we had was that most of the planning processes in states that do have formal planning processes look at individual utilities. They look at individual states. They don't necessarily take a regional view.

We thought that was important and valuable for the states to be able to have that regional perspective that you can only get through a regional role of all of the different plans out there.

So I think that information is going to be very valuable.

In addition to having the near-term next two, three, four years that are fairly well locked in, we've asked for confidence factors, run-load forecast, and new additions going out into the future. Again, I believe that's going to be very valuable from a planning perspective.

The survey, so far we've gotten very good response rates, in excess of 98 percent.

That would include from alternative retail providers. We're analyzing the survey responses, as I noted, to evaluate and determine and provide a region-wide perspective.

We're continuing to work with the states and the stakeholders to both validate the data, which is obviously important to do, and to address any concerns.

The types of concerns that you would have would be from generators about confidentiality of market sensitive information. You would not likely see information about their planned retirements, for example, published in the survey that would go out to other market participants.

So we'll have that continued review of the results, and, again, we would hope to have that zonal analysis that could be released publicly in the early part of next year.

And with that, I'd be happy to take any questions now or during the panel discussion.

COMMISSIONER McCABE: Are there any

questions?

If not, we'll go on to Dr. Bowring.

DR. BOWRING: Thank you. It's a pleasure to be here. Thanks for the invitation.

I'm going to take a slightly different approach to this, no slides, but I wanted to talk about some of the conceptual issues in RPM and some of the conceptual underpinnings of RPM and see where we go.

So Illinois -- as you know, part of the reason for the forum today is Illinois is in part within the broader PJM market. So the design and operation of PJM markets obviously has a direct impact in Illinois.

But in addition to Illinois' location in the very western part of PJM, interactions with the MISO market pose special challenges.

The details of the PJM capacity market design, some of the very nitty-gritty details, as Stu was talking about and I'll talk about in addition, have implications for reliability in Illinois, and that's part of what I want to talk about today.

But from the very beginning, we just need to ask the most basic question. So Stu and Randy covered this in part, but I wanted to go it from a slightly different perspective.

So the first question is -- and Richard covered it as well -- resource adequacy. So what is resource adequacy?

So the simple definition is -- the NERC definition is that you want less than one loss-of-load event, a pleasant euphemism for a black-out, less than one of those in ten years.

You want reliable electric service. We're talking about at the wholesale level, obviously, not the retail level. The retail level is a very different matter.

So how is resource adequacy achieved? Resource adequacy is achieved by having excess generation, by having more generation than you need to meet your forecast peak load, and to have reserve margins in the range of 15 to 20 percent.

As you heard from Stu and Richard, in

fact, some of them are a bit higher than that at the moment.

So what's the issue or why are we talking about capacity markets at all? The reason was alluded to by Randy, which is that the competitive -- when restructuring was undertaken, we went to competitive wholesale power markets, nodal power markets, in which generators make competitive offers and the market clears subject to transmission constraints.

What was not carefully thought about was revenue adequacy; that is, how much money does it actually take? How much do you have to earn in order to provide an incentive to invest in new generation? What does it take to have that market be what would I call "reproducible"?

So it's easy to run a market when you have a surplus of generation, but how does the market evolve from one state to the next?

Again, is the market internally reproducible? That's really the question.

So the problem arose and became clear in

PJM in the early 2000s that the energy-only market design was not going to produce a reliability margin adequate to meet the new standard.

And one of the things about energy-only markets -- and this has become very clear and I think an excellent debate happening in Texas.

One of the things about energy-only markets is they don't actually permit you to set reserve margin. Reserve margin is an output of the market, not an input.

It looks, from the analysis in Texas and from other analysis, that the reserve margin we're likely to earn from an energy-only market is well below the standards that apply.

So what really that means is that blackouts are part of an energy-only market response, and, of course, they would be. Without NERC reliability requirements, you would have more blackouts, and that would simply be considered part of the market response.

PJM and others have chosen not to go

that route, to continue to maintain relatively highly reserve margins. If you can do that, you directly have to address the fact that the energy-only market in the presence of that excess generation does not generate adequate revenues to incent new investment. That's the nub of the issue.

If you have a reliability requirement, whatever it is, one in ten years, 15 to 20 percent, that means you're building an excess supply.

From a simple economics perspective, when you have excess supply, it tends suppress suppress the price compared to the purely competitive outcome, and it means that there is not enough revenue to induce investment, the so-called "net revenue" or "missing money problem."

That's the reason we have capacity markets, but it's not the only -- capacity markets is not the only possible solution to that problem.

You can permit the exercise of market power, let people raise prices and get away

with it. Alberta is following that route. They're having some interesting experience with that. Whether it's successful or not, I'll leave it up to Alberta to say. I think they think it is.

You can do direct bilateral contracts. Every time you need capacity, you can have a bilateral contract between a utility and a generator. California is following that route at the moment.

You can go cost-of-service regulation. State by state, continuation of cost of service regulation, that's another way to maintain reliability. I would say -- Richard can tell us later if he disagrees, but I would say that largely describes the MISO situation.

You can deal with administrative scarcity pricing. PJM has a version of administrative scarcity pricing. Texas is attempting to see if they can get by with only administrative scarcity pricing.

Finally, you have capacity markets.

What we're really talking about is what I would refer to as a paradigm choice. It's a

paradigm choice between relying to the maximum extent on markets and relying on the more regulatory paradigm.

It's a regulatory solution versus a market solution. It's cost-of-service guarantees versus the risks associated with the market.

There are well known issues with the regulatory approach, and that's what really led to restructuring.

In my view, the best option is a combination of scarcity pricing and capacity markets with, hopefully, a greater emphasis over time on additional revenues from the energy market through scarcity pricing.

But the key thing to remember about markets -- it should be obvious, but it's still worth pointing out -- is that the market's investors take the risk, not ratepayers. Randy said this.

There were lots of actual losses. As a matter of fact, there are people in this room who are going to talk to you later probably about losses that occurred in actual companies

in PJM.

Early on, even from companies that remained viable, lots of those who rushed in to build brand-new combined cycles in PJM lost money; and those dollars would otherwise have been paid for by ratepayers.

So not only in theory but in practice investors take risks, not ratepayers, under market approach.

We also have incentives to reduce costs. We've seen a number of new projects, particularly in the eastern part of PJM, building new combined cycles where competition among developers and among original equipment manufacturers to provide generators to those builders, to those developers, has led to very remarkable improvements in technology, reductions in heat rates, significant improvements in unit efficiency, output, and so on.

So markets have both those benefits, and I think it's important not to underestimate them. It's difficult sometimes to quantify them exactly, but they very clearly have

strong incentive effects on investors.

In contrast, the regulatory approach obviously has guaranteed cost recovery, and, more importantly, there's no ability -- if you're in an area where the predominant paradigm is cost-of-service regulation by states, there's really no ability for merchant generators to compete, to build a new unit.

If existing generation receives its key revenue shortfall make-up from cost-of-service regulation, that's not available to merchant generators. Therefore, it's very difficult, I would say impossible, for merchant generators to compete.

In fact, part of the reason I think we saw Ameren sell their assets off and continue to see issues is precisely that, that it's not possible in a regime dominated by cost-of-service regulations to monetize the value of capacity.

So to have a competitive energy market that's sustainable, you need those additional revenues. So you need to cover all your costs.

The goal, I think, is a competitive energy market. Really, what this is about is the energy market.

I think sometimes we act as if the capacity market really is a stand-alone product and somehow is parallel to the energy market, but it really in fact -- the entire goal of the exercise is to have a competitive, sustainable energy market.

That's really the only purpose of having a capacity market, not because we like capacity markets -- we love all the complexity and the thousands pages of Attachment DD to the PJM tariff -- but because it facilitates the competitive energy in the market.

Nobody uses capacity for anything. Capacity really is something of an abstraction, but it is an essential way to ensure that we have adequate revenues and generators who produce energy.

I very much agree with what Richard said about it's not really about a couple of peak hours. It's about making sure we have an effective energy market. It's producing

energy at the lowest possible cost for customers year-round. It's not simply focusing on those peak hours.

The level of net revenue shortfall is very significant. The net cost of new entry in PJM is somewhere between $200 and $300 a megawatt-day. Those dollars have to be covered one way or another, one paradigm or another.

So it shouldn't be surprising when we see capacity market prices in that range. That's entirely consistent with the competitive outcome, it's entirely consistent with the incentive necessary to induce entry, and it's entirely consistent with the actual costs of building new generation.

So there are a couple of key elements in the PJM capacity market design. RPM is on there I wanted to talk about.

On the demand side, it's must buy. Every single megawatt of load must buy capacity. On the sell side, every generator must sell.

The PJM capacity market cannot work

without both of those being in place, must buy and must sell.

On the demand side, there's an administrative demand curve. Stu talked about that. Some slope is better than vertical. There was discussion about it.

The slope of the demand curve matters, but the key thing is it's the demand curve that represents 100 percent of load. It's a must buy, and there are no exceptions.

On the supply side, the same thing. It's must offer. There are no exceptions.

As Richard said, unless you have all supply and demand represented, you cannot reflect the underlying economic fundamentals, and you will not get to the right capacity market price.

But more specifically, what capacity means in PJM is it means a couple of very specific things. It means capacity has to be physical. Stu talked about this. It's critical for both demand side assets and generation assets, it has to be physical.

It's not a liquid and damages contract.

It's not a slice of the system. It's not any other financial construct. It has to actually be a physical asset which can actually produce energy or reducing energy demand.

Capacity has to be deliverable to load. This came up in some of the discussions about transactions between MISO and PJM.

By "deliverable to load," I mean that the capacity owner has to have invested in adequate transmission to ensure that on peak, the energy from those capacity resources can actually get to the load. That's key, effectively firm transmission.

The energy from capacity resources has to be recallable by the RTO in an emergency. So if the customers in PJM or MISO pay for capacity, the energy associated with that capacity has to be, in fact, under the rules is recallable by the RTO in times of emergency.

So when PJM had an emergency over the summer, the energy associated with those capacity resources were recallable.

Regardless of the nature of the sale,

regardless of the nature of the contract under which someone might have sold that energy, it is recallable immediately, instantly, and administratively by PJM.

Finally, there is a must-offer requirement. Again, this goes back to the very explicit link between capacity markets and energy markets. It's a must-offer requirement into the energy market.

If you're capacity resource, you have to offer your energy, I would say, at a competitive level. Generally, we do see that, although the rules don't actually say "competitive market," "competitive offer," but you do have to offer your full install capacity level. You have to offer all that capacity sold as energy today in the energy market.

In addition, the RPM market is forward looking, which, again, I think is key. It's three years forward. It permits competition from new entry. It's an essential part of the design. It's locational.

As Stu mentioned, there are market power

rules. The metrics for success in the PJM capacity market, really any capacity market, are, first of all, that you maintain adequate capacity. It's not just in aggregate, but it's also locational.

As you know, the PJM capacity market is very locational. The western part of the system for Illinois has very different prices, very different supply and demand conditions.

The face is very different now, the levels of uncertainty going forward than some of the other parts of the system to the east in PJM.

I think that the PJM capacity market has generally worked to provide adequate capacity, but there are some very significant issues with the design that still need to be addressed.

The second metric for success is that the capacity market prices have to be permuted to reflect the underlying economic fundamentals. They really reflect supply and demand conditions, and that's the key to getting reliability at the lowest possible

cost.

So just very briefly, some challenges. I've talked about these more extensively elsewhere, but some key challenges facing the design of the market are that, in our view, it's going to suppress the price. In fact, we've measured it.

So the first one, the 2 1/2 percent demand offset, demand curves have been shifted to the left by 2 1/2 percent. It suppresses the price by about 20 percent in the PJM market.

The inclusion of limited demand side resources, which only are required to offer 60 hours worth of reductions in the year compared to the 8,760 hours in a year that a generation resource is on call for, the inclusion of that also tends to suppress the price, again, another 20 percent.

So those two things by themselves have taken $4 billion to $5 billion out of the market, suppressing the price in a very significant way.

While it appears to favor customers, it

actually really doesn't. Price suppression in the short run causes exactly the opposite in the longer run.

One of the results of replacing -- and this has actually, in fact, occurred. One of the results of replacing actual generation with demand side is you can see events as we saw in ATSI over the summer, which, as you can see, energy price is being set by demand side at $800.

Almost all capacity resources that are demand side have a strike price of $1,800. Under the new PJM rules, they are permitted to set the actual energy prices at that level, and that will go to $2,700 next year.

There are a couple of key issues there on the demand side, the 2 1/2 percent under the definition of "demand side product."

COMMISSIONER McCABE: Just for our folks, a point of information, ATSI is the area around Cleveland; right?

DR. BOWRING: Yes. Let's see if I can remember what ATSI stands for. It's American Transmission Systems, Incorporated.

Particularly, it's the area right around the lake, right around Cleveland.

So a couple of other things. Again, Stu alluded to them, and they're in the process of being discussed in the stakeholder process.

It's key that demand side be physical. It's key that imports be physical and not simply promises and not simply speculation.

The market cannot work unless both those things are true, and I think the proposals that PJM made are good. I don't think they go far enough, but they're good and they're moving in the direction of tightening up the definition of what it means to be physical.

For better or for worse, in every auction we all collectively learn something else about some of the flaws or things we hadn't talked about in RPM; and every auction, as a result, gets better.

So I think RPM is improving. I think it has been critical to the success and reliability of PJM.

It's been critical to permitting PJM to

adapt to the very substantial levels of retirements and the very substantial levels of required investment for environment and the very significant changes imposed on the market by the C change that resulted from shale gas and the impact on the relative competitiveness of coal and gas.

It's also critical that internal plan generation resources as new resources also be physical.

Finally, on the supply side, it's important that the incentives to perform be strengthened. They should look as much as possible like they would look in an energy-only market.

There should be strong incentives to perform when demand is high, and there should not be payment if performance does not occur.

Just to wrap up, it's essential that the RPM capacity market continue to reflect the underlying market fundamentals. That is not happening now for a couple of reasons that I mentioned. It needs to happen.

So I'm looking forward to continued

improvements in RPM. We don't want to get to the point where market distortions actually lead to ad hoc fixes. We want to make sure we're addressing the underlying fundamental reasons and the fundamental changes that are required in RPM.

Again, thanks for the opportunity to talk. I was rushing to get through it all, but thanks for your time on a lot of complicated topics. Thanks very much.

COMMISSIONER McCABE: And you.

Will all of you be able to participate in the 3:00 o'clock roundtable?

Okay. We'll keep going, and, hopefully, we'll have a little time for some questions after some of the panels. We'll have a vigorous discussion at the 3:00 o'clock roundtable.

Panel 2, our next panel, will discuss resource adequacy from a variety of perspectives. Elise Caplan is the Manager of the Electric Market Reform Initiative with the American Public Power Association. APPA represents over 2,000 community-owned electric

utilities, many of whom participate in the MISO and PJM markets.

Dave Kolata is the Executive Director of the Citizens' Utility Board and will discuss the customers' perspective on this issue.

Kevin Wright is former Commissioner and Chairman of the Commerce Commission and now Executive Director of the Illinois Competitive Energy Association. He will provide perspective of Illinois' third-party electric suppliers.

And fourth, we have John Moore, who is a senior attorney at the FERC Sustainability Project within NRDC.

I'm going to start with Elise.

MS. CAPLAN: Thank you very much for having me today. I'm also going to be talking a little bit more big picture about the RTOs, specifically capacity markets.

So just a little bit of background on APPA. Commissioner McCabe already gave a little background on APPA. So I'll just kind of jump to the project that I've been managing for the past seven years, which is the

Electric Market Reform Initiative.

This was created in 2006 as a result of a lot of public power frustrations with the RTO markets. Some of these frustrations concerned high or volatile prices, difficulty obtaining long-term contracts, extreme complexity, and a great time-consuming governance process.

Over the past few years, we've been focusing a huge amount on capacity markets and concerns with those markets. So that's going to be the focus of my talk. Okay.

So the fundamental question that we're looking at is: Are capacity markets working? Are they providing needed resources and doing so at least cost?

PJM's Reliability Pricing Model, RPM, has a number of features that we see as problematic. It's been mentioned that the prices are very volatile. Its commitments are short term. It's three years forward, but then the commitment is only for one year.

We don't see price signals as being effective either in the locational marginal

pricing and energy markets or in the capacity markets, and there's logic to this.

In the capacity markets, once you see the signal and build, you're in the next year. The price is no longer there.

If you own a fleet of resources in a zone, it's really not necessarily in your financial interest to build a lot and bring down the prices. So there's kind of reverse incentives there.

So if you look at higher price zones and what generation or demand response has been offered, there's not really a correlation.

Each megawatt is treated equal. Like the energy markets, this is a single clearing price auction with the exception of some minor differentiations, demand response products.

But each megawatt, whether it's a brand-new combined cycle plant, demand response, a 40-year-old coal plant, is going to get the same price, and it's also going to get that same three-year period for planning.

Resources are very different. So what that means is there's not accounting for fuel

diversity, technology types, specific characteristics of the local transmission system. Things like that are not accounted for.

You're also going to have a situation where some new resources may not be getting enough certainty and enough of a price. Older resources may be overpaid. It's not balanced out.

As mentioned, PJM is a mandatory market. Everything has to flow in and out of it. If a utility owns a power plant, it's got to sort of be bid and purchased back out in the market, other than the fixed resource requirement, which we see as a very, very restrictive and not really a doable opt-out option.

For MISO, right now we don't really have a lot of problems with it because of the fact the pricing market is voluntary, it's a residual market outside of Illinois, it's mostly characterized by integrated utilities, and it doesn't appear that this is really the centerpiece of the resource adequacy

strategy.

So I think the fundamental kind of metric to look at when you're looking at the markets and the question of how they work is: What gets stuff built?

I did a study a couple years ago which I called "Power Plants Are Not Built on Spec," and I just took all the data on nuke capacity that came online in 2011, not really a readily available metric. I just had to do a lot of digging.

I found about 98 percent of the megawatts were either owned mostly by utilities, sometimes on-site at a customer, or subject to a long-term contract. 37 percent of that was public power or co-op ownership or contracts.

In PJM, if look at sort of the new megawatts that have cleared the base residual auctions, again, just digging around -- this is not a published metric -- I found about almost half, about 40 percent, that is under a contract or known -- and this is stuff that PJM is putting out as part of the success of

the auction -- some of it are either contracted for by states or public power. So that's kind of what is getting stuff built that we know about.

The next slide. So what I did was just -- really out of curiosity, I just looked at Energy Information Administration data, looked at new generation that came online in Illinois from 2009-2012, about 4,800 megawatts, just nameplate capacity.

A lot of wind. Almost half is Prairie State and Springfield's Dallman 4 plant. 84 percent of that new stuff was owned or contracted.

Coincidentally -- and I think this is a little bit unusual -- 66 percent was public power/co-op. You have Prairie State that's a big chunk of it.

You also have a lot of wind power signing long-term contracts with the Tennessee Valley Authority, which then distributes that to public power and co-op and the Dallman plant.

So that was a little unusual, but the 84

percent is not. That's pretty typical. So just remember, if something is built within an RTO, you really have to look at the financial arrangements behind what's getting that built. So that's what we know.

So next slide. This is a complicated slide because the Minimum Offer Price Rule, which has been mentioned briefly, is actually a very, very sort of troubling turn of events.

So if you start with the first few years of the capacity markets, they had a lot of concerns about how they were working, and as well, New Jersey and Maryland became very frustrated with the market.

Our members actually have been increasing their level of self-supply. They have stated this is publicly because they feel like the markets are just too unpredictable, too volatile. There's too many changes. They'd really rather see if they can start to self-supply more.

Similarly, New Jersey and Maryland saw that they have a lot of constraining zones. Capacity prices were very high, and stuff

wasn't getting built.

So under two very different governors, Maryland through the PFC, New Jersey through the state legislature, decided, "We were down in the markets. We wanted just to issue RFPs, have the distribution companies sign them, and we're going to get new natural gas plants built."

Of course, in any market that increased the supply; prices were high; supply increased; and then prices started to drop.

Dr. Bowring did a study predicting the drop in prices if all these new plants in New Jersey and Maryland bid in. Pretty significant, so lower profits.

What that meant was that a group of the merchant generators went to FERC and said, "Well, we need a solution to this problem of this new supply responding to high prices."

What they decided was to tighten the Minimum Offer Price rule. That was really in existence -- I know this is complicated stuff, but essentially a Minimum Offer Price Rule, like it sounds, says that if you, say, own a

plant or contract for a plant, you want to just bid it in as zero, you want to just be a price taker because you have your own site contract, now you may have a minimum price imposed on you.

Because things have to clear the auction in order to be counted for reliability, once you bid it in at a higher price, it may not clear. You may pay twice.

Now, a key part of the original Minimum Offer Price Rule that was carefully negotiated -- RPM was a product of a very long, kind of protracted settlement negotiated, and public power and co-op had sort of a guaranteed clearing of the auction for self-supply, basically just saying, "Okay. You're going to have these markets. You want to just be able to build your own stuff if we need to do so to serve our load at least cost."

That was taken out in this FERC docket. So you no longer have that as well. The states -- the reason New Jersey and Maryland did this -- also had an exemption from the

MOPR, as we call it, for any new resources needed for reliability. So that was also removed. These are negotiated provisions that FERC just kind of overturned.

So the bottom line is in this market, you now have kind of a regulatory solution to impede new entry; and that also sort of adversely impacts public power's ability to self-supply. I think that's my longest slide.

Next one. So what about MISO? We feel like we're looking at MISO and saying, "No. Don't do it. Don't do it," because FERC did approve the new capacity auction for MISO in 2012.

They rejected having a mandatory market. They rejected a MOPR. They included a good opt-out provision, but then this summer FERC has requested briefs on the inclusion of a MOPR in MISO, and that was a response to some of the rehearing requests.

So we are concerned about that. Like I said, MISO is a manageable, just a residual market. So we really don't want to see it go down that route.

Next slide. A quick look at the one MISO auction under the new construct. If you look at what was bid in as a zero price, that's really pretty much self-supply as a price taker and bid in under this opt-out provision.

Fixed Resource Adequacy Plan, you have about 91 percent that seems to fall in the self-supply category, some DR, and a very, very small percentage of positive-price offers where we're actually sort of bidding in and treating it really like a market rather than just bidding it at zero as a price taker.

So APPA has actually been working in the markets for a while. In 2009, actually, we came out with our first proposal. I actually have a few copies of it, our Competitive Market Plan.

What we said in 2009 was, "We don't think price markets are working. We think they should be phased out." We re-released that in 2011. We are okay if they are kept as a small residual market.

We really think that bilateral

contracting is one of the best means for resource adequacy. You can tailor the contracts in terms of resource, in terms of cost, in terms of length.

It is competitive because you can have negotiations. You don't just have everybody bidding and getting one price. The RTO would still set the reliability standard.

The tricky thing in the retail access states is are there enough parties outside of the parties who signed the contracts? So that's sort of the part we're trying to get sorted out.

We propose that the states, meaning the state commissions, would actually kind of determine optimum resource needs, issue RFPs for contracts with varying terms to avoid too much risk and to meet the needs of its resource. It would be optional for public power to kind of participate in these procurements or not.

I just do want to say quickly that we're not alone. Cliff Hamal, an economist at Navigant Economics, not exactly an anti-market

group, has actually recently proposed something very similar and said, "To phase out capacity markets, have all the LDCs sign bilateral contracts just for capacity, and keep the energy market still as something subject to retail access."

But he sort of has come around separately from us to a very, very similar proposal. So I just wanted to give him a little shout-out.

If there's no stomach for really, really phasing out capacity markets and doing this kind of stuff, at a minimum we really do want to see the self-supply, guaranteed clearing of the markets restored so public power can just go back to serving their customers and doing what they need to do.

So just briefly -- this was mentioned before -- FERC did recognize that there is a lot of concerns like allowing the capacity markets.

They did have a full-day technical conference. They requested comments by December 9th. So a lot of parties are going

to be filing stuff at FERC. It should be a very interesting docket.

I just want to close with one mention. I apologize. I'm in Illinois, and I mentioned somebody from New England, but at the technical conference, Commissioner LaFleur asked a bunch participants if they could start all over from scratch, what would they do?

And Robert Ethier from ISO New England said, "I would want to see a world with more robust bilateral engagement, more load-serving entities with long-term obligations. The market would be much more successful if you had that long-term counter-party to go with the resource side."

That's kind of what we've been saying and proposing. So I'll close with that.

These are posted. We have a link to all our materials that we put out. I'd be really happy to give you an e-mail or a phone call to discuss our proposals and any of this in greater detail, and I'll be here for the later session.

MR. KOLATA: Thank you,

Mr. Chairman, Commissioners. My name is David Kolata. I'm Executive Director of the Citizens' Utility Board. I appreciate the opportunity to speak with you today.

In Illinois, when you look at our existing capacity, when you look at load growth, and when you look at market signals, it doesn't appear we have any capacity concerns in the near term. I think that's true even accounting for the expected closures of a few more coal plants.

But, of course, things can change quickly in the energy industry, and it's always prudent to plan for the future. So I don't think we have any near-term reliability issues.

It is important that we have a comprehensive strategy going forward. For us, that comprehensive strategy must emphasize and prioritize energy efficiency, demand response, dynamic pricing, and distributed generation.

The reason for this is simple, I think. If we simply try to rebuild our existing

centralized system in the future, it's pretty much the end of the world from a consumer point of view no matter what technology you use. It doesn't matter if it's nuclear, if it's clean coal, if it's wind, if it's gas.

Trying to build our way -- or only build our way out of our future energy challenges will be enormously expensive, and you can see that in the debates that play out here in Illinois around certain plants, the Tenaska plant, for example, $4 billion estimated for roughly 600 megawatts of power. That gets pretty expensive pretty quick.

So I'm not trying to say that we shouldn't or won't have to build any new plants in the future. We will, of course.

What I am trying to say is that can't be our main priority if we want to maintain clean, affordable, and reliable electricity.

Instead, we must prioritize demand resources like energy efficiency and demand response, as these are our cleanest and cheapest resources, and prioritize innovative

pricing programs that provide consumers with an incentive to reduce peak demand and improve load shape.

I think the State has a key role to play here as we move forward with Smart Grid deployment.

If Smart Grid works well -- and we hope it does -- it's going to unlock new sources of megawatts, new sources of energy efficiency and demand response because with Smart Grid you're going to have more control over systems. You're also going to have much better data and realtime telemetry.

All of this allows for much more market integration of energy efficiency, demand response, and distributed generation. Smart Grid also allows for time-of-use rates and other forms of dynamic pricing.

We wouldn't want to see such rates be mandatory, although we may want to move toward an opt-out structure at some point in the future. We do think that dynamic pricing has a very important role to play in maintaining reliability.

So we want to ensure that time-of-use rates are both offered and, more importantly, that they're promoted to consumers so that people can find out about them, especially those who have a good change of benefiting from them.

So every year when ComEd and Ameren file their Smart Grid plans, these are the types of things that we'll be looking for:

Is more energy efficiency coming online?

Is more demand response coming online?

Is more distributed generation coming online?

Are more people signing up for dynamic rates?

And what are the growth rates in all of these categories?

If the growth rates are good -- and we think the ICC can play a key role in ensuring that they are -- then we will be well on our way, I think, to meeting our future energy challenges.

This does, I think, lead naturally to a discussion of energy markets because while

Smart Grid will enable a more demand response and enable more energy efficiency and enable better integration of distributed generation, enabling won't become reality without opportunities to sell those services.

I think right now it's fair to say that in MISO you don't really see effective ways for the demand side to participate. Some of that has to do with the fact that it is still dominated by vertically integrated utilities.

You see a lot of the innovation right now on the demand side. It tends to be companies like Viridity and EnerNOC, Compost. They're not really active in MISO right now because they have issues in doing so.

There may be some opportunities to work with Ameren on perhaps figuring out a way to get the demand side more integrated into MISO. We'd certainly like to see that and have more movement in that direction.

At PJM the demand side can participate. The rules aren't perfect, but they have gotten significantly better over the years. We

certainly appreciate that.

We don't want to see them go backwards, though, and I think we'll maybe get this in the afternoon. Some of the concerns expressed by Dr. Bowring, who I have great respect for, but some of it we wouldn't want to see go too far because we do think that incorporation of the demand side and distributed generation of the markets is extremely important and that the market, especially for energy efficiency at PJM, is not where it should be.

If we're going to start, in a sense, limiting DR because one could argue that it's only meeting 60 hours of the year, well, then we should look toward more base load demand opportunities like energy efficiency to handle that.

So I think that in general for us the State has a very key role to play as we move forward with Smart Grid. If it works well, whether it's directed to or not, it's going to address a lot of these questions.

We think that the IPA can also play a key role here with market development. That's

probably all I can say on that, but we look forward to the conversation.

Once again, thank you for inviting me here. I'll be happy to answer any questions as we go forward. Thank you.

CHAIRMAN SCOTT: I'll ask you one quick question.

I'm not saying that this is my thought, but I want to follow up on something that you said when you talked about time-of-use rates and not making them mandatory.

You set that up by saying time-of-use rates could be a way to shape peak loads, that you could provide lots of other benefits for that.

If that's the cheapest way -- making an assumption down the road that that's the cheapest way to do it, why not mandatory?

Why have it be opt-out if that's the way to best serve all the customers the cheapest?

MR. KOLATA: I think it's a good question.

One of our concerns if you make it mandatory is that in a state with retail

choice, if the ground hasn't been laid for this, if people perceive it as shocking or a shock to the system, they may flock to what would essentially be average pricing with maybe a risk premium that's a little bit too high, not to pick on Kevin's industry entirely. I didn't mean it to sound that way.

We want to get more people on dynamic pricing. There's no question about that. We've been strong supporters of the realtime pricing program. We think that's a great program. I'd like to see it expand.

It's probably not for everyone because you do need to be able to manage that risk. So we think that a TOU rate is a good sort of middle ground. We would like to see it offered and promoted.

I can definitely envision a scenario where as that starts to grow and people are more comfortable with managing their risk in this way, that we can move towards an opt-out structure.

I do also fear the short-term

consequences if we just put everyone on it. There is a reason why Kevin's group pushes for realtime pricing for everyone, and it's not because they want people to be on realtime pricing.

MR. WRIGHT: Kevin Wright of the Illinois Competitive Energy Association. We're a trade association of ten alternative retail electric suppliers that provide electric supply service and renewable products to industrial, commercial, residential and municipal aggregation customers.

I was going to say that my comments have been shortened because for once David Kolata and I are on the same page, except for that last remark.

Our interest, my suppliers' interest -- I'm going to approach this from a couple of different viewpoints and try to be clear with mine versus my association's, which is what I'm really here for.

But the take-away message I think I want to give to the Commission today -- and it was kind of defined in the opening remarks by

Commissioner McCabe and Commissioner Colgan -- Illinois I think really faces a unique -- no. It is a challenge, and that is being in two RTOs.

I'm not passing judgment on which RTO is better; but in terms of answering these gnawing questions about resource adequacy, capacity markets, seams issues, transparency, market rules, it only makes sense that Illinois ought to be operating in RTOs that are somewhat compatible, where the rules are somewhat similar so that all of our customers, whether you are a ComEd customer or you are an Ameren customer, are enjoying the totality of benefits that a wholesale competitive market can provide.

That's kind of the viewpoint of my association is we operate in both RTOs. If I had concerns to express in that area, it would be largely the difference in the capacity market constructs.

The real difference is in the constituencies that occupy both RTOs. Illinois as a retail choice state is at this

point, with some very minor exceptions and apologies, the only retail choice state in the MISO footprint.

That presents some challenges for the MISO management. It presents challenges within the stakeholder process at MISO. Having been there as a former OMS president and at the market start-up, I understand those very much.

So in short, my members do have concerns about the constructs, the market rules in that it is so much more difficult to operate in between two RTOs.

To go to Commissioner Colgan's and Commissioner McCabe's point, you know, are we getting the biggest bang for our buck in either of our RTOs and in both and walking away with a better understanding of the challenges that Illinois faces by operating in both of those RTOs?

To get a little bit more granular in terms of the purpose of today's policy meeting, I think the first question I would say, again, very similar to David Kolata's,

is: Is our State facing a resource adequacy problem? I would agree that we are not at this time.

Illinois is an exporter of electricity, the third largest in the country. I don't anticipate, based on what my suppliers are telling me since they procure from the competitive wholesale market and resell to our electric customers, any immediate concerns, although it does bear watching going forward.

How does Illinois currently ensure that it has the resources it needs for the future? Illinois has always been a champion for the competitive wholesale market.

As we all know, a fully functioning, well-developed wholesale market is absolutely essential to the success of our retail market.

The Illinois Commission and its staff from the get-go, on the movement of ComEd into PJM and Ameren into MISO, has been very proactive in trying to get those markets to the point that they can bring value and support the retail market here in Illinois. So I think continued vigilance there is

needed.

The RTOs I think do provide the essential price signals needed to develop resource adequacy, transparency in the marketplace.

The transmission planning function that both RTOs do I think is also essential to Illinois' retail market because oftentimes transmission development and planning can take the place of actual generation development. So that's important to stay on top of.

Where I do have some differences is in the capacity market constructs between the two RTOs, again, to bring back the difficulty, I believe, in my view and from what I'm hearing from my members, of being in two RTOs.

I would direct the Commission's attention in terms of next steps on resource adequacy and, after today's policy meeting, to take a very hard look at Dr. David Patton's State of the Market Report, which was issued in June of this year, and particularly regarding resource adequacy in the capacity market.

I direct your attention initially to the Executive Summary -- it's a pretty quick read -- and his recommendations.

Here's the problem and challenge that I want to bring out. According to Dr. Patton, the independent market monitor, there are two significant shortcomings that continue to undermine the efficiency of the resource adequacy construct in MISO.

One is the representation of the demand for capacity in the MISO planning resource auction, and that is the current and vertical demand curve in which he recommends something very similar to what is in the PJM system RTO of a downward-sloping demand curve in its place.

The second is the prevailing barriers to capacity trading between PJM and MISO.

These are not new issues. This has always been the challenge in operating in two RTOs, and the MISO Board and the MISO management I have great respect for in trying to move that market forward and trying to deal with and accommodate the constituency groups

in that footprint which, as we've said several times before, is overwhelmingly vertically integrated states.

It's a continual evolution of that market. I personally am pessimistic that it's going to get as far and as fast as we would like and something similar to PJM market in construct clearly because of the constituency groups that are there in the MISO market.

I raise this -- and it maybe is somewhat evident. I attended the MISO Annual Stakeholders Meeting this June of former OMS presidents, largely taking a look at the market start-up in MISO and, you know, kind of where we started and where we are today.

One item on there was resource adequacy in capacity markets. From my viewpoint, speaking, again, from my viewpoint, not representing anyone else, Illinois favors a downward-sloping demand curve and that we ought to be looking forward three to five years to ensure adequate pricing, capacity, and resource adequacy.

My fellow panelists immediately but

politely rebuked that notion. I say that because we're all personal and professional friends, but it reflects the regulatory viewpoint of those states, Wisconsin, Missouri, and Michigan in name only since it is constrained by a 10 percent cap for retail choice.

It was largely kind of "There Illinois goes again, that noisy retail choice state." So I'm pessimistic that in that footprint with those stakeholders that we're going to get there very fast, and it is just a continuing challenge that I hope we can get to soon.

But that's my take-away is the challenges that I think Illinois faces and getting a reliable and highly predictive indicator of resource adequacy and capacity. I believe it's going to be an ongoing challenge.

With that, I'll draw my remarks to a close and be happy to take questions at the appropriate time.

COMMISSIONER McCABE: John?

MR. MOORE: Thanks very much,

Commissioner, Chairman, fellow Commissioners. I'm John Moore. I'm with a group called the Sustainable FERC Project.

The Sustainable FERC Project is a coalition of organizations, environmental organizations primarily, including the Environmental Law and Policy Center, NRDC, National Resources Defense Council, Sierra Club, Wind on the Wires, and others.

We have been working for over a decade at FERC and at regional transmission organizations throughout country and now increasingly in the Southwest and non-RTO regions in the West as well to promote low-carbon, cleaner, more efficient energy and grid solutions.

Our focus is FERC and the RTOs. We're pretty single minded about that.

I appreciate the opportunity to speak here today. I'm based out of Chicago. I'm a former senior attorney at the Environmental Law and Policy Center and just joined the FERC Project a couple years ago.

Let me start with a high-level overview.

It's getting close to lunchtime and probably past lunchtime for many of us. I've got two points, both related to what Randy Rismiller teed up at the beginning when he referred to or at least implied a possible paradigm shift in the industry and in our resources.

Two elements of that paradigm shift that the FERC Project and its allies are very interested in are, first, valuing the demand side and, second, recognizing the increasing importance and significance of wind and other renewable energy resources, solar, biomass, et cetera.

Those two kinds of resources, demand side resources and wind, solar, other renewable energy resources, are gradually growing in importance. They have been in the background for a long time, especially on the demand side, with the exception of demand response at PJM.

But as David Kolata just discussed in relation to the importance of Smart Grid in Illinois, we're going to see more of them in the future.

Certainly with wind, that has been growing significantly through State renewable energy standards throughout the MISO and now increasingly in the PJM footprint.

I think one day last year we had over 25 percent of the energy, I believe, or close to that in the MISO footprint at one time last year was supplied by wind energy. So it can be very significant, and it's going to get a lot larger.

So I would say as we look at resource adequacy, as I get a little more into this, we need to think of resource planning at the state level, such as it occurs through these state energy policies, and the RTO planning combined with the markets that we've been talking about is all feeding into overall resource adequacy.

I would also suggest that the Illinois Commerce Commission delve a little more deeply into these issues with both MISO and PJM because it's in the State's interest to do so starting, for example, at a very specific recommendation around submitting annual

information requests of some sort to both RTOs to get a very specific handle on how much demand side and renewable energy resources are actually occurring in Illinois through the Regional Transmission Organizations to give you a better idea of what the potential is and where the gaps are.

For example, is all of the energy efficiency that is occurring in Illinois actually showing up in the PJM capacity market?

Is it showing up in the MISO long-term planning process? And if not, why not?

So if you get that kind of specific annual data, then you'll be in a really good position to be able to coordinate more closely with both RTOs and help improve their planning markets to serve Illinois' needs.

With that, just a couple more minutes. Let's go back to the pessimist/optimist point. I think Kevin already referred to at least a couple of these.

From our perspective, in addition to the first two bullet points around the different

markets and the different approaches to resource adequacy, we're concerned about the relative weakness of demand side showing up in the MISO markets and in planning, along with some of the concerns we have in PJM, especially around demand response.

As Dave already suggested, we're kind of aligned pretty closely with the CUB on that point.

We're also concerned because despite the existence of numerous seams between the regions, there are very interregional projects. I would describe it almost as trench warfare sometimes in what's happening or not happening at the seams in terms of progress there because of the different markets and the different planning.

I think some progress definitely is being made, though, there. That's to commend both RTOs for doing that.

Now, the optimist in me says, "Look, we've got some FERC orders with the FERC project" -- so I'd like to talk a little bit about what FERC says -- "that strongly

encourage regional planning and better alignment of state needs with the RTO policy priorities and resource adequacy, the increasingly visible and maturing demand side that I've already referred to, more natural gas supply, more wind and other renewable energy resources and the fact that the EPA mercury and air toxic compliance is on track with very few of these out-of-market payments made to coal generators.

That's good, and I think that also sets us up for the future with compliance with the new carbon standards when they come out for existing power plants.

I think, by the way, with the energy efficiency demand response, the demand side will also become more valuable in helping to establish and get compliance with those standards.

So a couple of key points, four basic points in a little more detail here.

First, our allies support maximizing the use of demand response, energy efficiency, and, yes, even generation at times in planning

in addition to the traditional transmission alternatives that RTOs typically look at.

That's required under Order 890; and with the advent of Smart Grid in Illinois, it's going to be more critical to be able to rely on or at least identify where the demand side can help meet system needs more cost effectively than transmission solutions.

I think some of the framework is in place. It's happening to some extent in PJM but mainly through what happens in the capacity market and how demand side resources show up in the capacity market.

We think more can happen with more direct coordination with the states like Illinois, who regulates the demand, who has the programs around energy efficiency portfolio standards and the State RPS and other Smart Grid programs.

We also want to be able to be certain that all of the energy efficiency that is reflected in the load forecast actually occurs, and we're not yet confident that actually does happen right now.

Whether in MISO or PJM, I think the answers can be different depending on what's happening.

I would say, stepping back again to Randy's presentation around potential capacity shortfall in MISO in the future, these non-transmission alternatives can help meet whatever capacity shortfall needs exist in combination with what I think is an excellent first step in the MISO State Survey.

We are very encouraged and support MISO's survey of all of its states. We think that's a good first step in starting to get a better handle on how to use the demand side solutions to help meet transmission system needs throughout the Midwest.

Second, we'd like to see more demand response and energy efficiency in the markets. MISO, there's very little in the energy and ancillary service markets now in part because of lower prices but in part because throughout most of MISO's footprint, demand response can't really participate through these demand response providers because of state laws

preventing them from doing so because most of these states are still very integrated, regulated states.

Again, what David Kolata just said about the potential for more demand response in Ameren, that we agree with because Illinois isn't still an IRP. Ameren probably has the largest load area in MISO where we could look to more demand response occurring through the markets and other mechanisms.

I think that in PJM, in addition to the concerns about overrestricting demand response, we think actually even more energy efficiency should be showing up in the markets.

In ISO in New England, for example, over 4 percent of the total capacity obligations are met through energy efficiency resources, and in PJM it's only about .7 percent, less than 1 percent.

I do think that here in northern Illinois, we have a lot of ComEd supported energy efficiency resources in the market. That's good. There's probably more to be

tapped into there.

I also think the way the Illinois legislation works should be a model for other states to get more energy efficiency resources into the auction. So that's good.

We also like the idea that PJM looks like it's moving towards more storage or allowing for energy storage to bid into the capacity market.

Two more comments. Strengthen Interregional Planning and Improve Cost Allocation. We believe that with the additional and growing supply of wind and solar resources and for other reasons, there is a greater need for true interregional planning. We're not seeing enough of that between the two RTOs now in a meaningful way.

With the advent of Order 1000, it provides some additional encouragement but not a lot to make that planning occur. So I think that Illinois, you know, is in a perfect position to help move PJM and MISO along to develop best practices and improve that coordinated planning.

I know NIPSCO has complaints before FERC on this issue. Wherever that goes, I will say that it identified what we think are a number of best practices around coordinated planning, similar models, similar time frames, similar inputs, and helps to reveal the value of more projects.

I would finally point out on this that PJM just a couple weeks ago did a draft wind study showing that 100,000 megawatts of wind and solar, both resources, could be successfully integrated into the PJM grid with resulting lower overall production costs.

That's only at about 30 percent of total resources. We think it could go much higher, but the point is that integration costs are entirely manageable, and you do get overall lower production costs because you have wind and solar spread out over a large area.

Of course, it's a free fuel resource. So whatever additional costs you've got for more transmission and other costs are more than offset because of the fact that the fuel resource is free.

Finally, I think I've already noted that we believe that the first round of environmental standard compliance occurred successfully, first going back to Illinois with the mercury standards where that occurred without too much disruption and, I think, successfully and then now with the US EPA mercury and air toxic standards.

We think that in the next round of compliance with carbon standards, Smart Grid, energy efficiency, demand response, distributed generation will all become more important in helping utilities meet those standards.

I appreciate the time to speak here, and, hopefully, you'll have some questions either now or after the break.

COMMISSIONER McCABE: Questions?

COMMISSIONER COLGAN: I have a question.

COMMISSIONER McCABE: Go ahead, Commissioner Colgan.

COMMISSIONER COLGAN: The issue came up, I think, just about the differences

between MISO and PJM and the fact that, all in all, (Inaudible) that RPOs and how that response was complicated in terms of juggling all kinds of -- (inaudible).

THE REPORTER: I can't hear it.

COMMISSIONER McCABE: Don't worry.

COMMISSIONER COLGAN: We've been trying to chip away at that in terms of making sure that there's good communication between Illinois and the other states.

Kevin, you referred to kind of a complaint that has come up where it sounds like Illinois is (inaudible).

I think that's because the other states aren't necessarily doing forward planning of what the situation is that we have and certainly not enough to understand what goes on in their own state without trying to figure out what's going on in other people's states.

But it seems like the fact is that we are in two different RTOs, in one of those RPOs Illinois stands out as being unique.

Rather than look at that as a negative,

if we could look at that as positive and see if Illinois has some unique contribution that we could be making into MISO just because we are unique in that footprint.

So, again, that's my question. If anybody has ideas about that, I'd be glad to hear those and maybe not even limit that request to this discussion but out into the future as people may think through this and see that there are ways that Illinois can contribute and participate in MISO and OMS in a very constructive way.

I guess I'm interested if anyone has any comments on that.

MR. MOORE: John Moore here.

I think that one area is in Smart Grid in demand side.

Especially with the Ameren programs and the other programs that exist or could be developed, I think that Illinois really is a leader in the Midwest among MISO states. Minnesota is also very good, but Minnesota is a regulated state. So that's one area I would point to.

I would also say I wouldn't -- Commission Colgan, you know this far better than I do. I wouldn't necessarily wait for all of OMS to get behind you on any of these particular initiatives.

I enjoy working with OMS very closely on some issues, but I think sometimes the squeaky wheel can get results.

MR. KOLATA: This is Dave Kolata.

I basically agree with what John said. I think there is an opportunity, especially with Ameren. At least Ameren Illinois, it looks like they're getting out of the generation business. That may open up some strategic possibilities there.

MISO will never be, I think, a perfect fit given that it's a regulated state dominated. There are just big, huge policy differences between what you can do between both.

I do think that there could be some potential opportunities around the demand side, around energy efficiency, around distributed generation related to Smart Grid

that we could have a good opportunity to pursue.

MR. WRIGHT: I agree with John and David, but I also caution. I don't mean to sound so negative, but it's reality. Working in the OMS is very, very difficult.

It was difficult when I was there just getting them to agree that a MISO market start-up actually would be a good thing for the retail markets.

I think they were a lot more cooperative and sensitive -- I think we tried to be a lot more sensitive of each other's regulatory regime. I just kind of wonder if that same willingness and cooperation exists today. Increasingly, I'm being told that's not the case.

So I don't want to be terribly pessimistic. I just want to be realistic that Illinois is in the middle of two RTOs that have some different ways of going about implementing the market.

I guess I would say this: I think the Illinois MISO marriage is growing increasingly

incompatible. I don't think it's time for a divorce, but it certainly warrants some intensive counseling rather sooner than later. We are the linchpin in that market.

COMMISSIONER COLGAN: I appreciate your comment.

I think that it's really important, even in following with your metaphor there -- I think you have to (inaudible).

I think that arguing the differences is one way to go, but trying to find common ground is the way that it should work.

I think that's what our focus has been in working with the different states. Every state has its own personality in (inaudible).

I think moving it away from just arguing about "My state is better than your state," moving it more towards "My state is unique in other things that we can share and do with you," that's helping to move forward.

CHAIRMAN SCOTT: Let me follow up on the interventin stage here, too.

Does 1000 provide any help here other than just kind of on paper the requirement

that people will talk and try to get along?

Is there anything really in terms of teeth that makes 1000 help here?

MR. MOORE: John Moore here.

1000 is very good on requiring RTOs to consider public policy requirements, which we think very broadly include integrated resource plans in those states that have them, RPSs, energy efficiency portfolio standards, et cetera.

FERC hasn't interpreted as strongly as we would like on some of the cost allocation issues, especially interregional cost allocation. So that's where it's a little less than desirable.

I think on interregional planning, what it does emphasize is trying to harmonize differences.

FERC was walking, obviously, on several lines in not going as far as we would have liked, but, you know, MISO and PJM already had a joint operating agreement and a planning agreement that in some respects did go beyond what Order 1000 required. So that

was good.

What we don't want to see happen -- and you referred to it -- is Order 1000 becoming paper compliance. Our view is that that's kind of what's happened in a lot of respects with Order 890 requiring, among other things, comparable consideration of nontransmission alternatives to transmission alternatives.

One of the reasons has been this disconnect between Federal jurisdictional transmission planning and state jurisdictional, you know, other nontransmission resources.

So that's where we think the states just have to push a little more.

CHAIRMAN SCOTT: John, one more quick one to follow up on something that you said.

In terms of GHD compliance with the 111(d) regulations as they come out, are you talking about just in general it can happen because the more you have, obviously, the less traditional generation you need?

Or are you talking about it more as a working part of the State plan with EPA using the EE as a compliance mechanism?

MR. MOORE: Yes, absolutely, using the energy efficiency as a mechanism and other flexibilities that we think ought to be in the compliance.

CHAIRMAN SCOTT: Thanks.

COMMISSIONER McCABE: Any other questions?

Okay. We're going to break for lunch. There is a room near the reception area where the panelists can go if they need to make phone calls or hang out for a while.

If folks won't be returning for the roundtable but have questions, give them to Cameron. We'll try to work them into the roundtable.

Also, for those from out of town, there's any number of quick places to get lunch almost any way you leave the building. I think there's some lists on the table in the break-out room.

So thank you very much, and we'll see you soon.

(Recess taken at 1:05 p.m.)

AFTERNOON SESSION
Thursday, November 7, 2013
2:00 p.m.

COMMISSIONER McCABE: We'll get started again.

Just as a little added incentive for the afternoon, there's some chocolate outside the door to help you make it to the roundtable.

Our third panel is Resource Adequacy from a Generator's Perspective. We will hear from several generators in Illinois who operate in one or both RTOs.

Dean Ellis is Managing Director of Government Affairs at Dynegy.

Reem Fahey is Vice President of Policy and Market Operations at MidWest Generation, which is part of Edison Mission Energy.

Shawn Schukar is Senior Vice President of Trading and Marketing at Ameren Energy Resources.

Jason Minalga is Manager of Commercial Analytics and Regulatory Affairs at Invenergy.

I'm going to start with Dean.

MR. ELLIS: Thank you, Commissioner

McCabe, Commissioners, and Chairman.

I definitely appreciate the opportunity to come today and talk about this important topic. We were remarking at lunch. So far I think it's been an excellent discussion, very informative, even from our side of the business. Again, thank you.

With my first slide, I'll give the obligatory advertisement for Dynegy. Actually, it may help put some of our comments in context.

Dynegy operates, as I like to say, from Bangor, Maine, to San Diego, California. So we have the advantage of operating in all of the restructured states and regions but for Texas.

In addition, we currently do operate on both sides of the proverbial RTO/ISO fence here in Illinois. We have a Kendall facility in PJM, and the balance of our portfolio in Illinois is in MISO.

We're also currently under contract with Ameren to purchase five of Ameren's Illinois assets. So I threw those up there just if

it's of any interest or use. It does illustrate a couple of broad points.

Dynegy will become very Midwest centric upon closing this transaction. We will have nine plants totaling almost 10,000 megawatts in Illinois.

With the next slide, I'll start with some of the fundamental tenets of resource adequacy, and I'll try not to belabor or reiterate a number of the points that were made this morning.

Again, I thought it was very informative, and I think a number of points were very well illustrated and discussed.

So I was going to just remark that there's two fundamental or two basic metrics of system reliability, of course, transmission security and resource adequacy.

In the old days -- I called it "the good old days" because I'm now an independent power producer. In the old days, vertically integrated utilities did the integrated resource planning, the IRP.

They had a generation group that ran

production cost analysis and ran the studies out 5, 10, 20, in some cases 30 years, and then the utilities would, of course, go out and construct the generation to meet their load expectations and load profiles.

Of course, today in the restructured markets, the resource adequacy part of the equation is purchased in the market.

What we believe and what we have seen is that the markets do lead to efficient outcomes. It doesn't matter whether you're building small computer tablets or electrons. Markets lead to efficient outcomes. They do reduce costs to consumers. We have seen that in several of the regions.

Perhaps -- and this was mentioned before -- most importantly, the investment risk is shifted from captive ratepayers to private investors.

I don't have a bullet here, too, but it was also mentioned before. The wholesale competition is an integral part of retail choice, which a number of consumers have expressed an interest in.

With regard to either cost of service or market rates, it's all about cost recovery, of course; and as a generator, we really only have three ways to recover our costs. One is, of course, the energy market, and there's capacity market, and the third is the ancillary services.

So if we're missing one of those pieces of the equation or if one is not providing adequate revenue, then, of course, that puts a severe financial strain on our business model, as we are experiencing in a couple of the markets.

The markets do provide adequate revenue, again, as we have seen in a couple of the markets. They do provide adequate revenue. They do provide proper signals where the markets are properly designed.

On the flip side, all their inefficient, non-environmentally complied generation is retiring, as it should in those markets. Poorly designed markets, as mentioned again this morning, are not providing the adequate signals.

I can remember when I first came into the business, everybody said nuclear plants were too cheap to meter, and now we're seeing nuclear plants too expensive to operate.

So the take-aways that I just would like to stress is that properly designed markets have proven to be successful, and State-sponsored or subsidized supply is not necessarily needed.

Continuing with the next slide and the fundamental tenets, with regard to environmental considerations -- and I realize that was one point that the Commission asked us to touch on -- Dynegy and several other entities in the State have made significant investments in environmental compliance specifically to meet expected CSAPR, MATS, and the Illinois MPS and CPS regulations.

This investment has totaled over $1 billion for several of these companies each.

With regard to the capacity market and resource adequacy, these resources that have made such significant investments in Illinois

in the asset shouldn't be penalized for those investments.

There was some discussion before about the disparity between the cost for new entrants compared to existing generators and older generators. The point here is that even the older generators still have a pretty significant capital requirement.

Just to make one point, too, with regard to the rules, I picked this one example, but it is very important that the markets do be designed correctly.

There's an issue right now in MISO where some of the non-environmentally compliant generators are perhaps going to get a pass in the one-year capacity obligation. Again, with regard to environmental considerations, it is very important that the generators are treated with some equal regulation.

With regard to the direct subsidies to the energy market, as I mentioned, there's three parts of the cost recovery equation; and with regard to the energy market, we're seeing extreme distortions caused by presumably the

direct subsidies to the renewables, specifically the Federal wind production tax credit.

Our industry receives several subsidies up and down the stream; but when we see subsidies that are directly in the market, when subsidies pay for a product even when the price signals are saying that the product is not needed, it does cause extreme distortion, putting further pressure, again, on that cost recovery equation.

Also, a number of these distortions may be very good for consumers in the short term, but they can cause long-term pain.

Another fundamental tenet that we discuss at Dynegy is the procurement timeline for capacity markets and resource adequacy.

Again, in what I call "the good old days," the vertically integrated utilities planned 5, 10, 20 years out, not unlike the IS's currently. They do, I believe, planning on a 5-year basis typically at a minimum, sometimes 10 years out.

Yet in a number of the markets, the

reliability product is only procured in either a one-year increment or, worse yet, simply months before the start of the obligation. So there's this extreme mismatch between planning the system reliably and actually procuring the product in either reliability needs.

What you take away again in this slide, as I show, is that markets and environmental regulations, they can coexist. They have proven to coexist if the market is designed appropriately.

The next slide, I threw an illustration up of a vertical demand curve compared to a sloped demand curve. There was much talk about it this morning. So I won't again reiterate a number of points that were made, but hopefully you find this to be a good visual illustration of the problem that was discussed this morning.

So a vertical demand curve, as you can see, it's binary. In the case of an oversupply, you have extremely low prices. When it's undersupplied, prices can spike and go extremely high compared to a sloped demand

curve that provides more stability not only for the supply side but also for the demand side, that is, the generators and the load.

We feel that the ideal construct is a sloped demand curve, as shown there and as does exist in PJM in New York.

Some other considerations that we'd like just to touch on briefly, transparency, again, as I mentioned, the two basic metrics for system reliability are transmission security and resource adequacy.

Occasionally transmission security intersects in the resource adequacy area, and reliability contracts are necessary to secure the transmission system.

In the case of reliability contracts, it is imperative that they be issued in an open and transparent manner.

Another topic is portability, that is, the ability to transport capacity across markets and regions, and we definitely support portability from a consumer standpoint. It adds liquidity to the market. From a supplier standpoint, it adds liquidity to the market.

But it is important that the rules be aligned across the different markets. Portability doesn't make any sense if the two sets of market rules aren't clearly aligned. It can lead to a lot of distortions in the market.

With that, at the end of my presentation I included some background material. I'd be glad to take questions.

COMMISSIONER McCABE: Can you expand a little more on your transparency comment?

MR. ELLIS: Sure.

Again, occasionally it becomes necessary to issue a supplier a resource adequacy or a reliability must-run contract it's called in some markets.

It is important that the evaluation take place in an open and transparent manner so that all market participants, both on the load side and on the supply side, can effectively evaluate why the need is out there, what's driving the need, and how the need could perhaps more cost effectively be resolved in the future.

COMMISSIONER McCABE: Okay.

MS. FAHEY: Good afternoon. It's a pleasure to be here. I want to thank Commissioner McCabe for inviting me.

I'm just going to spend one minute to explain or introduce you to Edison Mission Energy. We're headquartered in California, but we have regional offices in Chicago and Bolingbrook.

We own or lease 40 operating facilities. EME's share is around 8,000 megawatts. It's not really a well-known fact, at least in Illinois, that we actually are one of the largest wind portfolios in the US. We own about 1,700 megawatts of wind facilities, 30 projects in 11 states.

I know the Commerce Commission is familiar with Midwest Generation, which is our largest subsidiary that operates 4,300 megawatts of coal-fired assets, and we have four generating assets within Illinois.

Edison Mission Marketing & Trading is based in Boston, and we perform hedging and asset management. As you may know, we are

undergoing financial restructuring. We have maintained a normal business operation throughout the process.

On October 18th the company announced a proposed sale to NRG Energy. It is still pending regulatory and Bankruptcy Court approvals, and we're targeting to close by first quarter of 2014 but no later than end of July.

One of the questions that the panelists were asked to opine on is whether we have resource adequacy both in the short term and the long term, and I'm going to focus my comments on PJM because that's where our assets are.

Due primarily to PJM's Reliability Pricing Model, which in our opinion is a well-functioning market, it needs a few tweaks, but it's the best market when compared to all the other capacity markets out there.

It's resulting in very healthy reserve margins. The last auction resulted in a 21 percent reserve margin, which is 5 percent higher than what the target is.

There is vigorous demand site participation. There's over 14,000 megawatts of demand response. That clears with 9 percent.

Just to put things in perspective, in the sort of the good old world, when you had vertically integrated utilities, demand response was always less than 1 percent.

So to have roughly around 9 percent participate in PJM is a testament that the market is working well. There's also over 1,000 megawatts of energy efficiency.

Another measure of a well-functioning market is robust new entry. There is over 28,000 megawatts of new generation that either already entered the market, started construction, or announced entry.

The other sort of robust participation has been through imports, mostly from MISO but other neighboring regions to PJM. In the last auction, the imports doubled. So now we have a total of over 7,000 megawatts of imports.

I think it's questionable to say that we're going to have resource adequacy in the

long term, and primarily it's because the market is going through some fundamental change.

The first one has to do with renewable public policy initiatives, and I know Dean touched on that a little bit.

So let me start by saying it is a very good public policy initiative, but, unfortunately, there's been unintended consequences to that, which is, in essence, we're seeing many hours of negative energy prices.

That just means that if you're a generator, you have to pay somebody to take the energy that you produce. So that's usually a red flag that we have sort of potentially an operation problem.

The negative energy prices, they continue to exacerbate generation margins. So that's very problematic in markets like California where they have 33 percent renewable targets. It's not such a big problem here, but it is one of the drivers for sort of inadequate return for many of the

generators.

The other one is the abundance of shale gas. It's a game changer in the market. Record low natural prices in gas is causing a significant decline in the amount of coal-fired generation that's been clearing the auction.

Mr. Bresler talked about this in the morning. In the last RPM auction we saw a fundamental shift. So now PJM has in the 2016-2017 time frame 15,000 megawatts more gas than coal.

It's in regions like Illinois and Ohio and Virginia where this is, in essence, coal country. 10,000 megawatts of coal assets did not clear the last auction.

Obviously, the Federal EPA and State environmental policy is causing old, small, inefficient power plants not to survive and to retire, and that's probably the right outcome if they cannot afford the environmental upgrades.

The other key factor that not many people talked about is that on the demand side

we've seen very flat growth for three reasons.

One is the economy, but two other reasons are that we see a lot of industrial load manage their consumption much better. It's primarily because of RPM because if you manage your consumption during peak hours, then you don't have to pay for a capacity payment.

In addition, there has been a lot of energy efficiency and implementation, which is causing a flat demand growth.

Dr. Bowring addressed the issue of energy markets. So when we look at resource adequacy, you can't just focus on capacity because typically 25 percent to 30 percent of the revenue only comes from capacity. The vast majority of the revenue that the generators get is from the energy market.

We are not seeing meaningful price signals even when warranted during scarcity pricing, and there is a lot of action that the dispatchers take that is not reflected in price.

So the punch line here is that we

believe that many of the existing resources could fail to recover their going-forward cost, and this could result in disorderly retirements.

So in regards to what we need to do to inform the markets -- and, again, my remarks are focused on PJM -- the first one, which both Dr. Bowring and Mr. Bresler addressed -- is that we have to make sure that the imports that PJM accepts respect the physical limits of the transmission grid.

I believe that PJM allowed way too much generation to be imported into PJM that probably exceeded their import capability.

The other problematic issue is that there is a lot of capacity that gets put in the markets, and Dr. Bowring did talk about that at length.

So typically PJM holds the auction three years forward. The price is healthy, but the incremental auctions have very low prices. So it made it an incentive, whether it's existing generation or demand response provider or imports, to sort of bid in the base auction

but unwind these transactions.

Basically that's sort of in violation of the basic design element of RPM, that it has to be a physical market, not a financial market.

The other reform has to do with demand response. Let me start by saying that we believe that demand response should play a critical role in this market, but we also need to be pragmatic and practical about the requirements of demand response.

There is sort of a legacy product, which is the 10-by-6, which means the RTO can only deploy demand response ten times during the summer; and each time they deploy them, they can only deploy them for six hours.

So think about that. Demand response is actually replacing coal assets, and that's fine if that's the right market outcome.

But it is really critical and important to make sure that we also maintain reliability during the winter period where if you don't have a coal asset and demand response is replacing it, that demand response needs to

participate in the winter as well.

I would like to end my remarks by sort of emphasizing that PJM needs to continue to oppose out-of-market entry. This has happened in New Jersey and Maryland, but ultimately the Federal Court voided these contracts due to the commerce clause.

I do applaud PJM because even on sort of day one, they were very opposed to it; and I also applaud PJM for avoiding as much as possible the proliferation of RMR contracts, and we saw that example in the first energy retirement of the Hatfield and Mitchell plants.

I look forward to your questions either now or during the roundtable.

COMMISSIONER McCABE: Mr. Schukar?

MR. SCHUKAR: Good afternoon. I'm Shawn Schukar with Ameren Energy Resources, and I'd like to thank the Chairman, Commissioners, and Commissioner McCabe for the opportunity to speak on resource adequacy.

I thought we would start with just a little background on Ameren Energy Resources.

As you know, we're in kind of a transitional period. Some of our assets are being sold to Dynegy. The other assets are being moved to another entity in the marketplace.

But in today's world, we still own or operate about 5,000 megawatts of generation in Illinois, and that generation sits in PJM, MISO, and then some of it is actually outside of the organized market.

So our experience is with the two RTOs and then also moving power and capacity between those RTOs and from outside the market.

When you look on the map, you see several generators here. Two of the generators have actually been mothballed. One of the things that is important to us as we think about the capacity markets going forward is that we get the right signals for our generation.

We've experienced the pain that it causes to communities, that it causes to the people who work at these facilities when you have to mothball them and shut them down.

At the end of the day, it may be the right decision; but we want to make sure that decision has all of the right inputs and isn't distorted in marketplace.

On the other side, we also are active in the retailing and marketing of our power. So we are active in the wholesale marketplaces across the Midwest.

We sell to utilities, municipalities, and cooperatives across the market, but within the State we're active in the retail market. So we sell to the commercial, industrial, and residential loads within the state of Illinois.

So also important as we think about this construct is the signal that we give to the customers at the end of day because the actions they take and the contracts that they are willing to enter into are affected by how the market moves.

How volatile is the market? Is that price really high? Is it really low today? And what are their expectations? And what forward price signals can they see out there

to make decisions, especially if they want to make decisions around energy efficiency or demand response?

So the two questions, I'd say one was related to how do we achieve resource adequacy? I think the best way to achieve resource adequacy in a competitive market is to have the right pricing.

As Dean mentioned before, the price signals that we receive are energy, capacity, and ancillary services. Those all fit together because our assets can be different.

You can have a resource that is not very flexible. So it's not as valuable for ancillary services, and you don't get as much revenue from that as you might from the energy and capacity market.

So we need to make sure that when we're making investments in these resources, that we're getting the right price signal.

One of the opportunities that we think is there is to ensure that the price signal is over a long enough period of time to ensure that when we're making investments, that the

risk isn't so great that we have this high hurdle rate before we'll make the investment.

So currently, as the folks from the RTOs identified this morning, we've got a one-year and a three-year construct. Our view is that construct isn't long enough.

We don't think it's long enough for investment decisions. We also don't think it's long enough for some of our customers to make the kinds of decisions they need to make about "Can we make the right kind of investments for demand response or energy efficiency?" because they're trying to make a balance between "How do I invest in my operations, or do I invest in something else?"

When you look at the time frame and say "Why does that make sense?" the transmission system gets planned on a long period of time, 10-plus years.

As Mr. Rismiller identified this mornings, the generation in transmission fits together. Generation supports transmission, but transmission also supports the movement of

generation from place to place. So having those aligned on the same time frame is very important to us.

It's also important when you look at planned upgrades. For us to make a planned upgrade, it's not six months or a year from now.

We plan on making upgrades that last for 7 to 10 years, and making those investments and having certainty around that is very important to the decisions we make going forward and sending the right price signals to the marketplace.

Dean mentioned a little bit about some of the distortions in the energy market, and that's important to us because if you have signals that don't indicate what's happening in the market, you're not getting all the revenue or getting the right price signal for the investment.

Reem and Dean both mentioned the impact of the wind and the production tax credit, but another one that I'll identify from Midwest ISO is when we get into periods where we have

to call on reliability units, that actually drives the marketplace down during that period of time.

So at the same time when you're expecting high energy prices, you get lower energy prices in the marketplace, which sends a distorted signal and hurts when you're thinking about making investments into the marketplace.

So getting those energy signals right and getting the markets designed correctly is very important for us.

One of the other areas that we think is important is to make sure that -- can we go back to the previous slide? I'm sorry -- there is not artificial barriers.

We believe that we should operate the marketplace in a manner that recognizes the physical capabilities of the marketplace, and then we should try to align the marketplaces.

The marketplaces do not have to be the same, but we should make sure that by being able to move energy or capacity between the

markets, that we don't have a distortionary effect that you create gaming opportunities within the markets. So we believe that the baseline should be look at the physical capabilities of the marketplace.

So on the next slide, one of the things we have struggled with and what we're showing here is two units. They sit about 7 miles apart. They're here in Illinois. One is a unit that's within PJM; the other one is a unit that is in the Midwest ISO. They connect up to a common place on the system, about 2 miles away.

But when you look at the price signals they send from the capacity markets, they're significantly different.

One of the questions that was asked was: Are we getting the right signals for capacity? When I look at this, I would question are we really getting the right signal?

We may be, but it looks odd that you have units that are this close together, both physically and electrically, that you would get this much of a difference in the price

signal.

So the opportunity there -- and the Midwest ISO and PJM are working together to ensure that the markets do function better, that you get some of the timelines associated with putting in requests and how the capacity markets align, getting those all lined up so that those markets can function much better together.

We need to get it right because you could be making an investment in one plant, and it could be exactly the wrong investment to make. That's going to hurt the marketplace, and it's going to hurt the consumer at the end of the day.

Finally, there was a question about what are we seeing in the future?

I was around in 1997-'98 when the marketplace had a tight capacity, and it was a result of some regulatory issues in the nuclear space. Some storms came through, and prices skyrocketed in the marketplace.

So when I look at where we're at today, one of the issues that feels very similar to

me is we've got regulations sitting out there that could have an impact to us in the market.

Now, if those regulations come about in a way that we start seeing a lot of plants that today think they can continue to make the investment but they're unable to because the cost is too great, then you have this kind of step of capacity going away.

So what was the learning back in the '97-'98 time frame that I think we could take into account today?

One is that you had to have good coordination; and I think with the MISO and PJM, we have a lot better coordination than what we had back then. I think that's an advantage for us.

Another place is that you have to account for the variability of the assets that are out there. So if you don't have good long-term signals, you better have a very robust transmission distribution system to enable you to move the power from the places because we were trying to move power from

across the US, and it was limitations on the transmission systems.

So if you have uncertainty on the generation side, making sure that you have a robust transmission side is pretty important for us.

Finally, then, the last point I'd like to make is, you know, long-term resource adequacy requires long-term focus and coordination between all the stakeholders. It's the RTOs; it's the consumers; it's the companies like the ones sitting here at the table today.

Reliability is more than just in the RTO. It's across the system. So making sure that we are coordinating across the RTOs is important; also, making sure that we're not putting one resource at an advantage or disadvantage to others.

We've got demand response, energy efficiency, generation investment, transmission investment. We should align the timelines and the opportunities so that the correct investments are made to ensure that

the system is reliable and as low cost as possible.

Finally, as we've talked about, the market signals need to be there, and they need to be there in a time frame to align with those investment decisions.

With that, I thank you for the opportunity to put forth our views. If there are any questions, I'll be available.

COMMISSIONER McCABE: Jason?

MR. MINALGA: Good afternoon. Jason Minalga with Invenergy.

I appreciate and thank the Commission, Commissioner McCabe, and their staff for putting this together and for including us and allowing us to provide our perspective. We greatly appreciate the consideration.

Just a quick overview on Invenergy. I don't want to get into too much advertisement here, but we're a company that develops, owns, operates wind, solar, and natural gas facilities throughout North America and Europe.

Again, you can see some of the

statistics here. We're the largest wind developer in the country. We have a significant amount of gas resources as well.

Management has a significant amount of experience in the sector.

Again, we've developed 7 gigawatts of generation now over our portfolio.

We're headquartered here in Chicago and employ over 500 people globally.

In terms of Illinois, I thought it was important to emphasize this. Illinois is home to our headquarters. We're about two blocks from where we're at right now.

It's also home to our control center that operates most of our plants throughout North America. Unfortunately, due to the rules, we can't do the European ones out of there, but we do hire a significant amount of staff. They're on a 24/7, 365 basis.

In terms of breaking down the portfolio, you can see that. We've got a natural gas plant here in the State under construction, a wind generation portfolio here in the State as well as projects that we have built and sold

to utilities and load-serving entities, a solar plant that's currently the largest here in the State, and a battery that operates alongside one of our wind plants here in the State.

So with that, over a ten-year period we've invested over $2 million in the State, if you look at that portfolio, just to give you some magnitude.

What I wanted to do today -- I knew, just based on the folks that are here, we're all familiar with each other. We move in a lot of different circles.

I wanted to deviate a little bit and hit the spots that may be a little different in terms of perspective and not repeat a lot of what's been discussed today. There's a lot of points that I agree with, some that I disagree with.

What I wanted to go into is the fact that we are a little more unique. We're a project finance shop primarily at our company. We're not publicly traded. We're a privately held company. We deal a lot with financial

institutions.

And with that, there's a high degree of analytics, market fundamentals, and discipline that comes in terms of when we make investments.

So with that, again, it's a unique perspective here that may be different than others that are, you know, in our industry and space here.

What we want is functional markets that everyone can operate within. We've heard a lot of talk about equitability. We agree with that, allowing for a diversity of business plans to be able to participate.

Again, you know, the more competition you have, the better price signal, the better it is for the consumer.

Our industry is very capital and intensive, as we're aware. Again, with that folks aren't going to put money at risk unless there's a certainty that they're going to recover that money with a return for their exposure.

In terms of the MISO market as it

relates to Illinois, my company would have no plans to participate in that. There's no rational price signal that would allow us, again, to guarantee that return plus the original capital outlay to our financiers in order to allow us to participate in that.

In terms of PJM, it provides a one-year price signal three years forward in time. In comparison, MISO provides an annual product approximately two months forward in time, which precludes the ability to forecast what's coming, not to say that that's, you know, bad. That's just the design that's been chosen for that footprint.

It's not to say either that PJM is better or perfect or that they have found the solution. I think there's a lot of complexity to all of this that's been discussed today.

To that point, the historical clearing prices, if you look at them at PJM, they have been rather volatile. Again, going back to the viewpoint of the type of business plan that we have, we need that certainty.

If you have a volatile price point, again, it's not only bad for consumers, it's bad for rational investment.

So with that, you know, the capacity rules in PJM also continue to change and be modified. That adds another level of volatility where if you don't have any consistency, you can't draw patterns. You can't look at correlations. You can't compare things on an apples-to-apples basis over a long-term time horizon.

Again, what it does is it causes the financial folks that we interact with to potentially discount and haircut a lot of the revenues that we may forecast in a pro forma when we go to develop a resource.

The other thing with the PJM construct as well, you know, as much as we want to say it's a market, it's not. It's still very administratively managed in terms of how it's administered and how the price is arrived at and all the rules and things that are prescriptive that we have to go and work around.

Again, to successfully and efficiently project finance a new generator, we need certainty. We need predictable cash flows, preferably on a ten-year-plus basis. Even three years would be helpful, but a one-year price three years out is not helpful from our perspective.

Again, our business is primarily doing power purchase agreements with load-serving entities, utilities, municipals, co-ops, et cetera; and through that it facilitates the ability to finance new generation.

However, again, the way that the State is currently restructured in Illinois, those opportunities are rather nonexistent. I won't say they are completely nonexistent, but it is difficult to operate in that.

So the short-term outlook, again, as most folks have said, we're oversupplied.

The other key thing here that we've continued to watch and I know the markets are also having some difficulty around is the uncertainty of future demand forecasting based on some of the changes in the economy, some of

the changes in how the system is operating, consumers having more power now and abilities to interact with the utilities and the energy sector.

So the effects of demand response and energy efficiency are often, I think, underestimated, and that causes some inefficiencies in the market as well.

The other issue that we have -- again, I mentioned it with the MISO market with the rational price signal -- is the fact that -- a few folks mentioned earlier that they are primarily dominated by vertically integrated utilities.

Those folks have the ability to go back to the Commission in a ratepayer and recover their operating shortfalls through rate recovery.

Folks like us and the folks here at the table do not. We have to figure out how to recover all that through the markets.

The other issue I mentioned was the PJM price. Again, we characterize it as a whipsaw effect where you'll have a year where it's

rather high. It may entice some consideration of investment; but by the time you can get to it, the price has dropped.

Then it stays low for a few years, and then a few years later it will rebound back up, which it's kind of difficult to react to that. Some folks may be able to, but from our perspective it's difficult because, again, you need some sustainability. If it's moving around, proving that to a bank is rather difficult.

Again, that leads to a lot of the discounting that I mentioned earlier by the financiers.

The other one is the fact that low-capacity prices may be acceptable today in the short term, but it could discourage long-term investment and more efficient cost effective resources that could lead to a lower overall total cost to the consumer over the long term.

I'll breeze through this one pretty quickly. Basically what we're getting at here is, again, we need certainty over a more

sustained period of time than just a one-year instantaneous price signal.

What we'd like to see is more of a long-term capacity strip that will allow folks to make decisions around that, that gives you that certainty that you need to make good financial investments.

It also provides the ability and benefit to the consumer where they can hedge on a long-term basis because they do have that long-term price signal and can lock into that for a greater period of time.

The other issue, too, is there's two components to this. You've got the issue of existing resources and the issue of new market entry. The existing resource, the current markets may work for.

I'll put it in an analogy of a house. They have to cover a tax payment because they may have already covered a lot of the huge lump sum that they've put in over the years and recovered that through the markets and paid that down.

A new entrant has to figure out how to

cover the principal, the tax, the interest, and everything else that they put into the house. Again, with the one-year price signal, it's rather difficult to do that.

That's all I've got.

COMMISSIONER McCABE: Thank you.

A lot of the issues you've raised deal with barriers between the RTOs, which kind of gets to seams issues.

I was just interested in your thoughts on some of the existing forums to discuss that issue, such as the Joint and Common Market and IPSAC, which I can't remember what it stands for.

But are those venues helpful in helping with those kinds of transfers?

MR. SCHUKAR: Shawn Schukar.

I would say that we have seen -- as I indicated, through the Joint and Common Market discussions we have seen improvements between the Midwest ISO and PJM and how they work together in trying to get their timelines aligned, getting the issues on the table.

They have a work plan that they have

gone through and are trying to make adjustments to make it better, and so we have seen improvements there.

MS. FAHEY: We feel the same way. We feel that there's been a lot of work. They meet at least once a month to discuss interface pricing, transmission planning, outages, the markets, data exchange, et cetera. We believe that they have just been working really hard and making a lot of progress.

MR. MINALGA: I agree with these folks, although I will deviate, though, as there is some low-hanging fruit that I think could be worked on and improved.

It's around issues that are probably a little more straightforward to solve, such as transmission operations and, again, more of managing the flows across the seam as it relates especially to the Illinois-Indiana border.

CHAIRMAN SCOTT: Jason, let me ask you, if I can: With the gas prices being what they are and the markets having done what they

have done and with everybody's opinion that at least in the short term there's enough capacity here, make the argument for me about long-term contracts and how that makes sense.

Again, our purchase agreements that you're advocating for, how that makes sense under that backdrop.

MR. MINALGA: Sure.

Well, that's a complicated one. I can go on different tangents off of that one and say that the gas prices in the State will -- I think they've got nowhere to go but up, but we can argue that another day.

CHAIRMAN SCOTT: That's a fair point.

You read different analyses of that, but just about everything that you read says it's going to stay somewhere south of 7 bucks for the next 15 years, 10, 15 years.

MR. MINALGA: It's even tighter than that. Well, there's a handful of arguments that I would make.

The first one is, again, having a long-term contract, especially from this

context I'll talk more about our renewable portfolio. You don't have a commodity cost to manage around. So you can lock into that hedge.

In the event that someone is wrong in forecasting the gas price staying that low and it does spike, you're protected against that.

To the extent that, again, the gas price stays that way, again, there is also value in diversity, too. There's a little bit of a rush to gas right now, I would say. For me to tell you to put all of your 401(k) money in Google stock I think is mistaken. There is value in diversity.

So, again, it depends on what the State's objective is in how they want to meet the portfolio that they want to set forth in the long term. I'm not telling you you have to go to a long-term PPA, but that may be the efficient way to get you there.

As a free markets guy and an economist, I'm not telling you to re-regulate or anything like that. So there's a whole, you know, issue of complexity around that, too, of how

do you do that with continuing to keep the free markets that we have here in the State with restructuring?

I think you can get there through the RTOs if they were to create, again, a more long-term capacity price strip that could give you that long-term certainty payment that may be viewed in the same context as a PPA, just a different vehicle.

MS. FAHEY: I would just comment on that.

So at least in PJM, there's been very healthy and robust new entry in the market. Some of these plants have PPAs. I don't know if it's long-term PPAs, maybe two to three years, but I think they enter the market primarily because of the advantages of shale gas.

They have confidence in the PJM markets. They enter the markets because, again, the RPM is not perfect, but at least it's better than all the other capacity constructs out there.

So you are seeing very robust entry in the market. The last auction ended up in over

4,000 megawatts of new entry.

COMMISSIONER McCABE: Any other questions before we break briefly and set up the roundtable?

I want to thank all the panelists for some great presentations and highlighting how complex this issue is. We will continue that discussion. Maybe we can also respond to each other in some roundtable discussion. Five minutes to set up, so 3:00 o'clock. Good.

(Recess taken, 2:53 p.m. to 3:00 p.m.)

COMMISSIONER McCABE: It's roundtable time. First I'm going to open it up to questions from my colleagues.

I thought it would be fascinating, given that we have several panels, if some of the panelists want to address statements made by other panelists or ask them questions or clarify any statements, have at it.

We'll just start with Elise. Having heard all the discussions, any concluding thoughts?

MS. CAPLAN: That's a little bit of a surprise.

Actually, I was very interested in Invenergy, Mr. Minalga, some of your proposals. There's a little bit of overlap with some of our interest long-term contracts. So I think you're more interested in maintaining some of the existing structure.

I was wondering if you could elaborate a little more. I'm not sort of drawing it all together. I did have a question.

COMMISSIONER McCABE: If the one who speaks would say their name again for the court reporter and Commissioner Colgan, and those of you in the center tables will have to get close to the mic. Thank you.

MS. CAPLAN: Caplan, C-a-p-l-a-n, American Public Power Association.

MR. MINALGA: Jason Minalga.

Again, what I'm proposing, as I put on there -- and I didn't want to go into all the detail around it. It's on the slide.

I think if you craft it in a way similar to how the FTR markets are starting to evolve,

right, you've got an annual strip. You've got the seasonal strips.

We kind of have that in PJM. You've got the annual strip. You've got the IAs that take care of more of the shorter term as you're firming it up, as you're coming closer to that time horizon.

What I'm advocating for is that you would go on the flip side of that further into the future where you'd have a longer strip going further out on a longer time horizon. Then you could lock into longer term prices, even if it's for three years.

Obviously, for us 10 to 20 years would be great, but I get that the world changes and you don't want to lock in too long. Three would still be great.

I'm not advocating, again, to blow the system up here or anything that others may have advocated for on the other side.

I would also say -- you know, I heard the comment earlier that there's a difficulty to do bilaterals. I disagree with that. The markets allow for that to happen today.

PJM and MISO can correct me if I'm wrong and any other RTO; but as far as I'm concerned, my company does a lot of bilateral transactions, and we're not precluded because of these structures.

COMMISSIONER McCABE: Anyone?

MS. FAHEY: If I can comment just to provide a bit of an opposing point of view to Jason, our company was opposed to the RTOS stepping in and having a much longer commitment because that's not the job of the RTO; right?

So if people want to do a bilateral transaction that lasts for ten years or longer, there's absolutely nothing that prevents them in the market.

But more importantly, what PJM does is because they have a forward price three years forward, you know, if loads do not like that price, then they are incented to hedge against it.

But we would be very opposed to sort of the RTO stepping in and starting to do, you know, multiyear contracts on behalf of load.

I don't think that's a good idea.

DR. BOWRING: Joe Bowring.

So to comment on all of that, it certainly is the case, as has been pointed out, that the RPM construct does not disincent bilaterals. It's quite the reverse. It provides a transparent market signal around which people can trade bilaterals in lots of ways.

They can trade bilaterals, including bilaterals with financial counter-parties. We've seen a number of new units financed with fairly long-term forward financial counter-party bilateral arrangements which provide, for example, for hedging on energy revenues.

So there are lots of market-based bilateral mechanisms which are not only not prevented by RPM but are facilitated by RPM.

Related to what Reem just said, I agree that it does not make sense for PJM and the markets to try to enter into long-term contracts on behalf of load. That's precisely the purpose of bilaterals.

The one year forward -- I'm sorry -- three years forward for one year obviously is not enough to finance anything; but the point is if you have stable markets and a stable market design, then people can and there's confidence that the market is going to reflect the fundamentals and people will build based on that.

We have, in fact, seen people build based on that one year, three years forward. That absolutely is adequate to finance merchant generation. We've seen that, and you don't need long-term contracts. Again, that's been demonstrated.

Clearly, some people would like long-term contracts. We've had lots of examples of people asking for that, but it's not necessary.

MR. MINALGA: Can I respond to that? Jason Minalga.

I think you have to take a look at it on a case-by-case basis on the new entry that is happening. A lot of it's in the constrained LDAs where the prices have been blown out

pretty good and stay consistently high compared to the rest of RTO.

Secondly, I think a lot of it is by incumbents or folks that are essentially expanding an existing plant or already have the capacity locked down where, again, there is not a lot of risk of coming in on a green field.

So I think I take a little bit of exception to it.

MR. BRESLER: This is Stu Bresler, PJM.

I figured there have been a few comments about what an RTO should or should not be. Really, my participants should be expressing those opinions, but I don't want to sound opposed to that.

I just wanted to sort of close the loop on sort of PJM's efforts to really gather and explore stakeholder and market participant opinion with respect to longer term strips in the capacity market because we originally had what we called a New Entry Price Adjustment or a NEPA in the RPM construct where a new entry

resource could qualify for multi-years of payment at the same clearing price they originally cleared. It's very difficult to qualify, a fairly complicated process.

So we opened the stakeholder discussion a year ago probably to reexamine the new entry price adjustment, that longer-term certainty.

We also opened it to the possibility of longer-term auctions and had stakeholder discussions around longer-term auctions. A lot of issues surfaced.

Should it be mandatory? Should it be voluntary? Large credit requirements for new entry if you're locking it in for years worth of capacity payments?

I don't want to leave the impression that we stopped the discussions because it was hard. That certainly is not the case. We've had a lot of very difficult discussion we've gotten through in our stakeholder process.

To Reem's point earlier and to Joe's point, we have seen a significant amount of new entry occurring with the existing construct.

So the question became: Do we need to really go that far down this road with the concern being that we're not getting new entry without it when in fact we are?

Now, it's true what Jason says that a lot of that new entry is in the eastern part of the PJM system because that's where the price signals have been showing where we need the new entry, where the price signals have been the highest and the most stable.

That is really, I think, the proper functioning of the market constructs who have the price signals reveal that need. So I think that's sort of the proper outcome of the market.

MS. CAPLAN: I just want to sort of maybe add a little clarification on this, where the bilateral contracting discussion is.

I think it's clear you can do contracts for differences. You can do side contracts. You don't have to pay the PJM price, if that's available.

A lot of our concerns maybe have to do more with autonomy and what we've seen happen

over the past couple of years with a Minimum Offer Price Rule; that when there was sort of an increase, especially in feet, implanted by the contracting, then there was sort of -- through FERC there were rule changes made that would now make it more difficult for a public power to clear the new plants.

So it's really contracts when you're arranging a contract for a new plant. There have been similar FERC decisions in other RTOs.

So our concern is really about getting a new plant built and establishing the contract and getting that through the market and the recent rule changes. So it's kind of specifics about it.

COMMISSIONER McCABE: Other responses to prior discussions? Otherwise, we may have a few other questions.

CHAIRMAN SCOTT: So what we've seen here is -- I'm just following up on Stu's point.

What we've seen here, as we saw on the slides, some of the merchant things that are

built that are already contracted for or are municipal based or they're the kind of one-off -- it's probably a wrong term -- the kind of one-off projects that we've seen that have been legislatively driven because they're protecting jobs, protecting, you know, Illinois coal, those kinds of projects.

I don't want to misinterpret your last response. You're saying that the market here, the kinds of projects that we have seen being built here are the kinds of projects you would expect to see given the price signals on the western half of PJM?

MR. BRESLER: This is Stu Bresler, PJM, again.

What I was saying is that where we're seeing the new entry is where we would hope that the market signals would drive new entry, which is in the area where it's necessary because that's where the price signal is showing the need. The prices are the highest and most stable.

As far as who is developing the project, is that what it's regarding?

CHAIRMAN SCOTT: That's the other part of it because a lot of this discussion is about if the right price signals are there or the right market is there, if the stable market is there, the people will come in.

I guess, who are some of the people that would do that?

MR. BRESLER: It's really not the incumbent utilities that we see as developing the new generation. It's more the merchant players.

I don't personally have visibility into those that have long-term contracts or not associated with the projects that are being developed.

What I do know is it's not, like I said, the incumbent investors in utilities that are choosing to make the investments in new projects.

It's the alternative players, LS Power, CPBs, these types of merchant projects where we're seeing new investment.

DR. BOWRING: Can I say something in addition? Joe Bowring.

First of all, just to be clear, part of the reason that we are seeing the investment is due to prices, but it's not capacity price impact, although that's part of it.

When you build a brand-new combined cycle, most of the revenue is coming from the energy market. So it's an L and P play, an energy play, very much more than it is a capacity market play.

Capacity market is gravy, but it is absolutely not the essential driver. It's L and P, and that's what you would expect. Those L and P differences reflect both the expectations of market participants as well as reflecting the real locational differences in the cost of energy.

The second thing is that if people are building bilateral contracts, holding aside the public power entities, that's not a bad thing. That's not inconsistent with RPM. That's not evidence that RPM is not working. If anything, it brings evidence that RPM is working.

Finally, one last thing, you mentioned

what Bob Ethier said. I think what faculty meant -- and I've said something similar -- is that in markets like PJM where you don't have load-serving entities with long-term obligations on the buy side, they have absolutely no incentive to enter into long-term contracts; right?

So in PJM, while there's some retail competition, it's not at the point of Texas where there is simply open entry and every customer is up for bidding and it is open to the market.

It you had that, then you'd potentially have LSEs with a longer-term horizon and the ability and incentive to enter into the long-term contracts.

Thanks.

COMMISSIONER McCABE: I wanted to get thoughts from all of you, both RTO and stakeholders to the RTOs, on the role of OMS and OPSI, the State PUCs, and whether we should be doing more, whether it's seams, boundary issues, or other areas.

MR. BRESLER: This is Stu Bresler at

PJM again.

Again, I think following from my answer to Commissioner Maye's question this morning, we see our relationship with the state commissions as an invaluable resource for us with respect to engagement in our stakeholder process, development of our market rules, understanding the uniqueness of each state's situation with respect to their own retail access programs and particular state regulations.

So certainly from the standpoint, I think, of OMS and OPSI and from PJM's perspective, obviously, OPSI, we look forward to that continuing engagement as our markets continue to evolve.

I think Jason's point is a good one about stability of market rules. Certainly, we need to achieve that to the greatest extent possible; but on the other hand, we have to recognize when the market's continued evolution is necessary to make sure that they are as efficient as they can possibly be.

So I think from PJM's standpoint,

whether it's a seams issue or whether it's our own PJM market rules -- and the market rules affect the seams issues -- really, I think we look forward that continuing and frequent and ongoing in-depth engagement with our state commissions as we continue forward.

MR. DOYING: Richard Doying with MISO.

Certainly, I feel the same sentiment. The states are very active in all of our stakeholder processes. As I noted, we've been working with the OMS on resource adequacy specifically.

We also have been working with OMS and OPSI on some of the seams issues through the Joint and Common Market process.

So I know that we have a very good relationship with the states, and they are a very important stakeholder in all aspects of what we do from planning to market operations.

MR. WRIGHT: This is Kevin Wright.

I would agree with Commissioner McCabe that the regional state committee approach in OMS and the ISO footprint and OPSI and PJM

footprint is a very appropriate vehicle to advance these issues and to work in a cooperative manner with other states in getting the RTOs to a point that meets each state's -- I've been advocating for Illinois, but for everyone's interest to be met.

Particularly, I give my experiences on the OMS side and MISO, the board there -- particularly the board there. The management has been very receptive to OMS input and comment.

My observation is that the FERC has also taken interest in comments coming from the OMS and OPSI. Just to illustrate the point, the FERC really gave OMS the last word whether the MISO market was ready for its start-up back in 2005.

To me that's extreme -- I shouldn't say "extreme." That's extraordinary deference to regional state committees. We all have our issues, but I still would advocate that we work within those frameworks. I'd also suggest that's not the only one, but it should be a primary one.

MS. FAHEY: I guess from a market participant perspective, I think it's going to be really helpful for the states to be involved in some very key market design changes.

I'll give you an example of what PJM is about to file at FERC, and it's not popular because they are going to attempt to limit the demand response product that I talked about that only participates in the summer.

It's really important for the state commissions to listen to the reliability needs for the RTOs.

So PJM, I'll start by saying they have been extremely pro demand response in the beginning. A lot of demand response participants get paid exactly the same as a generating resource or what have you, but they are attempting to do unpopular things for the sake of reliability.

I think it's really critical that all the Commissions, whether OMS or OPSI, understand why they are trying to do things that, again, may not be popular by either

limiting demand response or limiting imports, et cetera.

So if it's for reliability, I think it's really important for you to be involved.

COMMISSIONER COLGAN: Commissioner McCabe, I have a question.

If I had a take-away from today in general from the discussion that we've had here, because the topic of our discussion is resource adequacy and do we have it in Illinois, I think what I have heard is that in general there is resource adequacy and that it's there for the foreseeable future.

I guess my question, then, is: If that is not the right take-away for me to have today, what would be the nuance that we could add into that that might modify a sense of confidence that we do have resource adequacy?

What are the issues that might create a process for Illinois in the foreseeable future with resource adequacy?

Some summary comments.

MR. MINALGA: Jason Minalga of

Invenergy.

I thought about that question here over the last week. We operate in a lot of different markets and can see the trade-offs between them and how certain things function and trying to peel back why certain things happen.

We've made investments in Texas, which is probably the furthest extreme of restructuring. We don't seem to have as hard of an issue of financing projects there as we do in PJM, so to try to figure out why.

What do they do that's different than what we do?

A couple of things that we noticed -- and I'm not saying that it's fully attributed to this or that this is reality. The things that I took away is the generation portfolio.

Texas is heavily based on gas. They've got some base load, a little bit of nuclear and a little bit of coal, but it's mostly gas. So they have the price volatility. So you can afford to get away there even without a capacity payment and build a new

resource.

So I would attribute a little bit of it to the volatility in the energy prices. Especially here in Illinois and the RTO, prices have been relatively stable.

There's not a lot of volatility going on right now, you know, in the dynamic that we're dealing with right now with the economy coming back and load growth slowly coming back but not continuing to increase as it had in the past.

Then you've got some new resources coming in and low gas prices. I would attribute a little bit to some of that.

DR. BOWRING: Joe Bowring.

Just very briefly to reiterate a couple of points that have been made in response to your question, I think that while there is reliability, we need to make sure to make some adjustments to the market that have been proposed in order to ensure that reliability continues to be robust.

The first one is to enforce the appropriate physical requirement. That's been

talked about today. One is on demand side and the other is on imports.

The second is to make sure that the market design does not result in price suppression, both from the 2 1/2 percent adjustment in demand as well as the definition of the limited demand side.

Both of those things are critical in order to make sure the price signals are appropriate going forward and that we continue to get the right result for Illinois and the rest of PJM.

MR. KOLATA: This is Dave Kolata from the Citizens Utility Board.

I think that there's no question. I think we all agree that from a resource adequacy point of view right now, we're okay. So we're really talking here about the future.

We obviously don't know exactly where things are going to go, but there's pretty clear trends out there that we're going to see more renewables, certainly more wind.

Also, if you look at the declining cost curve of solar, if that continues, as I think

it has, in just a few years that's going to be cost competitive in Illinois without subsidy. I happen to think that's a good thing, but I also think that that's reality.

Because of that, we need to prioritize more flexible resources in the generation market.

While I'm not completely opposed to some of what you're talking about on changing the rules around demand response, I am concerned that in effect you're privileging base load assets with base load perspective at the expense of more flexible, more time-sensitive response.

So I just want to make sure that at the end of the day, the demand side can participate fully and equally.

Also, at some point Stu would love to talk to you about how distributed generation might be able to -- you were sort of going down the path, "Well, if they're behind the meter, they could participate as a demand response resource in a way."

But if you think that through, perhaps

they should be an energy efficiency resource in a real sort of way as behind the meter. If so, can we work on things like that to, again, try to incorporate the demand side into our market?

MR. BRESLER: This is Stu Bresler at PJM.

Just sort of an initial reaction to that, when I said "energy efficiency" in the context of distributed degeneration earlier, what I really meant was sort of an overall demand reduction.

I don't think I indicated the term "energy efficiency" from the standpoint of a capacity market, but certainly they can be a load management resource beyond demand response; right?

When you typically think of demand response, certainly they can be a way for loads to manage their consumption at the times when it would be most beneficial for them to do it.

Even if they are not in front of a meter or participating directly in the wholesale

market, certainly they can utilize in that sense as well, absolutely.

DR. BOWRING: Can I just add something?

I think that, actually, RPM much more so than for scarcity pricing -- Stu, I'm sorry -- facilitates the adjustment of markets through renewables.

The thing that renewables do is largely intermittent, largely reduce the energy price. That's virtually free energy, you know, from a short-end marginal cost perspective. So it tends to supress the energy price, which tends to reduce net revenues to thermal units.

Obviously, we need to keep keep thermal units around. The capacity price adjusts automatically. As the net revenues to thermal units go down, the capacity price goes up.

So the capacity market is a good way to manage the introduction of additional renewables, and it has an automatic offsetting mechanism.

It's certainly not the case that RPM is somehow biased in favor of base load. It's

simply biased in favor of having a single definition of "capacity," which anybody can meet, including DR.

There's no reason from a market perspective DR can't provide the annual product. Of course, it can in the same way a CT can provide the annual product in combined cycle.

MR. WRIGHT: This is Kevin Wright from the Competitive Energy Association.

To kind of follow up on Commissioner Colgan's question, it's been said multiple times, in terms of the short run, there does not appear to be a problem, but it's the long-term that we have to keep watching.

Particularly, the Commission needs that assistance in the long-term view, which I think stakeholders here can help provide.

What I see wearing both a legislative process hat and a regulatory process hat is that the environmental regulations and the unknown extent to which those may affect generation supply is not going away. It will be used as an argument why Illinois should

continue to look carefully at resource adequacy and generation supply.

As Chairman has indicated, there's been several legislative initiatives where the background for those initiatives is that the generation sky is falling.

Due to these EPA regulations, coal-fired plants are being put out of business. Generation will be constrained.

It goes that there's a need for more base load. We hear that on the legislative process side repeatedly, whether it's a number of former projects that would satisfy that base load generation concern. I think the Commission needs to stay ahead of that.

To get to the point, I think today's policy meeting has been exceptional in bringing this topic to the fore, but I wouldn't leave it at today's policy meeting.

I would encourage the Commission to do this on an annual basis at a minimum to keep ahead and to be proactive as opposed to reactive in doing its own due diligence.

COMMISSIONER COLGAN: Let me ask the

question.

Do you think that from your perspective in your current position and former Chair position, do you think that the Commerce Commission in its current structure has the authority to do the kind of work that we need to do to ensure resource adequacy to the future, or does this need to be tweaked somehow?

MR. WRIGHT: I'm not sure about authority.

What I'm trying to express is that the Commission be provided with timely information to guide it in terms of its future decisions regarding resource adequacy.

I guess what I'm trying to suggest here is that this is the first step today. It doesn't necessarily have to end here today, that the Commission remain proactive on this issue and can do so through this kind of forum.

I mean, you certainly have the staff resources that you've engaged at MISO and PJM. I would continue to take advantage of that.

Both you and Commissioner Ann McCabe are engaged in the two regional State committee approaches. I would encourage the Commission to stay actively involved in that venue.

But I would also suggest that perhaps just like you do on the annual gas supply for the winter and the annual electric supply for the summer, that maybe you keep this as an agenda item to revisit on a yearly basis and to engage these stakeholders that are here before you today and others that maybe should be included to keep you informed and ahead of the curve for those long-term outlooks on resource adequacy and capacity market and pricing.

MR. KOLATA: David Kolata from the Citizens Utility Board.

Whether you have all the authority you need I don't know, but I do know you have some very powerful tools in the implementation of Smart Grid that has not been explored, assuming that that works. It does implicitly get at a lot of these issues.

I also think that the Illinois Power

Agency process -- leave it at that -- offers some of those same tools.

So I do think that certainly you should continue dialogs like these, but it's important to be involved in the regional process and all of that, absolutely true. It's also important to use the tools that we have here in Illinois and maximize the value of that.

MR. MOORE: John Moore, Sustainable FERC Project.

In the short term, it seems like resource adequacy is pretty good in Illinois. I think that in the longer term, OMS and OPSI should be thinking about a concept -- I hate to use the technical term -- the net energy demand, net of all the renewable energy resources and distributed resources that are on the grid.

MISO is already doing this because it has 10,000 or 12,000 megawatts of wind power on its system now, and we are going see more of that in PJM and interregionally with more resources in SPP.

Thinking about just peaking mid-merit and base load plants in the traditional sense I don't think is going to be true five or ten years from now even in the same way.

I like David Kolata's point about more flexible resources. They are already working heavily on this in California and on the East Coast. I think we'll be seeing more of this in Minnesota in particular, which is shooting for up to 40 percent renewable energy standards. They are doing studies on that.

I would highly recommend everyone to read the PJM Draft Wind Integration Study, really exciting stuff, but they are doing a final stakeholder review of that on December 5th.

That shows the impacts, which we think are on the main positive, of 100,000 megawatts of energy, not capacity but energy in the system to meet like a 30 percent-type standard.

So the times they are a changing.

MR. DOYING: Richard Doying from MISO.

Maybe to follow up on that and try to get back to Richard Colgan's question, we are seeing a portfolio of evolution. When we think about resource adequacy going into the next four years, I think we need to recognize the speed of that in terms of the retirements, in terms of the new gas additions we're going to see with the Marcellus shale in Pennsylvania.

You're going to continue to see a lot of west to east flows of wind power. There's nowhere for it to go further west. So it is headed to the east where the demand is.

The best wind-producing fuels are out in Iowa, Minnesota, the Dakotas. We'll continue to see wind development out there. So we're going to see flows in that direction.

I would expect the low-cost gas to head in the other direction, head to the western areas. We need new generation resources there.

I think when you think about portfolio evolution, you need to think about the flexibility of the market rules to facilitate

those types of transactions. I think it's not healthy from a resource adequacy perspective to think about it on an RTO-by-RTO basis.

We don't think about selling energy on that basis. We really let it move according to market participant desires for transactions across the seams. I think trapping capacity gives you the same type of problem.

In response, I'd just comment on one remark that was made earlier that it's good for those capacity transactions to occur but only if the rules are aligned. That's simply incorrect.

If you wanted to buy a car here, you're very close to Wisconsin. You don't have to have the same emissions requirements, registration requirements, license requirements in Michigan or Wisconsin that you do in Illinois in order to buy that car and move it in here. You comply with the local requirements when you get the car here.

It's the same for any energy or capacity transaction. You comply with the rules where

the energy is delivered when it's delivered. It's actually very simple to do, very simple to facilitate.

I think we're making good progress there in the Joint and Common Market process. I think that's going to be one of the critical initiatives for the overall region.

COMMISSIONER McCABE: (Inaudible) If we wanted to locate things larger than just RTO-by-RTO basis, does that mean that the projected potential shortfall in 2016 can be dealt with by working with other regions (Inaudible)?

MR. DOYING: Absolutely.

We have thousands of megawatts of imports today. We get them from Manitoba. We have imports from just about every border on our footprint today. I would expect that those will likely increase.

Demand response penetration is certainly another thing that I would expect to see. Again, as new low-cost gas generation is built, where the gas price is low, I would expect that to move as well. At least that's

the direction it should go based on the economics.

MR. ELLIS: Dean Ellis with Dynegy.

Again, addressing the original question about perhaps is there an immediate-term or a long-term problem, I'll just summarize by saying that definitely take a look at the best practices across the different regions.

Many of the regions are facing the same exact questions, the same exact problems. They are addressing them differently. Obviously, these problems are manifesting themselves differently across the regions and into different markets.

It's particularly interesting here in Illinois. In other locations we talk about single-stake ISOs; and was pointed out earlier, this is a multi-ISO state, which is very unique.

Perhaps there are some efficiencies to be gained there looking across the two different markets and, again, how the different markets address these issues.

Thank you.

MR. BRESLER: Stu Bresler from PJM.

I just wanted to -- since Richard had mentioned the capacity transfer concept, certainly we have seen that occur over the years where we're continuing to work with MISO on making sure that we remain coordinated as far as that issue is concerned.

One does need to remember that when capacity does commit itself into another region by virtue of the capacity construct that exists in that region, it is committed to that region.

When that region needs the energy because that region comes on an emergency situation for energy, that is where the energy is committed to go.

I think we all need to keep that in mind as we progress into the future with respect to how these capacity constructs interact.

MR. DOYING: Sure.

That's the way our market works today, that as you clear as a resource, then you are committed to MISO for the period of that commitment, the same way that RPM works today.

So I think you're right. That would certainly need to be a required element that would need to continue.

COMMISSIONER McCABE: Other thoughts on today's discussion?

MS. CAPLAN: Mine is pretty quick. I have sort of a more big picture thought from having sort of watched the RTM markets and everything.

Obviously, I'm not going to have any additional expertise on resource adequacy needs. I know, as everybody else knows, there's a lot of complications on the horizon.

We have this uncertainty of shale gas and gas prices and where that will go. We know there's a lot more gas. There's all these sort of resource issues, uncertainties.

My question is just to think about whether -- I'm probably going to offend people in the room -- this RTO decision-making process is really reflective of kind of the public good perspective.

And so if you look at, for example, this

demand response discussion, you have the demand response providers and their financial interests, the generators' stuff wanting to keep things tight.

You have a lot of competing interests emerging that may not really be the best for consumers or best for the environment. It's a result of these kinds of competing interests playing out through the RTO. I think we should give thought as to whether that is the best way to deal with some of these.

My advice for the Commission or for OMS is to stay active at FERC and keep that kind of public interest in mind through all these proceedings.

MR. MOORE: John Moore, Sustainable FERC Project.

I certainly agree with the sentiment behind what Elise just said in general about that, and it's always good for the state organizations and other stakeholders to ask about the continuing value of RTOs because they are very strange creatures indeed with very strange governance and issues and

accountability issues sometimes.

I know they are also trying to do their best to manage reliability and keep the lights on. More power to them to do that.

My comment is, Commissioner McCabe, going back to your question about what can OMS and OPSI do.

Because they really are the only game in town when it comes to anything approaching a regional forum for the states themselves to participate in with goals involving reliability and long-term resource adequacy for the grid in the two RTOs, I certainly think that, going back to the information sharing point -- well, picking up on Stu Bresler's point about the RTOs being the source of information, I think getting more information on the demand side and the use of the demand side resources, NDG and grid planning is very important in the markets because that is often not as visible as generation supply.

So I think regular annual types of reviews where Illinois in particular is on the

demand side would be very valuable and in other states as well. They really can't support each other.

To the point of generation resources have to be physically deliverable into another RTO and can't overpromise what's not available, well, then reducing demand helps with that. So there's that.

I think also with the 111(d), the carbon rule compliance standards, that's another excellent opportunity for states to work together cooperatively with the RTOs to help figure that out.

MR. MINALGA: I just wanted to address the comment that came up a couple times on my panel. I didn't want to digress out of there, so I figured I'd save it for here.

Most of my comments were for the thermal side of our business. Again, being that I have a renewable portfolio, I felt the need here to set the record straight on some things that were stated.

It relates to the negative pricing and

the subsidies. All resources receive subsidies, whether indirect or direct, whether you call them subsidies, incentives, tax efficiencies, whatever we want to call them. So to set that part of it straight.

Then the other side of it is, you know, negative prices don't occur as often as I've been reading. Fortunately, I guess I have access to data and can go and scrub it and do what I want with it.

It's more 2 to 4 percent of the time on the high side here, and a lot of that is somewhat self-inflicted. You know, in areas that you have a big clustering of units that don't want to be flexible, that don't want to cycle, that don't want to ramp and they must run into a market and become a price taker, that causes an issue.

Another point of it, too, is it's probably sending a signal that you need some transmission because you have bottled generation and nowhere for it to go.

So I just wanted to get that out there. Thank you.

COMMISSIONER McCABE: Shawn?

MR. SCHUKAR: Shawn Schukar, Ameren.

Just to circle back with a couple of the issues, in 2007 gas prices were going up. Load was going forever. Look at where we're at today.

Market prices are low; gas is going to be low forever; and we're not going to have any load growth. So to the point that Dave made, things are going to change, and we don't know how they are going to change going forward.

So it's keeping your thumb on what's really happening with resource adequacy, and it's not just the resources. It's the system and the capability of the system. Those things are tied together.

I think that's a great place for the Commission to keep the focus is in those two areas.

COMMISSIONER McCABE: Thank you.

MR. WRIGHT: If I wasn't clear to Commissioner Colgan's -- sorry. Kevin Wright, Illinois Competitive Energy Association.

I do not think the Commission needs integrated resource planning authority. I think you have the assets and resources here to gather the information that you need in order to make whatever regulatory or decisions going forward after today.

If I wasn't clear on that, Commissioner Colgan, I apologize.

COMMISSIONER COLGAN: Well, thank you for that.

COMMISSIONER McCABE: Commissioner Colgan? Okay.

COMMISSIONER COLGAN: I was following up on a comment. Thank you for that and to tell you that that was almost a direct answer to my question.

MR. WRIGHT: Well, I've been gun shy here the last few days on other matters, but I thought you deserved a direct answer.

No, you don't need to go back to integrated resource planning. You have the assets and the information and the resources to do what you need to do without specific authority to go back to that old way of

planning.

COMMISSIONER McCABE: Dr. Bowring?

DR. BOWRING: My comment really picks ups on that in a way.

There has been some conversation about the need for flexible resources, and there was a partial response about the need for flexible markets. I think that's a key distinction. It's almost the paradigm distinction I was talking about between the regulatory view and market view.

I would say that we need as flexible a market design that can permit resources to respond to market signals. You will get the appropriate kind of flexible resources then if you have the appropriate design.

The last thing in the world we need to be doing is picking and choosing what kind of resources to build going forward. We've all seen that, really, that only leads to mistakes.

Thanks.

COMMISSIONER McCABE: Any other comments?

Again, I want to thank all the panelists and the people in the audience for coming today. These are complex issues. None of us are economists, and mastering some of these subjects is a long-term process.

So we welcome continued discussion. John has already given us reading assignments, but whether you want to come in and meet with us, send us materials, tell us about meetings you think we should really attend, we welcome that.

I want to thank Cameron Schilling for helping put this together, Ariel Tesher, and Randy and his group. They help us ascend the learning curve on a weekly basis.

Thank you. Thank you very much.

(Which were all of the proceedings had in the above-entitled matter, concluding at 3:45 p.m.)

STATE OF ILLINOIS)
) SS.
COUNTY OF DU PAGE)

I, Jean S. Busse, Certified Shorthand Reporter No. 84-1860, Registered Professional Reporter, a Notary Public in and for the County of DuPage, State of Illinois, do hereby certify that I reported in shorthand the proceedings had in the above-entitled matter and that the foregoing is a transcript of my shorthand notes so taken as aforesaid to the best of my ability.

IN TESTIMONY WHEREOF I have hereunto set my hand and affixed my notarial seal this 14th day of November 2013.

Jean S. Busse

Notary Public

My Commission Expires
July 25, 2017.