BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

DEMAND RESPONSE IN ORGANIZED : Docket Number

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Hearing Room 2c

Federal Energy Regulatory Commission

888 First Street, N.E.

Washington, D. C. 20426

Wednesday, May 21, 2008

The above-entitled matter came on for technical conference, pursuant to notice, at 10:14 a.m.

PRESIDING: David Kathan

COMMISSIONERS PRESENT:

Commissioner Wellinghoff

Commissioner Spitzer

P R O C E E D I N G S

(9:05 a.m.)

MR. KATHAN: The Demand Response Technical Conference will begin. Good morning.

My name is David Kathan. I'm a Group Manager within the Division of Policy Analysis and Rulemaking, in the Office of Energy Market Regulation here at the Commission.

I would like to welcome you all to today's Technical Conference, Demand Response in Organized Electric Markets.

The purpose of today's Technical Conference, is to consider issues related to demand response in organized electric markets.

Staff was directed to hold this Technical Conference on wholesale competition. The purpose of this conference is to provide a forum for RTOs, demand response providers, and other stakeholders to express their views.

The focus of the conference will be on issues that are outside of what has already been addressed inside of the NOPR, looking at future reforms and looking at areas that have not already been addressed and that have been covered in the NOPR.

It will also serve as guidance to the RTOs and ISOs in the areas that they should include as they consider demand response further.

With me at the table, are several Commission Staff members. On my right is Dean White from the Energy Innovation Center; Michael McLaughlin from the Office of Electric Reliability; Carol White from the Office of Enforcement; Ed Murrell from the Division of Policy Analysis and Rulemaking; and Kevin Kelly, Director of the Policy Analysis and Rulemaking Division.

On my left, is Elizabeth Arnold from the Office of General Counsel, Ryan Irwin from the Division of Policy Analysis and Rulemaking; and Ken Thomas, also from the Division of Policy Analysis and Rulemaking.

Our first presenter today, will be -- I'm sorry, I take that back. Before we get started, are there any opening remarks from any of the Commissioners?

COMMISSIONER WELLINGHOFF: Thank you, David. I just want to thank the Staff for organizing this conference.

It's a subject that's extremely important to me, demand response and how we can better integrate demand response into these markets.

By the way, I'm Jon Wellinghoff, Commissioner for the Federal Energy Regulatory Commission.

There are two topics that we're really focusing on here today: One, how we can, in fact, expand the compensation and economic benefits that demand response provides into the market, and how those benefits can be recognized and compensated, I think, is extremely important, to ensure that we can optimize the amount of demand response.

Secondly, how we can reduce the barriers, non-economic barriers and other barriers that may, in fact, prevent demand response from being incorporated into these markets.

So I'm very anxious to get started, and look forward to the panels. I'm very happy that we've got the Staff running this conference. Actually, I think the Staff does a much better job running conferences, than the Commission does.

Sitting up there, I think Staff asks better questions. I also want to welcome President Smith, and appreciate, Marsha, your coming and leading off our conference.

MR. KATHAN: Commissioner Spitzer?

COMMISSIONER SPITZER: Thank you. I am in agreement with Commissioner Wellinghoff, that the Staff will ask better questions, I'm confident, than we, although I want to underscore the importance of this topic.

This is an industry that faces great challenges, economic challenges, challenges in global commodity prices, challenges in construction costs for new generation and new transmission.

The integration of demand response into those organized and bilateral markets, is one of the best ways that government, working in cooperation with the private sector, can improve the circumstances of American ratepayers.

I appreciate the materials that have been submitted. I thank the Staff for moving forward with this. I thank my friends from NARUC and the state commissions, for their attendance, as well as those in academia and in the utility sector, and very much look forward to the proceedings.

I'm going to be going in and out, because I have to take care of some materials, including those I have to submit to the Congress today, but on behalf of Chairman Kelliher and Commissioner Kelly and Commissioner Moeller, all us will be very attentive to these proceedings. We thank you and look forward to an interesting day.

MR. KATHAN: Thank you, Commissioner.

The structure of the Technical Conference: We'll begin with a presentation from NARUC President, Marsha Smith, followed by three panels.

The first panel will look at value and appropriate compensation for demand response. After lunch, we'll look at barriers to comparable treatment, and solutions to eliminate potential barriers.

Our first presenter, as I mentioned, is President Marsha Smith. Marsha?

COMMISSIONER SMITH: Thank you very much. My name is Marsha Smith. When they put that in my remarks, it's sure to remind me who I am. Most of you already know me.

I'm a Commissioner on the Idaho Public Utilities Commission. This year, I have the privilege of being the President of the National Association of Regulatory Utility Commissioners, which we all affectionately refer to as NARUC.

On behalf of NARUC, I want to thank you for this opportunity to address the Technical Conference and appreciate the attendance of Commissioners Wellinghoff and Spitzer.

As you know, NARUC represents state public service commissioners who regulate the retail rates and services of utilities, including electricity and natural gas.

Like the FERC, our members are obligated to ensure fair, just and reasonable rates for those utility services.

I would like to commend the FERC and Staff for holding this important and timely Technical Conference.

Congress, as we know, is considering sweeping changes to our energy policy, and consumers are beginning to see, and, I think, will see in to the future, higher utility bills, due to increasing demand and due to increasing costs of all kinds on the providing of that service.

Demand response, as FERC recognized in its 2008 Summer Market and Reliability Assessment, has increased in importance, both as a means to reduce load requirements and as a means to provide ancillary services for operating flexibility.

Demand response has always been an important tool in the state regulatory toolbox. For years, NARUC and its members have supported demand-side management as a means of making the most efficient use of electricity and a means of reducing overall costs of providing service.

NARUC's members and FERC serve the same constituents. Those are the utility consumers. And although we have different responsibilities and authorities to do so, we all must keep that in mind moving forward.

After all, wholesale and retail market structures are means to an end, and that is providing services to the end use customers.

My comments today, focus on two topics: NARUC's demand response initiatives and FERC's implementation of the demand response proposals.

When I became NARUC President last November, I challenged our members on three key issues: Innovation, efficiency, and leadership.

All three relate to demand-side management. America is blessed to have ample natural resources, but, as these resources diminish, we must be good stewards and demonstrate real leadership to balance our energy demands with environmental responsibility.

NARUC, through its policies and active membership, has, indeed, been a leader. I have the privilege of Co-Chairing the National Action Plan for Energy Efficiency, along with Jim Rogers, the CEO of Duke Energy. NARUC was an original sponsor of the Action Plan, when it was first initiated in 2006.

The Action Plan is a collaboration of federal and state government officials, working alongside key industry leaders, focused on making energy efficiency a priority, and recognized as a key resource.

Within the Action Plan, energy efficiency is examined from a broad, grass roots perspective, and recognizes the importance of energy savings at peak times, through papers, outreach efforts, and pledges from states and utilities and other industries all over the country.

The Action Plan has offered state-specific policies to overcome barriers to greater investment in energy efficiency.

Part of the Action Plan's Year Three effort, is an issue paper on coordinating demand response and energy efficiency policies and programs. Also, as most people here are well aware, NARUC has two ongoing collaborative efforts with our FERC colleagues, that deal with demand-side issues.

The first is the Demand Response Collaborative, and it is exploring how state and federal policymakers can better coordinate our respective demand response policies and practices.

We recently released an RFP from a research project, to do a report on overcoming the barriers to demand response through coordinated retail and wholesale regulatory policies. Responses to that RFP were due May 16th.

The other partnership just announced in February, is our Smart Grid Collaborative. This collaborative is still in the formative stages, but there is a high level of interest, both within NARUC and the general public, as well.

This collaborative touches on grid modernization and ways of possibly giving consumers the ability to make real-time decisions about their energy usage.

My written testimony goes into greater detail on these joint programs. If I neglected to do so earlier, I would ask that my written testimony be made part of the record.

As with all joint efforts we're pursuing with FERC, we want to express our appreciation of FERC's willingness to examine these issues jointly, because we think there's great synergy in addressing both retail and wholesale at the same time.

Against that backdrop, I would like to turn to the more specific issue of why are we here today? To improve demand response in organized markets.

Properly implemented demand response initiatives, can help hold down wholesale power prices, can increase awareness of energy usage, increase market efficiencies, enhance reliability, and encourage new technology.

But FERC's implementation of any proposals, should not result in prescriptive, generic, or one-size-fits-all rules.

As I'm sure you all are aware, this is an area of particular sensitivity, as demand response traditionally falls under state jurisdiction.

FERC has recognized and respected the significant differences that exist between states and regions, and we at NARUC, appreciate that recognition.

Similarly, we believe that any new demand response initiatives should follow the same path and be implemented in such a way that differences in market design and existing state and/or regional demand response programs, can be recognized and accommodated.

States have traditionally done an excellent job of overseeing distribution systems; planning, siting approval, reliability assurance and consumer protection.

This responsibility also includes jurisdiction over demand response policies.

The advent of organized markets did not change FERC's jurisdiction in this area. We appreciate FERC's acknowledgement in its 2007 Demand Response Report, that the actions of several states to introduce greater demand response into retail markets, partially addresses the need for wholesale/retail coordination.

Today's discussion of ideas and strategies to overcome barriers to demand response, continues our existing activities. From NARUC's perspective, this continuation of current activities, is a good start.

The Demand Response Collaborative is a good step in coordinating state and federal efforts, and future FERC policy, if any, in this area, should be implemented with the same spirit of cooperative federalism embodied by this Demand Response Collaborative.

Displacing state authority in policy decisions, is a bad idea and could result in wasteful and unnecessary litigation that would delay implementation of important demand response measures, but the coordination of federal and state initiatives, offers both the most promising approach to managing the federal/state jurisdictional intersection in organized electric markets, and the best way to assure that the full benefits of demand response, are delivered to consumers.

I want to thank you for the opportunity to appear here today, and to take some time. I appreciate the hospitality of FERC. Thank you very much.

MR. KATHAN: Thank you, Marsha. We appreciate the time that you've taken to come here and present in front of us.

Based on where we are, why don't we go ahead and start with our next panel.

Our first panel will be examining the value and appropriate compensation for demand response in organized electric markets. We'll explore various issues concerning compensation and ensuring demand response resources are compensated in a manner that is comparable with other resources.

We will also examine whether demand response resources are appropriately valued for the benefits that they bring.

Our first panelist is Eric Woychik. Eric is Vice President of Comverge, Incorporated. Eric?

MR. WOYCHIK: Good morning, and than you very much. I want to thank the Commission for this opportunity to comment.

Comverge fully supports the Commission's focus on how appropriately-valued demand response resources can increase the benefits available in organized competitive markets. DR offers tremendous opportunities to resolve serious market problems.

The statement "appropriately valued," suggests comparable treatment of value, particularly with respect to DR, vis a vis generation and transmission.

The short answer is, however, that DR fails to be appropriately valued. The result is insufficient DR in organized markets.

The details in market rules, which, frankly, take us into the weeds, make all the difference for DR. That's where I think many of the issues lie.

Comverge offers eight points regarding RTO/ISO actions that diminish DR value and limit DR participation in markets:

First, ISO New England does not allow DR to participate in operating reserve markets. I know that's something they want to work on, and we look forward to working on it, but it's certainly a deficiency right now.

ISO New England imposes annual requirements for DR to be available in the forward capacity market, and it is relatively expensive for DR to comply by using generators.

ISO New England uses amortizing of prices, which fails to reflect the incidence of loss of load and imposes a disadvantage to DR which seeks to respond to seasonal thermal load.

While PJM allows for some current DR benefits to accrue, it has adopted market rules that diminish DR benefits, as follows: Changes to zonal synchronous reserve boundaries, without sufficient public review, which confers market advantage to generators; use of Tier I synchronous reserves before Tier II and the 25-percent limit on DR participation in this market, which confers major advantage to generators;

Removal of the transmission benefits from PJM's economic program, though transmission benefits are not a subsidy, according to PJM's market monitor; excessive metering and communication requirements that are unwarranted for DR; lack of ramp rate limits on RPM and ILR markets, to the disadvantage of DR that provides dispatchable ramping capacity; a newly adopted customer baseline approach; CBO that exempts problematic DR behavior, and fails to capture full DR value.

Again, this is a major issue. It relates to the gaming matters that have been of great concern to some here, and we want to work on that, as well, very closely with

FERC.

The proposed supplemental reserve product seems appropriate, but is, again, limited to 25-percent participation by DR, and generation is taken first before DR.

Four, SCM and RPM prices that are insufficient to enable investment in DR; five, California has a delayed use of DR's operating reserves. It's California ISO operating tariffs, and it has also delayed the use of DR as participating load, and we realize, again, these are tariff issues.

We look forward to working with the Commission and Cal ISO on this.

The primary overarching problem, is RTO/ISO governance and committee voting which result in market rules that cut against comparable and fair treatment of DR resources, to the advantage of supply-side resources.

In-committee voting needs to reflect the minority view of DR interests. This was raised prominently in the NOPR. We, again, hope that that can be addressed.

Number Seven: Adopted RTO/ISO market rules, in general, diminish the impact of DR on market prices and reduce the role of DR in market power mitigation, both of which are essential for workably-competitive electric markets.

Number Eight: In summary, as a result of the governance and decisionmaking of RTOs/ISOs, specific market rules severely undercut the value and use of DR in organized markets. I look forward to the positive disposition of many of these issues, and to working with the Commission and others on these things. Thank you very much for the time to offer these comments, and I look forward to the open discussion. Thank you.

MR. KATHAN: Thank you, Eric. Our next panelist is Daniel Violette, Principal of Summit Blue. Daniel?

MR. VIOLETTE: Thank you. I appreciate this opportunity. I have picked three issues to address in my introductory comments:

The first issue concerns calculating customer baselines used for customer settlement. Almost all demand response programs, either price-based or load-management-based, require an estimated customer baseline to calculate the delivered megawatts.

Accurate estimates of these load reductions using these customer baselines, determine the payments that are made to participating customers.

This is important to the value of the program, because these payments are funded by all electricity customers in the market. What we're seeing across the country has been considerable experimentation regarding the appropriate baseline estimation, but much of this information has not been consolidated.

It should be possible to develop methods that more accurately estimate customer baselines, and thereby more accurately estimate the load impacts of demand response programs. Development of customer baselines has been a point of debate in California and at the PJM, which has proposed some changes in their baselines.

There have been discussions at the New York ISO and ISO New England has also proposed a new method, so this is an issue receiving current consideration and one where I think we need to consolidate the learning across the country.

The second issue I have, is estimating the value of demand response as a resource in markets. In many cases, the load impacts that we see coming from a demand response program, are simply the sum of the load impacts that are estimated through these settlement procedures, but these settlement procedures are subject to a number of constraints and considerations.

The settlement procedures need to be readily understood by customers. They can't understand the business proposition that they're facing. They should allow for the customers to be paid promptly and they really are part of designing and marketing the program.

To meet the above criteria, a customer baseline should be as accurate as possible, but they cannot be too complex. Many of these customer baselines are subsets of the previous ten non-event days or use other methods such as the average monthly peak demand.

However, if we want to accurately estimate the DR program's resource contribution over an entire season, this may require more sophisticated approaches. These approaches would include all the data available in the season, and also use data across customers, in a single estimation method, so you would kind of validate the settlement number at the end of the season, and then reconcile how close settlements are coming to actual load impacts.

We can use more sophisticated methods that really aren't practical to be used for customer settlements to be used to determine how much customers are paid.

My last issue concerns the marketwide benefits of demand response. This is kind of a fundamental issue.

An increased ability for the demand side of the market to respond to price and resource scarcity, is important. If we don't have that type of demand-side elasticity now, if we get more, it should help all the markets.

It will help ensure efficient resource allocation markets; it will incent technology innovation, which I think is going to be critical to the future of demand response, and it will improve productivity in one of the nation's most capital-intensive investments.

DR programs and the technologies that support these programs, are still developing, and the value of DR will increase in the future. I see a number of trends that I think will lead to this increase.

The first is the increased automation of customers' load response. We're developing technologies through energy management control systems in commercial buildings and commercial sites.

We're developing increased automation in mass market applications. This will allow us the customer's load to be automated, such that they don't have to take any action.

If it's easy for them to participate in the program, it's more likely they will stay in the program.

That supports a second trend, which is an increased focus on firm reductions. I think that as demand response moves forward, we need to be able to rely upon it, count upon it, and I think the new programs are going to focus on providing capacity and firm reductions.

The third trend I want to draw out in these comments, is that I expect these programs to be targeted to benefit T&D and ameliorate system congestion.

So, for this future to materialize, demand response will require the sustained support of regulators and market operators. I'd just like to mention that the PJM DR road map is certainly a move in this direction. Thank you.

MR. KATHAN: Thank you. Our next panelist is James Eber, Director of Demand Response at Commonwealth Edison. James?

MR. EBER: Good morning. Thank you for this opportunity to present my comments today. I'm actually here on behalf of Exelon, which has three subsidiaries active in demand response programs.

ComEd, where I am currently working, can reduce its peak load by 1100 megawatts through its customer response programs. Forty-one hundred commercial and industrial customers participate through those programs.

They are very diverse, ranging from very large steel mills, to small community stores. Over 60,000 residential customers participate in our air conditioning control program, and 5,000 residential customers have elected to purchase energy at real-time prices.

ComEd has more than tripled its demand response available since the mid-'90s. Currently, Peco can reduce its load by almost 350 megawatts, with 130 C&I customers participating and 80,000 customers taking service on an off-peak rate.

For residential customers in the last five years, Peco has tripled the amount of load reduction available through its customers.

These numbers do not actually -- it's important to note that these numbers do not include the substantial load reduction by achieved competitive curtailment service providers active in both the Com Ed and Peco zones as well. Both Peco and Commonwealth Edison fully support and facilitate this growth of competitive service providers.

In addition, Exelon Generation is actively developing demand response products for the wholesale market, as well as demand response programs to offer to customers through its competitive retail supply business.

My involvement in demand response for over ten years, has taught me that the term, "demand response," doesn't really tell the whole story. "Demand" really means customers, and customers don't view themselves as demand.

They don't really view themselves as responding; they view themselves as participating in markets.

In my experience, there are three crucial factors needed to encourage customers to participate in these electricity markets: First, customers must be able to see and react to the wholesale prices for their products, either directly or through curtailment service providers.

Prices must be competitively determine, to reflect the actual value that results from the function of an efficient competitive market, and customers must have confidence that the wholesale pricing structure is stable and not vulnerable to constant regulatory change.

I'll expand on each of these. First, customers need to be able to see and react to wholesale prices. Retail customer curtailment service providers offer the critical link between the retail customers and the wholesale market.

Retail curtailment service providers participate in the wholesale markets and thereby enable retail customers to react to wholesale price signals, even when the retail customer does not directly experience the wholesale price signal through purchasing.

Demand response programs have flourished within competitive retail market services in Illinois and Pennsylvania, that dovetail well into the competitive wholesale market structure of PJM.

By their very nature, retail and wholesale competitive market structures, foster demand response participation, because they offer greater opportunities for demand resources to compete with other resources.

Second, prices need to be determined by an efficient competitive market, so that customers will see the actual value of the resource and react accordingly.

Customers will participate in demand response programs when they realize revenues from offering the demand resource, whether capacity, energy, or ancillary services, that are greater than the costs to offer those resources, but to make that assessment, customers must see the value of the resource to the market, not skewed by either subsidies or mitigation, rather, the price for resources, whether generation or demand, should be the product of an efficient, competitive market under whatever conditions exist at any given time.

So that customers see the right price at the right time and are able to offer the right level demand response, for instance, we undervalue energy at the time of system peak. Customers will not see the appropriate opportunity.

The result will be participation at less than optimal levels, however, if we allow inefficient competitive markets to set the price of energy resources, optimal participation of each resource, will result in an efficient market, to the benefit of all customers, not just those providing the demand response.

Third, customers and providers of retail demand response products, need certainty that the competitive pricing structures will be stable. Customers must have confidence that appropriate price signals will be sustained by stable competitive pricing structures, before they will make an investment in demand response.

Customers and their providers understand that the value of these resources will go up and down in the market, but if they have confidence that the market will be allowed to work, they will rely on their own forecast and invest appropriately for optimal participation.

Another example that proves this point, is that customer participation in PJM capacity markets, has tripled, following the implementation of the PJM reliability model in 07. RPM price signals are eliciting a large increase in interruptible load for reliability and forward price stability under the three-year forward option and this has give customers the price certainty they need to justify investment in demand resources.

In closing, I strongly believe that the Commission will foster optimal demand response by policies that allow price signals to reflect the value of energy during shortages, and that allow RPM to work to elicit optimal levels of customer response in capacity markets.

We think the Commission should allow competition to work in these markets, and any necessary improvements to PJM's energy capacity markets, should be made through the stakeholder process.

Again, thank you for allowing me to participate in this conference. I look forward to any questions.

MR. KATHAN: Thank you. Our next presenter is Lawrence Stalica, Vice President of Linde Energy Services.

MR. STALICA: I'd like to thank the Commission for allowing me to speak at this important panel. I have written remarks and offer them to be submitted into the testimony. I'll just work off of those remarks.

It's good to be here and it's good to be here as a manufacturing load that's looking to participate in demand response markets. It sounds like we are a curtailment service provider, but we're not; we're a load in 40 states across the country, and participate in a wide variety of demand response markets.

Linde Gas is one of the largest industrial gases companies in the world. We make oxygen, nitrogen, argon, and other gases for use in industrial processes and for commercial needs.

We formed in 2003, our own load-serving entity, with the sole purpose of controlling our energy costs in deregulated organized markets. By the end of this year, we'll be licensed in five RTOs in over ten states within PJM, ISO New England and the Midwest ISO, and soon to be ERCOT and New York ISO.

We have done this, not because we didn't have anything better to do, but because we saw our costs increasing and we wanted a way to control that. This was the best way, this direct wholesale approach is the best way to do that.

Electricity comprises in a typical air separation plant about two-thirds of our production costs. It is by far, the largest single cost we have when we make our product.

A little bit of background of our history: Before organized markets, we were participating in a wide variety of interruptible and real-time pricing programs.

We were on programs that supply utilities with direct ability to interrupt our load, thereby providing system reliability and help them forego the construction of new generation.

We currently participate in organized markets in a wide variety of programs in PJM's demand response markets, both day-ahead and real-time, PJM's synchronized reserve markets.

We're in the PJM's interruptible resource market, which used to be active load management, and New York ISO's as well as ERCOT's, acting as a resource market.

We do these on a case-by-case basis for our facilities, and we do not get free money from these markets. These are markets and products that require significant efforts on our part, controls and instrumentation. When we shut down and respond to price, we lose production, we have labor issues, as well as equipment wear and tear.

It comes down to a simple economic analysis. When we shut down, we usually have to make up that production during other periods of time, usually on off-peak hours or at night or on weekends when the system is under less stress and prices are more reasonable.

With all that said, and with that background, there are three points I'd like to make, with some subpoints below them. The three points are:

Demand response is absolutely essential to a well-functioning wholesale energy market.

The second point is, demand response needs to be appropriately compensated.

The third main point, is, demand response requires market rules that require development and growth. Demand response is essential to a functioning market.

It's not a market, if generation or supply is just supplying services into the RTO. Demand elasticity is needed. Right now, there's not enough.

In order to increase demand response, we need to make sure that demand response is appropriately compensated. I offer the position that a megawatt of demand response, is more valuable than a megawatt of generation.

When a megawatt of demand response comes on or reduces load during periods of high price, the price for everyone in the system comes down. That can't be said when a generator goes online. As the stack increases, the price goes up for everyone.

That needs to be recognized. We need to recognize costs associated, like I mentioned, like loss of production, labor, equipment, wear and tear, and technology.

In order to do that, there needs to be a variety of demand response programs. We need to focus on energy, we need to focus on capacity and ancillary services.

We need the ability for demand to participate in all those markets.

Finally, we need market rules. It's my opinion that RTOs are the key component in forming and developing these demand response markets. They should take the lead, they should assign executive management to these programs, to make sure that they are driven and successful.

We need to remove the barriers between load and those wholesale markets, because any barriers just simply reduce the economic benefit to the end use customer, and that's going to reduce his ability to participate in those markets.

I look forward to the open discussion. Thank you again for the opportunity to make my remarks.

MR. KATHAN: Thank you. Our next panelist is David Brewster, President of EnerNOC, Incorporated. David?

MR. BREWSTER: Thank you very much. I appreciate the opportunity to be here today to discuss the value of demand response resources, as well as the appropriate level of compensation for these resources in the organized wholesale energy markets.

By way of background, EnerNOC is a demand response energy management solutions provider. We currently manage over 1500 megawatts of demand response capacity across nearly 3,000 commercial, industrial, and institutional customer facilities throughout North America.

The current debate about the appropriate level of pricing for demand response in wholesale energy markets, has, unfortunately, deteriorated into an unhelpful rhetoric about subsidies for demand response resources, rather than focusing on achieving the most efficient wholesale market design.

We appreciate the fact that the Commission today has decided to allow this issue to be further explored.

I'm going to focus my comments on two points today: My first point is that demand response market opportunities, should absolutely exist in wholesale energy markets today.

Well designed demand response market rules, make wholesale energy markets more efficient, and, to the extent that they do so, opportunities for demand response to participate in these markets, should be preserved and further enhanced.

My second point is that incentive payments above and beyond LMP, provided to demand response participants, are completely appropriate and justified, as long as they make the overall market more efficient and address some of the existing market barriers faced by demand response resources.

EnerNOC is extremely supportive of expanding retail market opportunities to give customers the opportunity to see and to respond to real-time pricing signals. This will ensure the only way that we can ensure that customers are properly incented to either reduce load or use load according to the real market costs of energy.

However, we're not there yet. All the wholesale markets in the United States, encompass areas where real-time pricing opportunities are very limited to nonexistent. It may be a very long time before substantial numbers of consumers adopt and adjust their consumption behaviors to participate in real-time pricing opportunities.

Other than that, it's going to take time for technologies and business models to further evolve, so we help customers remove the complexity of these markets and optimize their participation.

As a result, there exists today, a significant disconnect between the retail and wholesale markets. The wholesale markets are not as efficient as they should be.

Wholesale markets need a mechanism by which retail customers can see and respond to wholesale market prices. Demand response participation is just that; demand response participation in wholesale markets today, corrects this very significant market failure.

Wholesale markets should not be permitted to accept known market inefficiencies, while we wait and hope for real-time-differentiated pricing opportunities to develop.

The FERC and RTOs and ISOs have a continuing and ongoing responsibility to ensure just and reasonable rates for customers. For this reason, wholesale markets need to preserve opportunities for demand response resources to participate in energy markets, and to remove market rules that create artificial limits on demand response's participation.

My second point is how to appropriately compensate demand response resources in wholesale markets. As an absolute minimum, wholesale markets should have a permanent market rule that allows customers to be paid the difference between the LMP and the customer's retail rate.

This is not a subsidy and it's not an incentive, and, as such, this should be considered as sort of the default starting point for determining the appropriate compensation for demand response resources in wholesale markets.

The issue then becomes more narrowly defined, as to whether providing an additional incentive or subsidy payment beyond the difference between LMP and the regional rate, is appropriate.

From our perspective, it is important to point out that in mature and properly designed energy markets, without barriers, in which demand and supply can interact dynamically, incentives or subsidies, would be neither necessary nor appropriate.

EnerNOC does not support incentives for the sake of propping up the demand response energy. EnerNOC's position is that incentive payments above and beyond LMP, are absolutely appropriate today, in order to foster the development of demand response resources, as long as these incentives payments make the wholesale energy markets more efficient.

As has been shown repeatedly in numerous programs in RTOs and ISOs across the United States, properly designed incentive payments have benefitted the wholesale market, by making demand more elastic, by reducing opportunities for market power abuse, and by bringing down wholesale power costs for all consumers.

Along the glide path toward optimally efficient wholesale markets, incentive payments to demand response participants, can and do play a valuable role for making today's markets more efficient, with incentives, than without them.

In addition, cost-effective incentive payments for demand response resources, make additional sense, to mitigate some of the substantial market barriers that have resulted in the demand side of the market being underdeveloped, virtually everywhere.

There are examples throughout the United States, in which demand response resources cannot participate in a comparable manner as generation and other resources in the market. Market rule limitations on demand response participation bear directly upon the pricing discussion here, because, to the extent that demand response is foreclosed or limited in its participation in any of the various RTO/ISO markets, demand response may need an appropriate market incentive to attract meaningful participation.

My point in raising these barriers in this discussion about pricing, is that we cannot look at the question of incentives or subsidies, in isolation. To the extent that demand response does not have full opportunities to participate in wholesale markets and where the demand side of the market is otherwise underdeveloped, it is absolutely appropriate to consider incentives as a remedy to partially overcome existing barriers and help make markets function more efficiently.

The purpose of the incentives is to counteract market failures associated with the broken link between wholesale and retail markets and insufficient demand response resources in the market.

In summary, we believe that participation in demand response resources in wholesale energy markets, is absolutely essential to address an existing market failure, and that the question of incentive pricing for demand response, is appropriate in the context of utilizing these incentives to overcome barriers to demand response, as long as such incentives make the market, as a whole, more efficient.

Ideally, we will move beyond incentives and foster a mature wholesale market in which there is dynamic interaction between demand and supply, but much work lies ahead, before we get there. Until that time, let's not pass the buck; let's ensure that demand response has the opportunity to make a difference by fully participating in wholesale energy markets. Thank you very much.

MR. KATHAN: Thank you, David. Our next panelist is Robert Borlick, Energy Consultant with Borlick Associates. Robert?

MR. BORLICK: Good morning. I appreciate this opportunity to present my views to this Commission regarding the value of demand response and also how it should be appropriately compensated.

I'm currently assisting the Midwest ISO in the development of their demand response programs, but I want to make clear that these are my views and not necessarily shared by the Midwest ISO.

I submitted a prepared statement, which basically makes four points. Let me summarize what they are:

The first point is that the main benefit from demand response, is that it avoids investment in peaking capacity and also, to some extent, transmission and distribution assets.

Point Number Two: Demand response helps control market power. There is a lot of theory that indicates this, as well as empirical evidence that's emerged from some experiments that have been run.

Point Number Three: Demand response makes generators less dependent on capacity payments, and it can potentially eliminate the need for capacity markets altogether.

The last point -- and this is a little change of topic -- regarding how we compensate demand response, demand response providers should not be double-compensated. By that, I mean, paying them the market price and also allowing them to keep the savings that they gain from not having to pay for that curtailed energy through their retail tariff.

I guess, on this subject, David Brewster and I disagree.

Let me flesh out those points a little bit, since I have three minutes left. Demand response is the near-ideal peaker. The reason is, it has a very low capital cost.

However, it does have a high operating cost when it runs, and, when it's called, it's expensive, and the operating cost that I'm referring to, is the foregone value of the demand response provider, in giving up the productivity and the comfort and convenience that that curtailed energy could have provided to him.

This is important. It's typical ignored in cost/benefit analyses of demand response programs, but this is a big cost, and shouldn't be ignored.

The second topic: As demand response becomes increasingly effective in controlling market power, it will allow this Commission to relax other regulatory constraints, like price caps on energy offers and other forms of energy price caps.

This allows demand response to set prices during scarcity conditions and to let those prices rise to what is needed to clear the market, which segues into the third point: These higher scarcity prices, will allow generators to earn more in the energy market and make them less dependent on capacity markets, and, if it's allowed to go to its ultimate end, will end up with an energy-only market, and we can away with the capacity markets.

But this won't necessarily happen by itself. It won't happen, for example, if we claw back all the scarcity rents on a retroactive basis. We have to let those generators keep those scarcity rents, and allow them to know, on a next-day basis, that they are going to get to keep them.

In this regard, the ISO New England capacity market doesn't do that, and PJM does.

Finally, the issue of double compensation: David Brewster makes the point that we should consider subsidies and allow them, if it makes the market more efficient.

Nobody can disagree with that. In fact, it's kind of a tautology. The fact remains, though, that the subsidy payments make the markets less efficient, not more efficient.

They do that, because what they cause the demand responder to do, is to curtail too much load, which, in turn, causes generators to be backed off. That could provide the curtailed load at a lower cost than the value of that load to the demand responder.

You say, well, why would the demand responder do such a thing? The only reason he does it, is because he gets the subsidy payment.

Without that subsidy payment, you know, he wouldn't over-curtail, which means that it's not only inefficient, it's also inequitable, because other consumers have to pick up that subsidy payment.

With that, I conclude my summary, two seconds late.

MR. KATHAN: Don't worry about it.

(Laughter.)

MR. KATHAN: Our next panelist is David LaPlante, Vice President of ISO New England.

MR. LaPLANTE: Good morning. Thank you for the opportunity to express ISO New England's views on valuing and compensating demand resources.

Increasing the role of demand resources in the electricity marketplace, has been a longstanding federal and state policy goal. In New England, we're making significant progress towards achieving that goal.

As a result of the first forward capacity auction, we will have about nine percent f our 2010 resource base in demand response. This could grow to up to 13 percent in 2011, depending on the outcome of the second forward capacity auction later this year.

With this many demand resources in New England, determining their proper value and compensation, is essential to realizing its benefits of achieving market efficiency and reliable system operations.

In determining the value and compensation of demand resources, it's helpful to start with basic market principles. An inefficient market clears at a price where the marginal cost of production is equal to the marginal benefit of consumption.

For the electricity market to be efficient, all resources must be priced at their marginal value. That's the price of producing the next megawatt for demand resources. The marginal value is the benefit of consuming the next megawatt hour.

As we develop market rules for compensating demand resources, it is essential to apply these market principles. If not, we risk inefficient production and consumption decisions.

For example, if demand response is under-compensated, there will be too much supply and prices will be too high. However, is demand response is over-compensated, efficient production will go unused, prices will be too low, and investment in new resources may not occur.

Therefore, in determining compensation for demand resources, the benefits of not consuming energy, must be properly considered. Importantly, the value and compensation for demand resources, depends upon the specific product the resource is providing.

In New England, demand resources can participate in all three wholesale energy markets -- capacity, energy, and ancillary services.

I'd like to briefly discuss each of these, in turn. Our capacity market rules compensate demand resources, based on their load reduction during hours when seasonal peak loads are highest.

These demand reduction values are then increased to reflect both transmission and distribution losses, and the planning reserve margin. This results in the capacity value of the resource.

Demand resources are then paid the capacity clearing price in the forward capacity auction. In this case, compensation for demand resources is clearly comparable to supply resources.

There are two options for demand to participate in New England's energy market: Large resources, greater than five megawatts, can participate fully in the energy market, submit a dispatch price and be curtailed, based on the energy price.

There are also a number of price-responsive demand programs that compensate load reductions during times of high prices at the locational marginal price.

These programs expire on June 1st, 2010, when payments begin in the forward capacity market. As the region discusses the extension or termination of these programs, it will be important to stick to the principle of compensating resources at their marginal cost or marginal value that I mentioned earlier.

There are similar options for resources to participate in our operating reserve and ancillary service markets. Larger resources can participate fully in the market.

While we have developed a pilot program to enable smaller demand resources to participate in the reserves market, to date, we have not had full subscription to the pilot program, so we're still looking for additional participation in that.

The initial results of the pilot program show that small resources, including demand, can provide operating reserves, however, we are extending the program to learn more about how much reserves each resource can reliably provide.

One of the things that we have learned, is that the megawatt rating for the resource, for providing operating reserves during all hours, is generally lower than the megawatt rating for providing capacity during non-peak hours.

In this case, to ensure comparability with supply resources, demand response in these markets, must be compensated, based on their actual performance during reserve events. To date, most demand resources have been dispatched, based on a specific reliability trigger, for example, running short of operating reserves.

The resources that ISO New England has purchased in the forward capacity market, have this type of trigger. This approach is proving useful to encourage demand to participate in the markets.

However, as the amount of demand resource grows, more sophisticated approaches will need to achieve full comparability and integration of demand into all wholesale markets.

We will be addressing this problem as we prepare for dispatching the system with demand resources in June 2010.

The ideal solution would be to have all demand resources submit a price at which they would stop consuming.

This would achieve full comparability, fully integrate demand in the energy market, and properly compensate demand resources.

If this occurs, then demand would be responding to price signals and prices would reflect the intersection of marginal costs and marginal benefits.

Obstacles to realizing this efficient pricing for demand resources, remain and are significant, including flat-rate retail tariffs and a lack of integral meters. The challenge we face in the short term, will be to develop mechanisms that appropriately value and compensate demand, as the region works to remove obstacles to demand's full participation in the market. Thank you.

MR. KATHAN: Thank you, David. Our final panelist is Paul Peterson. He is a Senior Associate with Synapse Energy Economics. Paul?

MR. PETERSON: Thank you, David. I'm happy to be here to participate in this Technical Conference. Synapse Energy Economics is a small consulting firm located in Cambridge, Massachusetts.

We are currently very actively involved in both the New England ISO wholesale market process and the PJM wholesale market process, on behalf of a number of consumer advocate and environmental clients.

We also do work in a number of other areas. I'm going to refer to some of that other work in my comments.

I have provided to you in advance, a four-slide presentation. The first one is the title slide that identifies me and my company; the second is a very commonly drawn graph that shows Quantity 1, Quantity 2, Price 1, Price 2, and how, on a sloping supply curve, if you reduce quantity by a small amount on a steep part of the curve, you get a large reduction in price. That's the basic graph that everyone uses to talk about demand response.

I should also just comment that in my work, we spend a lot of time dealing with demand resources, which is a term I use to include both energy efficiency and small-scale distributed generation.

We think of the demand, the customer side of the meter, as the demand resource side of the meter, and the supply resource side of the meter, is the other side.

Although this Technical Conference is on demand response, a lot of my comments would also pertain to energy efficiency and small-scale distributed generation.

In fact, sometimes it's hard to distinguish whether what's happening in the marketplace, is the result of a demand response by a distributed generator coming on, or an energy efficiency application that's taking place.

When you have a reduction in quantity on a steeply-sloping supply curve, you get a large reduction in price. In the wholesale electricity markets, the results of that action reduce energy and peak loads.

They lower the clearing price, they reduce the carbon footprint for the region, they require less future transmission and distribution investment.

In short, we are proposing that demand resources should be viewed as the marginal resource. I'm in agreement with much of what the other panelists have said, although I will raise just a couple of issues for you to think about.

Dave LaPlante, whom I've worked with for many years, appropriately raises the issues of what are the benefits of not consuming? I would suggest to you that the benefits of not consuming energy, are enormous.

This is one of the issues that you, as FERC Staff, needs to grapple with in your world of dealing with wholesale market pricing mechanisms.

In the larger world, the issues of demand response, demand resource participating in markets, raises problems with historical utility revenues based on volumetric sales. That's very much a retail issue, but it's an issue you need to be aware of, if we're going to encourage greater adoption of demand resources and energy efficiency resources.

Your traditional utility is going to have a difficult time meeting its revenue requirements. This could be addressed through decoupling mechanisms or other approaches, but this is not a small or trivial problem.

In addition, if we're going to encourage more demand response, more demand resources in the marketplace, the history of the electric industry is going to change. The history has always been one of increasing load growth.

There are many indications now that that history is going through a transformation. Individual states have established very optimistic and ambitious goals of reducing energy consumption. Common phrases are: 15 x 15, 15-percent reduction in 15 years; 20 by 20, 20-percent reduction in 20 years.

If you look at the implications of those state policies, we will be using less energy, we'll have a lower peak load 20 years from now than we have today.

That is unprecedented in the history of the electric industry in this country -- maybe worldwide, but I don't cover the world, so I can't say that with certainty.

You also have efforts in the Northeast to try to limit carbon production. You've heard of REGI. REGI has established certain goals for the next ten to 15 years. REGI goals, if you look at what they imply, suggest zero load growth.

Many people have criticized REGI goals as being far too inadequate to achieve the kind of reduction we actually need. Again, if we're going to exceed REGI goals, we're talking about an electric industry that's going to get by in the future with less energy consumed and less peak load than we have today.

Barriers to demand resource investment. The history and literature discussing barriers to demand resource investment is very lengthy. I'll try to distill it into an easy phrase: Time, knowledge, tools, and capital.

The demand side of the meter does not have the time, does not have the knowledge, does not have the tools, and often does not have the capital in order to make the investments necessary to improve overall energy usage, and also improve the efficiency of wholesale markets.

I'll give you an example: If you think of a hospital, PJM has a lot of meetings in Wilmington, Delaware. You can walk down the street in Wilmington, Delaware, and see a hospital with single-pane glass windows and a rusted air conditioner in every one of those windows for four floors. I counted about 80 or 90 room-sized air conditioners.

It's unquestionable that changing out those windows and changing out those air conditioners, is an efficient thing to do. It would pay back the hospital to do it, but the hospital has other priorities. They're worried about staffing shortages, they're worried about patient care, they're worrying about how they're going to pay their electric bill, let alone get the capital, get the expertise, find someone who will come in, change out all their windows and change out all their air conditioners.

In order the achieve the type of energy reduction goals that the states are saying we want to achieve, and, I think, federal legislation will soon be saying we need to achieve as a country, those types of investments have to happen, and they have to happen tomorrow.

We need to reevaluate and redesign our entire infrastructure, based on as history of cheap energy in this country. I don't think cheap energy is in the future, and it's the transition to this new future, that all people have a role to play.

And now we come back to your role here as the FERC Staff in dealing with wholesale markets, finding appropriate price signals to encourage the type of investment that will make overall efficient use of energy and improve wholesale market design outcomes, as well.

I would anticipate further questions, and I know that will continue. Thank you.

MR. KATHAN: Thank you for all your comments. At this point, I will open it up to any questions. Commissioner Wellinghoff?

COMMISSIONER WELLINGHOFF: David, thank you very much. I want to thank all the panelists for their very insightful comments.

In talking about the economic benefits of demand response and the value to the system, there is one area that I didn't hear something that I had expected to hear some information on, so I want to ask some questions in that area.

Let me preface the question with a comment. I think a number that we all have to remember and be cognizant of, is 387; 387 is the number of parts per million we are right now in CO2 we are in the world.

That level is the highest level we've ever seen. I think it's very, very important to understand that, going forward, in this country, we're going to have to do everything we can to reduce that level.

With respect to that, demand response, I'd like to put that in a larger context, and the larger context is not just on the demand side, but on the supply side, what we're going to have to do to reduce that level of carbon.

One thing we're going to have to do, is move very aggressively ahead with all the renewables we can in this country. I get people coming into my office every other week, proposing massive wind projects. Maybe, Mr. Borlick, you can tell me, do you know how many megawatts of wind there are in the queue in MISO?

MR. BORLICK: I can't really.

COMMISSIONER WELLINGHOFF: I understand it's huge.

MR. BORLICK: It's in the four digits, right.

COMMISSIONER WELLINGHOFF: How do we expect that we can maintain grid reliability and stability, without massive amounts of demand response in the face of that massive influx of wind in MISO?

Wouldn't it be appropriate for us to look at perhaps payments over the level that you are discussing for demand response, to ensure reliability in the MISO grid?

MR. BORLICK: I would say no. What we would like, is for the demand response to reduce the need for that wind power. In fact, the two are really unrelated.

Wind power is replacing fossil generation in the region. It's not peaking, per se; it's actually an energy-saving device.

COMMISSIONER WELLINGHOFF: I understand that, but, ultimately, though, the wind power is going to have to not only replace existing fossil generation, but, hopefully, make up for new energy requirements in MISO, I assume, as well.

MR. BORLICK: Yes.

COMMISSIONER WELLINGHOFF: To the extent that that wind power generation could increase volatility, as it has in Texas, where we have already seen prices in Texas become more volatile because of wind, couldn't additional, quick demand response, reduce that volatility, and, in fact, make that MISO system more stable and more able to take more wind, in total?

MR. BORLICK: Are you saying "quick demand response"? Yes, indeed, but, in fact, what that's doing, is substituting demand response for regulation service.

COMMISSIONER WELLINGHOFF: Correct.

MR. BORLICK: That's exactly the problem we have with intermittent sources such as wind power.

COMMISSIONER WELLINGHOFF: That's correct. Wouldn't that be appropriate to pay demand response to do that?

MR. BORLICK: Yes, but you don't pay them a subsidy; you pay whatever the value is of regulation of service. The market for regulation will take care of that.

COMMISSIONER WELLINGHOFF: Wouldn't it, in fact, be appropriate, if we needed to get significant wind into the system quickly, to take care of the carbon problem, to perhaps pay demand response more, to ensure that it was available to stabilize the system?

MR. BORLICK: I know what you're trying to get me to say.

(Laughter.)

MR. BORLICK: Let me meet you halfway. I don't have -- I'm not a purist. I don't have any problem with subsidizing demand response on an interim basis, if you want to just prime the pump.

The problem with subsidies, is that once they are in place, the people that are getting them, fight like hell to perpetuate them, and this Commission has seen this just a few months back, with the PJM ICC case.

They were getting LMP twice, and they still wanted it, and they came through all these same arguments.

COMMISSIONER WELLINGHOFF: I understand your point, Mr. Borlick, and I appreciate your answer. If I could get maybe another panelist to respond --

(Laughter.)

MR. WOYCHIK: Commissioner Wellinghoff, thank you very much. I think some of my comments did respond in the form of saying that DR and the operating reserves market, as well as the capacity market, should have ramp rate limits and have specific incentives as market incentives for ramp rate.

DR is very fast, dispatchable ramping capacity in many forms. I can dispatch exactly against wind, and it is necessary to counterbalance all must-take resources.

California has a policy, in fact, to ask for more dispatchable ramping capacity, exactly for those purposes.

The question of whether you pay more than you need to over the economic amount, is a difficult one, but I think what we haven't explored enough, is just providing clear ramping performance requirements in market rules, so that, in itself, I think, will take us a very long way.

Then the question of what do you do beyond that, is, I think, a more difficult question, but the very first thing we need to do, is to provide ramping capacity in operating reserve markets.

In particular, in the capacity markets right now, you see slow, dirty, inefficient coal plants fulfilling capacity requirements. I mean, it doesn't make sense, from an economic or a policy perspective, so I think we would ideally start it at Step One and then address the second issue.

COMMISSIONER WELLINGHOFF: Mr. LaPlante?

MR. LaPLANTE: I think that in terms of wind and demand response, the first thing to do, is to look at the impact of the significant amount of wind penetration on the ancillary service requirements.

The first thing you might do, is, ask, do we need more regulation because of wind? Do we need more operating reserves, because of wind? Is there a need for a load-following market?

Once you answer those questions, I think you've got the products you need and then demand response, hopefully, will be able to participate in those markets, fully, and get compensated comparably with everybody else. That's sort of the way I would see it playing out.

I disagree completely with Eric's statement that coal plants shouldn't be in the capacity market. They're plants that are providing energy, they're capacity.

They can't provide operating reserves, but they should be in the capacity market; they shouldn't be in the operating reserve market, so I think those things tend to sort themselves out.

COMMISSIONER WELLINGHOFF: Thank you, David, I appreciate it.

MR. KATHAN: Bob?

MR. BORLICK: One more response to Commissioner Wellinghoff.

(Laughter.)

MR. BORLICK: It has to do with this whole issue of reducing CO_2, which I think was part of your question. The right answer, the economist's answer, is that we should be internalizing that cost, in terms of allowances, which get tacked on to the fuel costs of the generators, which, in turn, drive up the market price and we pay that same market price to the demand side, so they captured that.

However, in the interim, before those costs are internalized, it would make sense to roll something in on the demand side, to take care of that externality.

I would go that far, and that's not a subsidy.

MR. KATHAN: Thank you. Any questions from Staff?

MR. KELLY: I'm Kevin Kelly. I have a question for Dr. Woychik. You list a number of particular issues, eight points that you describe as being in the weeds.

I won't try to follow up on those here, but you said the primary problem that overrides them all, is the stakeholder committee voting process. That makes me think of two questoins:

One is whether -- how do you deal with that? The idea of stakeholders is to get all points of view, not to let one point of view dominate.

Yet, you know, you might yet, for your purposes, want a demand response point of view to dominate. So, how do you deal with that? That's part one.

Part two is, as you mentioned, in our proposed competition rule, we were trying to increase the responsiveness of RTOs to the needs of stakeholders, and create a voice, especially for minority stakeholders.

It sounds like you're familiar with the rule, so I won't embarrass you with the question of whether you think it goes far enough, or if there are additional measures beyond those proposed, that might be needed in the future to correct this problem.

MR. WOYCHIK: Thank you for the question. I think it's a great question. I think it's a very difficult problem.

I'd like to think I've thought through a lot of these things, and we could be in an enlightened dialogue and have a good answer, but, in this case, I don't.

If others do, that would be great. Please step forward.

I don't know exactly how you allow for the stakeholder process to work, which holds the existing interest, and, in essence, demand response is a new entrant it has very little presence, comparatively.

So, I think one of the ways, at least mechanically, to balance the voting, is to reduce the overall number of votes. The problem right now, is -- I know this is not something I'm comfortable explaining, but the holding companies have, the transmission companies, distribution companies, et cetera, they put a lot of votes down, and then a set of them, because generation is the most profitable element of most business models, in our RTO/ISO arena, they dominate the votes. To reduce the votes, allow DR to have at least some balance, I think would be one way to do it.

That means that you have maybe five votes, at most, on the committee. Then the question is, does it represent sufficiently, the stakeholders? That's the real tension.

I won't go further, because I don't think I have much better of an answer than that. Thank you.

MR. KELLY: Let me follow up then on one lead question. One of your points was that at least in one of the RTOs, you saw excessive metering and communications requirements. Could you expand on that?

How do you know when something is excessive? It seems to me, it may depend on the type of service provided.

If you're providing the equivalent of spinning reserves, it' seems to me you want pretty quick response, good metering and communication.

And what one of the needs that seems to be identified to give demand response respect, is that it's actually there and responds when it's called on, which seems to me to increase the need for metering. How do you know when the metering and communication requirements become excessive to the particular service being provided?

MR. WOYCHIK: Thank you. Let me try to use an example. We see in ISO New England, a residential program that's a radio-controlled program without a lot of metering and statistical sampling.

We can get even a five- or ten-minute view to New England ISO as to what they can expect, if they ask us to use out-of-FERC capacity for operating reserves, yet the requirements we have for metering, look much more like generator metering, which is very extensive, fully more like metering you'd use for augmented generation control.

We think we can provide the resource. Dr. Violette talks about particular methods of going back and doing annual reports to reconcile, and we have a track record that is very substantial and clear in providing absolute capacity that's very firm.

And when you do the analysis later, unfolds on a control basis, a sampling basis, the regression analysis, it's there. So, part of it is making RTO/ISO groups comfortable with that.

That's our education problem. But for us to always have to have the equivalent of generator-type metering, I think, is unwarranted and is unnecessary.

I'm very concerned about making sure that we fulfill all the needs for certainty, but when the costs far exceed the benefits, and we think we can provide all the benefits with much less requirement, then I would deem that excessive.

MR. KATHAN: Paul, do you want to add to that subject?

MR. PETERSON: I was going to respond to Mr. Kelly's initial comments about the stakeholder process, and offer just some quick observations.

One, I think there are some structural differences between ISO New England and PJM, that make the ISO New England process a little better. I'm not saying that Mr. Woychik isn't right to say that there's still a problem there. Those structural differences --

In ISO New England, we have six sectors in the voting governance structures. One of those sectors is called the Alternative Resource Sector, so there is a specific place for demand response providers, renewables, energy efficiency providers, to participate and have a block vote, if you want to think of it that way.

We also have the benefit, I think, in New England, of having -- I don't know what the right number is -- 95 percent of the traditional utilities, have divested all their generation interests. There are some remaining vertically-integrated utilities, but they are very small.

Whereas, in PJM -- and I participated in both of these stakeholder processes. I attend far too many meetings than I probably should.

In PJM, there are a lot of either vertically-integrated utilities, or utilities that still have subsidiaries that are generation providers, so it's sometimes difficult to know what interest is driving a particular vote in the PJM process, whereas, in New England, it gets a little more transparent.

The third thing that I think is different in the New England process, the state regulators are very active at all levels of the working group and committee processes, with staff people present. You get that input and that voice early on in the process, whereas in PJM, the regulators and the regulatory staff do not appear to be quite as involved.

All that said, I'll offer one example of some of the frustration that sometimes occurs in these stakeholder processes: We have been working in the PJM process on a proposal for incorporating energy efficiency in the RPM model.

And we demonstrated with a specific example of two customers, each ten megawatts, without doing energy efficiency, and both customers would pay a thousand dollars a megawatt-day. That would be their price coming out of the base residual auction.

If you were able to get a substantial amount of energy efficiency invested, that price would drop to $920. Again, it's a supply/demand curve. You change the quantity, the price goes down.

What we are proposing, is that if Customer A does more energy efficiency than Customer B, then Customer A's price wouldn't be $920; it would be something like $890, and Customer A, who did less energy efficiency, would pay $930 or $929.

The uproar over double counting, was such that no one wanted to support the proposal. They would rather all pay a thousand dollars than to let the other person get $899, if I have to pay $929.

That's the kind of stakeholder problems you sometimes run into, where people, because of some principle, some economic principle, or some unfamiliarity with what is being proposed, or just an embedded interest in maintaining volumetric sales or not disadvantage that, their generation will say no to something that would benefit everyone.

Both parties would be better off than paying a thousand dollars, but because one person is going to get an incentive, then the whole proposal gets voted down.

That's the example I'll lay down for you, and that's where people may come to the FERC to say, can you help us with this problem?

MR. KATHAN: Lawrence, did you have a comment?

MR. STALICA: I had an observation to answer Mr. Kelly's question about the stakeholder process.

I'd like to encourage the RTOs to continue. Recently, I've seen a greater focus on demand response.

There's a slight difference of assigning senior-level executive management to the DR discussion, to facilitate that discussion.

Andy Ott, I believe, is on the second panel, and is leading the DR discussion in PJM. I am encouraged by that.

At Midwest ISO, last month they had their annual meeting, and there were specific overtures from the MISO, to assign executive management leadership. I think assigning KPI key performance indicators to promoting demand response by these RTOs, is warranted on these individuals.

I'd like to see them go after demand response with the same fervor that they went after reliability pricing models in the forward capacity markets. We need that type of leadership from the RTOs, to do that. That would go a long way.

MR. KELLY: If I could just follow up on that, because I was going to ask you to expand on that comment later. You said that by the end of the year, you'll be licensed in five RTOs, and you were calling for senior management participation.

You've mentioned that, apparently, it's going in the right direction and you're happy with it, too.

Do you see progress in the other RTOs you participate in, or ISOs, in that direction, or is there a need for additional attention?

MR. STALICA: I look at PJM as the more mature -- not always the better ISO, but the more mature ISO, so the programs there, the reserve programs, the ancillary services programs, the capacity and the demand response programs, are more robust, they're more well defined.

I think what's happening in the Midwest ISO, with the emergence of the demand response program, is encouraging, but there's still a lot of questions.

We're registering for that program out there, but we don't know if we're going to participate, because, clearly, at least in my opinion, all the rules aren't defined. I think they're progressing.

As far as ISO New England, we serve one of our facilities up in Maine, we serve that facility and we respond to prices every day. We're at that plant every day and we participate in a response program up there.

I think they're doing a good job. We need to get all the RTOs to focus on what I believe are three areas: Energy; capacity, where there's a capacity market that exists; and ancillary services.

I'm not one to reinvent the wheel. I don't know if there's enough communication among the RTOs with respect to development of these programs. I would encourage that, as well, and pick and choose what the best attributes are.

When you're picking and choosing those attributes, talk to the load, talk to the people who are on the other side of the meter, who are trying to make the economic decision on whether to participate.

As you have those discussions, you know, talk to the load and not only to the electric distribution customers, but the general service providers, wherever you can. Get down to what's behind the meter.

I would encourage those steps, too, to take place.

MR. KATHAN: I have a question that Dr. Violette brought up, having to do with the CBLs or its customer baselines. I think Dr. Woychik also brought that up.

I believe you mentioned that there needs to be a way to consolidate the lessons that emerge elsewhere. I guess my question is, what are those key lessons? How should they be consolidated?

MR. VIOLETTE: I believe research has been going on in different places throughout the country, and, in some cases, that research is a little bit hidden, but I think that some of the lessons that are coming out of the CBL work, are that if you've got a program with a variety of customers in it, a single customer baseline method may not work.

We do have some choices. I think PJM offers a choice to participants in programs, to take a weather adjustment or a two-hour, same-day adjustment or to not take an adjustment.

But what we've seen in doing evaluations of particularly C&I customers in California, is that we have some customers where the day-to-day volatility is so great that you can't really specify an accurate baseline by using three days out of the previous ten or five days out of the previous ten.

You need to come up with something different for those customers. We tested probably 20 different customer baseline methods on that group of customers, and not a single one of them performed well in a backcast.

We simply couldn't forecast very well, that customer group. What we could do, is, we brought those customers together. They typically tend to be the larger customers.

We talked to them about putting some end use meters on the large pieces of equipment that they were using for load response, and that was a way to solve the problem and get a good customer baseline for those large customers that had high variable loads.

You've got a similar problem with customers that are weather-responsive, and customers that are non-weather-responsive, but I think we settled on an arbitrary approach to customer baselines.

Somebody, early on, said that we should use the ten prior days. Why the ten prior days? Why not the 15 prior days? Why not the five prior days and the five historic days? Why not the three prior days?

You know, even in the work that was done early on in the California Energy Commission, you picked this kind of ten-day window. What we've seen, are customer baselines that are more accurately estimated, by taking all the days up to the event day, so you're not having to wait to settle with the customers, many days after the event.

But you can benefit by, if it's a July 25th event, you can benefit by using all of the non-event days in the season, up to that event. We can produce better customer baselines, using that method.

It may be a little bit less transparent to the customer, but you don't want to trade off accuracy with transparency. We've been looking at approaches that use your ten prior days, and five post days, to make sure that the days are as close and representative to the event day, as possible.

It's not just the ten prior days that are good replications of the event day. A couple of days after the event day, may also be a very good replication, and bringing them to bear, can increase the accuracy of customer baselines.

Again, that approach has not been studied in lot of the well-cited literature on customer baselines, so I think that right now, just in the last few months, studies have been coming out on customer baselines.

I think that information can be consolidated. I'm not sure it has been consolidated yet, at least I haven't seen it.

I think we can do a much better job on customer baselines, going forward, which I think will make the markets more efficient. I think it will make all the parties in the markets, more willing to allow demand response to participate, because they believe they're paying for what they get.

Some of the backcasting that we've done, has shown that it's very difficult to estimate the load impacts on some of these programs. I think, for credibility, it's important that we do a better job.

MR. BORLICK: Could I respond?

MR. KATHAN: Dr. Woychik has a comment directed to him, also.

MR. WOYCHIK: Just real quickly, I was able to talk to Joe Bowring recently. He was very concerned about the gaming issue.

The proposal I offered, informally, so far, I think is very consistent with what Dan is talking about. We tried to talk about a specific set of baseline methods.

We see if there are some of those baseline methods that we can actually match with particular kinds of DR resources. Then there will be other DR resources that need additional metering, and we also need to address the metering issues.

I certainly saw some quizzical looks about whether using less metering, for example, for residential, is a good idea. I think all those things need to be addressed proactively, because we need to address the gaming issue very specifically and get that addressed, so we do have credibility and certainty, firmness of power, et cetera.

So I'm looking forward to working with Summit Blue and others and anyone else, in particular, our colleagues in the DR industry, so we can get these matters resolved.

MR. KATHAN: Bob?

MR. BORLICK: Just very quickly I agree with Dan, when he says baseline should be tailored to the particular customer. Even so, this is a daunting task. We're just getting into this at MISO right now, Midwest ISO I should say. We don't like MISO.

What we're faced with here is a metaphysical question. How much would they have consumed? The baseline will never tell you that. The best we can do with the baseline is not constructed in such a way that it's an unbiased estimate of the expected amount, the expected value of consumption.

That means by definition this is a stochastic process. By definition if you try backcasting it, the backcasts will never tell you it will never match the baseline. The best you can do is hope that you've constructed a baseline which will be as long in one direction as it is in the other, so that over time, the overpayments and the underpayments will kind of balance each other out.

That's about as far as I can go with backcasting, rather, with NMV functions.

MR. KATHAN: Dr. Violette?

DR. VIOLETTE: In response to that comment, I think it's a very fair statement to say that the customer baselines that we come up with will always leave some uncertainty in what the actual impacts of demand response programs are at the time.

I would also like to point out that there's quite a bit of uncertainty on generation resources. I was looking at some data, I believe, from New England. They put in the peak hours. They take out about a ten percent forced outage rate.

So they're assuming that on the list of generators that could be available during peak hours, that roughly ten percent of them may not be available. It's also true that when they call on generation resources, not all of them appear as expected.

When I look at the recent numbers that I think come from the best approaches, I think we're getting to about the reliability that we're seeing from the generation sector.

At least we're getting much closer, which is we're seeing demand response programs that can reliably deliver within ten percent of their target amounts. This is relatively new. This is coming about because of the automation of demand response, where either a market operator or the customer themselves can hit a button, use their energy management control systems, turn down non-essential lighting, set back the thermostat, and in many cases a lot of these customers are completely unaware of the event.

So we have seen much better designed programs that we can count on. I think we're coming a lot closer. If we can get the baseline right, one of the things we've seen is we've seen customers go in, do a lot of work on their programs.

They know they're reducing load because the baseline's estimate is so inaccurate they're not being appropriately paid for the work.

This is the big issue with the Demand Response Research Center out in California. This is what supported their research. They've automated a lot of buildings and they said they knew they were getting demand reductions, yet they weren't sure about it, due to the selection of the customer baseline method that was being used.

MR. KATHAN: David?

MR. BREWSTER: Just a response to Bob's point about it being a daunting challenge. It certainly is a daunting challenge, but I think there's been daunting challenges that the generation industry has faced in terms of having LMV and telemetry requirements and settlement procedures otherwise. We shouldn't let the daunting challenge be any sort of inhibitor for the demand response industry.

The other thing is all of our sites and most of the demand response sites in the industry have at this time new real time two-way communication. All of the data exists. It's not like the mass majority of these commercial industrial sites are being statistically sampled.

All the data is readily accessible. The challenge is just figuring out and tailoring a baseline accurately, to accurately judge the performance. But it's a challenge that's at our fingertips because all the data is there.

I think the important thing to do is to share best practices, as Lawrence was talking about. I think some of the RTOs and ISOs, I know their demand response groups are now forming. Therefore, stakeholder groups must look to themselves to sort of share best practices, because I think there's been a birth of sort of communication between the ISOs and RTOs to share best practices around baseline methodologies in particular, to come up with best standards with the industries. So I see some improvements there.

I think the key is for what others have said, creating credibility and reliability of this resource and again, all the data is there. I don't think the huge issue is addressing gaming. I think gaming has been way overstated in this industry.

I think there's some bad seeds that have potentially taken advantage of baseline methodologies. They should be perceived by market monitors and others.

But I think for the most part, customers are doing everything to do the right thing, and I think the data is all there to demonstrate their valid performance.

MR. BORLICK: Let me just add one thing. The difference between generation and demand response is that we can hang a meter on a generator and we know what the generator has delivered. In the case of demand response, we know what they consumed, but we don't know what they would have consumed but for receiving this payment.

That's the function of the baseline. On an ex post basis, the issue is much more clear for generation or even behind the meter generation than it is for somebody that's reducing the load.

MR. MURRELL: The way I'm kind of taking in all of this discussion about baselines and kind of processing this in my mind as relevant to the kind of day to day or hour to hour energy picture, when you think about ancillary services and how demand response might operate in the system to provide ancillary services, how does the baseline measure question apply in that context?

MR. STALICA: We were one of the first loads to participate in the PJM synchronized reserve market. I don't view the baseline as an issue. We have to submit 15 minute data for a period before and a period of time after, in that it's a cost of doing business in that market.

We're fortunate because a lot of our facilities or all of our facilities have that type of metering capability. I have been listening to the conversation on baseline. I'm not saying it's not an important problem, but just pick a way to do it and do it consistently, and make sure it's as fair as possible.

That will allow the customers unlike myself who don't have the ability to have that real-time infrastructure in place, to know what their performance level needs to be. I don't know if it's more complicated than that.

MR. BREWSTER: One key difference might be just to analyze results of the data feeds. Typically, we participate in New England, for example, at five minute intervals. In the PJM ancillary services or synchronized reserve market, we provide one minute data.

So it could just be when the ancillary services, where there's more obviously of a quick start requirement, then we get more granular with the data and we provide one minute data.

We can go more granular than that. It starts to become very challenging, back to Mr. Kelly's question on metering and demand response resources are helped by having a sort of remote, intelligent gateway devices and providing millisecond data.

Then it becomes cost prohibitive. With the technology that exists today, providing sort of one minute interval data today is readily available and affordable. I think that Mr. LaPlante could speak about the needs from the control room's perspective, but I think that more granular data meets the needs of the ancillary services.

MR. LaPLANTE: I think the baseline is a little bit easier in the sense of the ancillary service markets. You're measured it against if we need operating reserves within ten minutes. It's fairly easy to measure what the load was ten minutes ago. We can see if it's dropped.

The baseline problem is not quite as bad. There is an issue that loads may be naturally growing over time, over the course of an hour. It may be necessary to take into account that the load had reduced five megawatts, but it's continuing to grow. But it's five megawatts below what it would have been, had it not been activated for reserve.

I think that's a smaller problem than in an energy or capacity type product.

MR. KATHAN: Dr. Violette, you had a comment?

DR. VIOLETTE: Yes. Mr. LaPlante pretty much talked about what I was going to bring up. It's easier for ancillary services during the short period involved, and the fact that you have more recent data subject to the event.

But if you're looking at an event that lasts from 12:00 to 7:00 p.m., I think baselines become very critical.

They're critical for a number of reasons. They're critical to get customers to participate in the program. You have customers installing equipment in some programs and spending a fair amount of money on upgrading their energy management and control systems, and they get the energy savings that occurs. A signal goes to an energy management system and they turn off lights and reduce use of equipment.

Then they come back and due to the vagaries of the customer baseline that they happen to be on, they're not getting credit for what they're sure that they're delivering.

You know, again the Demand Response Research Center in California has been researching this, and I think has produced pretty compelling information. If we want customers to participate in these programs, we need to make sure that they get a return of what they're contributing to the program.

It's not clear that sort of what I would consider to be overly-simplified baselines are accomplishing that.

MR. KELLY: The title of the panel is "Value and Compensation." I have a question for a couple of people with a long introduction, so bear with my introduction.

At least in my mind, I've now divided the issues up into four bins on value and compensation. Here they are. You can comment on whether the bins are even right or not. But I'm going to end up asking a question about Bin 3, just to tell you where I'm going.

Bin 1 is there are issues related to retail customers, who see a rolled in average price and they don't see the market price, or they may pay the equivalent of $50 a megawatt hour at a time when the market price is 150. So they need to see the market price, and I take it that was Mr. Eber's thing primarily.

The second bin, probably expressed best by Mr. LaPlante, is that what wasn't the right value is the marginal cost to supply and the marginal value of the consumption reduction. Basically, that's saying that customers, the right price, the right compensation is deferred marginal cost.

Bin 3, that's where my question is. I'm going to skip over for a minute. I'll explain it last. Bin 4 is environmental costs, probably best exemplified by Mr. Peterson, who said over 20 years to reach our carbon goals, we need to have a lot more demand response and that's one way of doing that, is to include externalities in the price. You get the values of the externalities.

That raises political questions about whether if

FERC did that we're getting ahead of Congress, who wants to raise the cost of supplies as opposed to the value of demand response.

But Bin 3 is what I call "other." I've heard a number of miscellaneous statements that didn't mention environmental externalities but other values that demand response brings, that are not compensated.

Statements like well, the more you have demand response, the less you have market power; the more you have demand response, the less you need to rely on capacity markets.

Mr. Marlette said, you know, you need to look at the value of demand response over a season to get its total value. Looking at what I think Mr. LaPlante would identify as marginal costs right now in this hour is not enough.

There was also the statement well, demand response is more valuable than generation, because if you add a generating unit, it raises the marginal costs to everybody. If you have demand response, I guess you have to have a big enough incremental, and it lowers the marginal cost.

So there is a Bin 3 of things beyond paying the market price, but less than paying the environmental costs, which give a value to demand response that provides a lot of efficiency. Question. I don't want to ask all eight panelists to answer this or we'll be here all afternoon.

But I think I'll pick, at least for starters and others may weigh in, Mr. LaPlante and maybe Mr. Violette to start. I appreciate the value of those features of demand response. I have trouble seeing how to quantify them to include them in a price.

That's the question. Are these quantifiable, such that you could get to a right price of adding in an additional compensation. My friend Dick O'Neill, the Chief Economist, is on vacation.

I think he would argue well, they're already including price when you calculate the right marginal cost. You've inherently got all of those values for market efficiency.

Economists, they'll tell you that taking all the market values into account leads you to something other than marginal price. Starting with Mr. LaPlante, then Mr. Violette and anybody else who has a burning desire to weigh in on that, please do.

But if I asked all eight of you to comment, I think it would go too long. If you think my four bins are wrong, please chime in on that too.

MR. LaPLANTE: That's likely the longest question I could never answer.

(Laughter.)

MR. KELLY: I apologize. I'm trying to sort out my own thinking, and you've heard the result.

MR. LaPLANTE: The answer is in my mind I agree with what you said Dick O'Neill would say, which is if the prices are correct, these outcomes will happen. So if we get the prices right, the other benefits will occur.

The difficulty with getting the prices right goes back to Bin 1, I think. In those obstacles, that's where the problems lie. So we don't have full demand participation on the market, because the retail rate tariffs of other sorts of barriers to energy efficient like a renter or load barrier, where the renter pays the bills but the owner is the one who has to make the investment. You have those barriers to getting the prices right.

That's what prevents realization of those benefits. I don't think it's so much price adder. When you start adding that in, you're going to be paying for it. But I'm not sure that would get those benefits or realize those benefits.

DR. VIOLETTE: I think there are two issues that come up. One is that many of these benefits, such as market power, market efficiency I would argue, and some people would disagree with this, that if we improve the load factor of the industry in general we're going to be improving the productivity.

That's going to happen by improving the ability of the demand side of the markets to respond to price. I don't think we're at an equilibrium there at all. Some of our consulting engagements are with manufacturers of demand response technologies like Johnson Controls, Honeywell, some of the companies that manufacture energy management control systems.

They ask the question all the time, is this market going to be there? Is FERC going to get a new set of commissioners that aren't going to support demand response? We see PJM looking like it's supporting demand response to the DR road map.

We thought we were going to put in all these systems. We had the capability of putting all these systems in over a decade ago. We had to lay off all the people we had working on those systems, because the price response didn't come to pass as they expected.

So they're looking at this market with some trepidation right now. I think, you know, they're getting assurance, you know. I know a number of the manufacturers are going in and adding more demand response or load reduction control capability to their management control systems.

But they are concerned, and this is why the regulators and the market operators need to keep pressing the issue, saying this is an issue we are concerned about. It's here today. It's going to be here tomorrow, and I think prices do affect that.

I am concerned a little bit about some of the RPM options on the forward capacity market options, in terms of their duration. When you make the decision to make an investment on the private side, you're typically looking at 10 to 15 years, not just three years, the way some of these capacity actions are devised.

So I think the need to incent technology innovation is a major factor in promoting demand response and promoting efficient markets in the future. I think that has to be done. You have to press it right, and I think it has to be done through the regulators and market operators, to provide enough assurance that the technology companies will invest money, talk to their customers, get involved in the problem, and to a large extent outside of the residential markets, will fill in the stats.

They've stayed away from the market. They're just starting to get in the market now. If something happens to scare them away from the market, I don't think we're going to have the technology we would like to have.

MR. KELLY: Mr. Violette, I listened to your comments and your prepared remarks, where if I understood you right, you said you do want to pay the customer properly, and you don't want a formula that's too complicated.

But being the customer, based on the demand response provided in that hour, at least as I understood, this is the value that demand response would provide over a season.

I took it that you thought there ought to be a higher compensation based on some seasonal evaluation of the customer's demand response. If I have that wrong, tell me. But if I have it right, how would you go about valuing that and compensating the customer?

DR. VIOLETTE: That wasn't the point I was trying to make. The point I was trying to make was that if you're a resource planner at the end of the summer and you want to look at what you think you can get for demand response next summer, you also want to look five and ten years into the future.

I think it's very important for you to have as accurate a number for what you've got in terms of load impacts on the event days for that past summer. You may have five or six events in the past summer, and the relatively simplified approach is we take the customers.

Settlements are fine. They're good proxies. I think it's great to settle with customers on those kinds of metrics. But I think that at the end of the season, we can do a much better job actually showing what occurred on each event.

So it's really a planning function. I wouldn't go back. I think we're going to get different answers.

I think if added up the load impacts, as calculated by these customer baselines by settlement, and we do an end of the year analysis, where we aggregate data across events, we aggregate data across customers and customer types, and we use some of the more advanced regression methods that take all the seasonal data in, we will get a more accurate number.

I wouldn't go back and change what is paid to customers, but I'd take that more accurate number and I would use that for estimating what would happen next season end for forecasting in the future.

I think it's important we don't do that now, and I think we should. I think it would provide a lot of useful information, and I also think it would help alleviate some of the concerns that market operators may have about demand response not being delivered.

MR. KELLY: Thanks. That clarification helps. Do you agree with Mr. LaPlante that if all customers saw the wholesale market price, that that alone would fully incorporate all the value of demand response, not counting externalities for carbon and other environmental effects, and that would fully solve the problem.

DR. VIOLETTE: I don't think it would fully solve the problem today, and the reason for it is that I think we're moving into a time frame when we're going to see technology advance, and we've seen a lot of technology advance that's on the mass market side with thermostats and with the ability to see prices. We're starting to see what we call kind of automatic demand response on the C&I side.

I think we're going to need another big jump in technology to see that. When you look at the potential studies that we've done, we find about two-thirds of the perpetual demand responses in the C&I and the larger customer segment. We're not really getting that right now.

So in addition to getting the prices right now, I think we have to be looking forward into the capacity market, and having the capacity market extend to the appropriate time frames, so that the Johnson Controls, the Honeywells, the people that manufacture the software will continue their development of technology, so that five years from now, we're going to have an extremely reliable demand response resource that we can count on.

For most of the megawatts, a large fraction of the megawatts could be available in ten minutes, not two hours and not four hours. I think that's the future.

To get to that future, we have to ensure that we provide the incentives that the people that are going to go into the market with these technologies, that they have a reasonable assurance of getting an appropriate return for their investment.

I don't think that's just based on getting wholesale marginal costs today correct. I think we've got to look down the road and say we need this saleable resource. We need it in ten minutes. We need it to be firm.

We've seen pilot programs where we've achieved that. Now we've got to take those pilot programs and get into the market with those programs.

MR. KELLY: Dr. Woychik.

DR. WOYCHIK: Thank you. I agree with everything Dr. Violette said. I would add a couple of things. One is that just like generation, DR should be able to get concurrent benefits. That means if fast ramping capable, demand response resource should be able to play in the operating reserves, call it the synch reserve. It should be able to get capacity benefits. It should be able to get energy benefits and congestion, and then losses.

The other value components for environmental distribution, to the extent it displaces the need for capital as well and/or costs, I think come in other jurisdictions.

I think that overarching demand response has an optionality, an option value that's much greater than other resources, to the extent it's more flexible. That is going to have to be formulated in the market itself.

But because it can't respond flexibly, it can respond when rules change. It can respond when conditions change. If we get these other details worked out which are very important measurement verification baseline, and we just facilitate the market rules properly, we need to also sharpen the prices properly.

I am not an advocate of capacity market prices as uniform prices being the right price. I do not think those are correct. It's about the details. Again, I think we need to get in the weeds, get those details worked out, and I don't think -- I'm not one to suggest that Hamrich wants subsidies.

I agree with my colleagues. We want to be comparable. We want to stand on very firm ground. But without the pieces working properly, and without the ability to pinpoint benefits, I think we'll have that capability and we'll be recognized as having a very option value. That's what I hope is the vision for the industry.

MR. KELLY: Could I follow up before recognizing somebody else? You were making a case that demand response is more valuable than generation.

That's the valuation piece. I didn't hear you say on the compensation side though that demand response should be paid other than the marginal cost on either capacity or generation, as determined in the common market between generation and demand response.

DR. WOYCHIK: That's correct. I see that as something that comes out of the financial markets basically. When you go to capitalize a power plant or a demand resource, there's going to be higher value and greater flexibility indeed for a demand resource, and because of its environmental benefits, etcetera, and its ability to be used flexibly.

I see that as value that comes outside of the traditional marginal cost pricing. For example, that it can displace distribution revenues. That's not in the wholesale market.

MR. KELLY: But I'm trying to see what conclusion I should draw from that. If I were a state commissioner, you might be telling me that if I had some kind of mandatory resource planning process, I should favor demand response over generation, and that I would get.

But as a FERC staffer trying to draw a conclusion about what FERC should do in market design, I am not sure what the conclusion is.

DR. WOYCHIK: My conclusion is, and I would offer it to you and ask to you consider it is get the pieces of each of these markets to work properly, and I think the other point that Dr. Violette made is that a fast, and I won't call it ramping capacity, a ten minute market that can really operate quickly and deal with dispatching against wind and other renewables, be super-reliable and meet all of the ISO-RTO operating needs.

I think it comes to the details, and sharpening the prices. I think we just need to fix the set of things that are on the table. But we don't need and shouldn't ask for additional incentives.

MR. KELLY: Thank you.

MR. KATHAN: Let's start from my left. Lawrence.

MR. STALICA: I wanted to understand the question Mr. Kelly asked. I think he asked the question does retail load need to see wholesale prices in order for demand response to be effective. Was that the question that you proposed?

MR. KELLY: No. I was saying where it doesn't see the wholesale price, that's Situation No. 1. Where it does see the price is Situation No. 2. Where load sees a price above the marginal cost, to take into account some of the market benefits is Situation No. 3.

And where demand response sees a still higher price to incorporate externalities was Situation No. 4. I was trying to find out how people believed in Situation No. 3 and how to quantify it if they did.

MR. STALICA: I'll go to Situation No. 1, which seems a bit easier. I think we've all had a little difficulty articulating how to do No. 3, but I'll offer a suggestion.

First of all, I think demand response can absolutely occur and is valuable in jurisdictions, states where you have unregulated rates and you're in an organized market and RTO footprint. We do that all the time right now. I have facilities in regulated states that are providing demand response and capacity directly, even to the RTO.

That brings a benefit to the system, and to everyone on that system, by providing that capacity resource or providing that demand response. We need to encourage that and we need to be aware that we need to remove any roadblocks from electric distribution companies in those states, to prevent us from doing that. That's my first comment.

The second comment. I do believe a megawatt of demand response is more valuable than a megawatt of generation. There's a variety of reasons. Generation becomes unstacked, Environmental considerations, not having the iron in the ground and how do you compensate that?

It's a difficult question. I think there's some discussions going on now in PJM, based upon some analysis work that's been done by the PJM staff on setting what amounts to a market threshold or trigger, above which that trigger there is no GMT offset, which in my mind that's the incentive payment above the LMP price.

I think we need to continue working on that analysis, get it right, and when the market is going crazy and prices are rising above that threshold price, and removing that GMT offset will help bring additional demand response in play.

So that's one simple way I think that we should look at and recognize that value.

MR. KELLY: Could you elaborate on that a little bit? I'm not familiar with what PJM is doing in that area, and I'm not quite getting your point exactly.

I think you've hit on the key to my question, on how do you compensate response, say above the normal market clearing price, whether you should and if so, how you would quantify it.

MR. STALICA: I could try. I'll do a poor job. I would encourage -- I don't know if he's here yet, but I would encourage him. PJM, I don't know if it's being done every year, every period of time. We'll look at what that threshold price is, where demand response is providing the most value.

I recognize that by not having the GMT offset. That's as much indepth as I can go.

MR. KATHAN: David?

MR. BREWSTER: That makes a lot of sense. I want to sort of continue on Eric's comments about fixing the pieces, and whether or not subsidies or incentives are required today.

As I said in my comments, we fully think that once barriers are removed and demand resources are able to fully participate in markets, there isn't any need for subsidies or incentives. At that time, you'll have a dynamic interaction and you won't have that need.

But at this point in time, virtually everywhere there are substantial barriers to participation in the market for demand response. You'll get a place like New England, ISO New England.

There's a mature market and the energy market's demand responses aren't able to fully effect real time prices, because they're not fully integrated into the real time market.

So you're never going to get the right price. If you're not allowed to be fully integrated in the market on the demand side of the equation, where the buyers of electricity are not able to participate in downward prices on prices by participating in those energy markets, until such time as those barriers are removed it's absolutely right to provide market incentives that create and reach the pump or whatever the expression we used. Prime the pump to get more customers involved in these markets.

I think that there's been ample studies and analysis done. I point to PJM's market monitors report from December of 2007, which really looks at the costs of these incentives relative to the benefits they provide to the system.

It's an overwhelming positive solution, and I think it gets to Paul Peterson's point earlier, that I think we have reached this unhealthy state where nobody will accept anything that is being considered a subsidy, even if it makes the market more efficient.

I think there's ample evidence to show these incentives do make the market more efficient, and at this point in time, they're appropriate.

MR. KELLY: So is a fair summary of your point that if customers were to see the market clearing price, you wouldn't need incentives/subsidies? But where they don't, the quote "incentive" you're advocating is something that moves the price they see at least closer to the market clearing price, and therefore you see it as not a subsidy but an efficiency gain.

MR. BREWSTER: That's right. It's an appropriate market incentive to get customers absolutely where there's a fundamental disconnect between the retail and the wholesale.

MR. KELLY: So you wouldn't pay the market's clearing price plus an incentive on top of that; is that correct?

MR. BREWSTER: I think that it could be appropriate in cases like PJM, where particularly if you're above a threshold point. I think if you're going to pick a threshold for the price of where you provide an incentive, that threshold should be used to determine where the incentive is cost effective.

If you're above a point where providing cost-effective market incentives to customers, that they respond and that benefit the entire system by bringing down the costs to all ratepayers in the system, it absolutely is appropriate.

MR. KATHAN: Jim has been trying to say a few words.

MR. EBER: I just wanted to clarify my position and to speak real quickly about whether a retail customer faces smarter prices that change hourly or regularly, or that same customer is on a fixed price and has a bridge to wholesale value, that allows them to get the value out of participation in the demand response program.

To me, both of those situations should lead to a relatively similar amount of demand response, as long as there's no barrier for that customer to participate.

I don't have a preference in whether that customer purchases at a market-based price or purchases at a flat rate, and has a market mechanism to get the appropriate volume.

I think that's pretty important. I think with the diversity of our customer base, you want multiple options. You want customers to have the ability to manage a complicated retail rate structure, to have access to that. But you also want those that aren't quite in that position, to have a little simpler path to the market.

MR. KATHAN: I'd like to follow up with Jim a few moments on this, since you're the only load-serving entity. Lawrence you are also, sorry, large holding company or large electric utility at the table.

What has been your experience? Like you're talking about the various types of customers and being able to participate, since you had legacy demand response programs prior to joining PJM, what has been your experience on how you've been able to do that from this linkage you're talking about, as you coming from PJM?

MR. EBER: Like you said, we started well before we joined PJM. It was a transition. It was a transition from basically cost-based incentives to market-based incentives.

The structure of the programs vary slightly, but what we tried to do is create as many options for customers to participate as they can, as we moved into market-based structures, making sure that the customer sees the market-based incentives as the incentive to participate as opposed to, you know, what had historically been some cost-based incentives.

I think now what you're seeing, as the market's evolving, in the capacity markets, as the values have been increasing, participation in those markets has been dramatically increasing over the last year or so.

MR. KATHAN: Bob, I think you were first. Then Paul, then Dr. Violette.

MR. BORLICK: I almost don't know where to start here. Let me take the easy one first. I think that the cost-benefit study that Lawrence was talking about that's being done within PJM regarding this GMT charge, what they essentially do is look at the impact of the lower cost on the total market, and count up how much consumers save, even the ones that they don't curtail their load, how much they save by that price reduction. Multiply for all the megawatts hours sold.

Then they look at what the subsidy payment is, the GMT payment that they make to the curtailed loads, and compare those two numbers. They say "Well, as long as we're paying out less, than consumers in general are gaining from this price reduction, this program is cost effective."

That's not the way any economist that I know of would go about doing a cost-benefit analysis, because it's true that consumers do in fact gain by that price reduction. But they gain at the expense of the generators. Every dollar that they're getting is a dollar that the generators don't get, and basically when you net those two out, it's zero.

Why would you think that a consumer should be advantaged over a generator? They're both market participants. So you know, it's an issue of robbing Peter to pay Paul, and that's not economic efficiency. That's an equity issue.

Where the economic efficiency comes in is when you change the resources involved, when the loads curtail and they displace generation, and they displace fuel. They may displace capacity. Those are real costs.

Those are resource costs. What they lose in terms of the value of what that electricity could have produced for them in terms of productivity or cooling their homes, that's a real cost mostly.

So you have to take those two things into account. So I don't buy this idea that one of the big advantages of demand response is that it can reduce the market price for everybody, because it has this corresponding effect of disadvantaging the generators.

The generators are going to get that money back one way or another. You can do it to them in the short term, but when the day comes that you have to build a new generating plant, you're going to pay them all that back in the capacity payment.

Let me go after this flat rate versus the tariff. I agree with Dave LaPlante that marginal costs of supply should be equal to marginal value of consumption. That's the right answer. The ideal way to do this, at least the economic demand response, is at the retail level.

The most efficient way to do this is for the state commissions to put into effect, or the LSCs to put into effect rate designs that wholly expose the customers to the locational marginal price, that pass the wholesale price right through to them.

I think that's the right answer for any C&I customer above, say, one megawatt. There's no reason why they should be looking at being served under a flat tariff vast market. That's a different issue.

But even there, I believe that Commonwealth Edison has a program in place that is going to put in retail real time pricing for residential.

Market power, I guess you could make an argument here that you'd want to induce more demand response because of the effect it does have in controlling market power.

But from what I've seen happen in the two auctions, PJM and ISO New England just giving demand responders a capacity price, a capacity credit that's equal to what the generators earn seems to be doing the job.

I think we should go down that road first and see how much demand response it induces into the market, and bring forward and, as market power is controlled, the natural thing to do is to start raising the price caps on energy.

As you do that, you're going to end up attracting even more demand response, as more people go up their demand curves and make the whole demand curve for the industry more elastic, which in turn further controls market power.

It also reduces the need for capacity payments and ultimately we're going to be able to get rid of the capacity payments maybe, if the market designs don't prevent that.

I think that's about it. I think I've covered all the points here.

MR. KATHAN: Paul?

MR. PETERSON: I'm going to get back to Mr.

Kelly's original four bins and the question of the third bin. I think the four bins are a useful construct. I'm not sure though exactly the way I would describe them.

But I think it's a useful way to separate things. Bin No. 3, there are a lot of studies. I'm not sure how much the dispute is, although Mr. Borlick may have some questions about it, that more demand response improves market efficiency.

We've spent a lot of effort over the last years trying to construct the demand curve, trying to figure out what a real demand curve would look like. The reality is we do not know the marginal benefit of consumption.

We try to construct these demand curves, but we really don't know. We're just guessing, and I think the strategy should be to allow mechanisms or provide mechanisms to allow greater participation of actual demand.

We will learn what that demand curve actually looks like, and in the process of allowing that participation, those mechanisms may provide some small short-term incentives or subsidies. All these words people like to throw around. I just like having those mechanisms to get more demand participating.

If you get demand participating, we will learn the answers to these questions that we're now arguing about as economic theory. I would point to Joe Bowring's December report, where he stated unequivocally that the benefits of the economic load response program vastly exceeded the $17 million in incentive payments that were made.

He argues that you don't want to be subsidizing or providing incentives. He's a good economist and he makes those arguments. But he also states that small, targeted transparent mechanisms can be appropriate under certain circumstances. You just have to be clear about them and not hide them, so you know about how to go back and fix them later.

I would make one last observation on Bin No. 1, where we're going to put all retail customers on real time rates. I think that's an excuse for not acting. That's saying it's someone else's problem, so I don't have to worry about it.

I think retail rate reform is important to do, and I think it's important for FERC to make mechanisms available in wholesale markets and it's important to do lots of other things. I don't think it's either/or. I think it's all/and.

MR. KATHAN: Dr. Violette.

DR. VIOLETTE: I want to go back to your question about Bin No. 3. The only way I've seen Bin No. 3 actually produced quantifiable Estimates is in a long range 15-year planning scenario, where you can actually look at revenue requirements of using that in kind of a regulatory context.

But if you're in a deregulated market, you're looking at the amount of money that customers need to pay to get the electricity to meet their electricity needs. What's the lowest cost way of doing that? It's a resource planning function.

If you put in demand response and you integrate it in the same way that you do generation in a resource planning context, you'll see that there is diversity. You can see that demand response doesn't use fossil fuel, and you can fit that into the model.

You can see that demand response has some flexibility. It's more easily moved from one year to the next year, or ramped up a higher level or ramped down at a lower level.

Now the generation plant is, once it's built, you have that 100 megawatts, 200 megawatts of capacity. It has low capacity capital costs, which gives you flexibility and it's located at the load center, so that it reduces some of the issues with T&D.

You can quantify the option value for demand response, but it's also important to recognize that there's an option value for gas-fired peaking generation. What you want to do is look at those low probability high consequence events that happen every three to four to five years.

We seem to have a one in ten event every three years now, and you know, you can plan those ENS scenarios and look and see what mix of these forces will allow you to meet that reliability scenario or that low probability high consequence scenario at the lowest cost.

You can sum those up, give a low probability and you can come back with an estimate of what the premium demand response might command in that future. We have done that, and we have calculated those kinds of numbers before.

In general, demand response looks very good up to a certain level. Then the value starts dropping below the resources. The old axiom is that you can overbuild any kind of supply. That's as true of demand response as it true of natural gas peaking plants.

The other point I wanted to make quickly goes to Jim's point about some customers do want flat rates. So how do you manage the risk associated with those? In long-term planning, you can also look at risk mitigation being there.

But some of the parallel evaluation studies we've done, where we've looked at day ahead hourly pricing. Day ahead isn't an actual real time wholesale prices, but it seems to be what customers need to kind of plan and to react appropriately.

We've compared the effects of day ahead pricing to the effects of say an air conditioner load program, and we find that you are able to get a reasonable proxy wholesale price signal through by economic operation of some of these event-based callable programs.

You can do this in such a way as a utility or an operator. You're relatively indifferent between the two.

The big advantage from pricing that we've seen in the modeling that we've done is that it allows the customer to get a benefit every day. Every day when it's hot out, they know prices are going to be higher in the three o'clock to seven o'clock time frame. So they shift and they save a little bit every day.

The amount they save every day, when you take it across the entire summer, it turns out to be a pretty big number. Then those pricing really allow you to respond to those emergency conditions, the reliability conditions.

The answer is probably not. So the work we've done shows that there's room for pricing. Pricing accomplishes a lot, but there's still room for reliability-based and event-based and load management type demand response programs. They control and they can actually reinforce each other.

MR. KATHAN: Jim?

MR. EBER: The only thing I wanted to add in the discussion of subsidies is when Joe Bowring talks about subsidies, he does state that they should be well-designed, which was referenced. But he also states that they should be temporary and having an expiration date, which is an important concept.

MR. KATHAN: David, did you have something to say?

MR. LaPLANTE: Sort of a related topic. How would we know when we had enough demand response, and with the response that we've gotten in the New England markets, we started thinking about that.

Demand response that we've been talking about around the table is like a peaking unit rather than a baseload unit, and one wouldn't want 30 or 40 percent of one's resource base to be demand response.

I think one of the challenges I think we have is figuring out the right amount of demand response. It's going to require, as Dave Brewster was saying, better integrating into the energy market.

Right now, with the sorts of reliability triggers, if we have a lot of demand response, we're going to be calling on the demand response a lot of hours, to maintain reliability if it's a large proportion of the system.

That's sort of an inefficient way, I think, to get there. It would be a lot more sensible if the demand resources were priced and resources that we're really doing for a lot of hours, could submit a lower energy price and resources that could only interrupt a few hours would submit a higher energy price.

That way, we could figure out what the right amount of demand response is. But I think we're sort of going about it. We may get there. Right now, we're sort of stumbling along that path and we may end up -- the smooth way to find out what the right amount of demand response is is to price it above capacity and energy. Then we may get there.

MS. WHITE: I had a follow-up question for what you just said about the customers who can shift by pricing on day ahead, and they can shift their loads and shift their costs, but then they're not necessarily available for reliability events.

It's been a concern of mine for a while that demand management only gets called on in emergency situations. Whether you would lower the frequency of demand response being called when you're up to the brink, if there were more customers on price-based programs who were automatically shifting their use from high peak periods, where it costs more.

DR. VIOLETTE: Yes. There's no question that if you have a pricing program that reduces overall peak demand, that should lead you into a regime where you don't have as many emergency events. We've done some modeling of some utility systems to see.

We've put real time pricing and we've put the price elasticity in. But again, we found the customers saved a lot of money, but they tended to save a lot of money on kind of every hot day in the summer, not just the event days.

But we were surprised at how little the impact had on the number of events called. It reduced them. That may be from about seven events to five events, and those five events still tended to be very high consequence events that cost the system a lot of money, and those event-based demand response programs still came out very well financially at a benefit-cost ratio.

I'm less convinced. I used to think that pricing solved all problems, and I went into the project thinking that that would be the case. If we just get the pricing right, everything happens okay.

But what I found is that pricing is for short-term markets, and we also need kind of this ability in forward-pricing markets. We've really not generated visibility in forward-pricing markets because we've only gone three years out. Most of these investment decisions are much longer than three years out.

Certainly from Johnson and Honeywell and technologies companies, that are thinking about hiring 2,000 engineers to do nothing but create a software that is going to help customers manage their load. For them to make that kind of investment, they want a return and they turn to consultants, like some of the ones around this table, and say what's our return going to be?

I say that's a good question, because I don't know what the demand response market is going to look like in five years. I'm hoping they will be integrated, that we're going to have automated demand response and that's what they're going to offer, that they'll get credit for their ten-minute ramp up time.

They'll get credit for the fact that they'll be much firmer than they are today. You don't need to discount them, and we discount generation too by the forced outage rates. So that's no different than what we do on the demand side.

To get back to the original question, studies have shown that pricing does a lot for customers but boy, it's great to have in your back pocket some event-based demand response that you can call three or four times a year.

In general, what we found is that if we have one percent of your hours, whatever megawatt is in one percent of your hours is almost always cost-effective.

It can go to two percent, but it's not worth building a combustion gas turbine to meet demand in one percent of the hours, probably not in two percent of the hours, but somewhere in between those two. The model says as a rule of thumb that's what we find.

DR. WOYCHIK: Reinforcing that, a program that Mr. Eber is involved with and certainly Converge is, and for ConEd there's a little program related to PECO.

We wanted to put out residential real-time pricing, which is voluntary, provide an equivalent of auto DR, which is price-based on a price trigger, and provide a dispatchable component as well which is fully dispatchable.

All three of those are options which any single customer can take with notice, with education, with a website interface. To me, that's an optionality that's very attractive for customers, that then allows the non-firm pricing aspect to be used in the very firm offer DR or dispatchable ramping products to be used all to the same customer.

I think those are certainly possible. But I think that helps maximize the value as well and gives the customer I think the ultimate portfolio of products, at least as we see it right now. I don't know if Jim wants to comment. Certainly, we're pleased with it.

MR. EBER: That's the equivalent of taking that residential customer and having the price response resource essentially act like an energy resource, and have the ability to dispatch that air conditioning cycling as a capacity resource as well. So you're providing both of those resources, similar to other C&I demand response.

The other thing I wanted to state too is that when you have price response in load or efficiency that get ultimately backed into your planning process, you essentially end up with the same relative level of reserve margins.

So on a hot summer day, you're going to be in the same place you were prior to that happening.

MS. MORTON: I'd sort of like to skip back to some of the opening presentations. It seems that a lot of the discussion we've been having is a continuation of discussions that have been going on for years, about true value of DR, what's the right compensation, how do you make the market efficient, all of which are critically important, very important to us.

But one thing that struck me particularly in the opening presentations was your message, Mr. Peterson. Perhaps if I mischaracterize it you can correct me.

One of my take-aways from your presentation, and I think Mr. Wellinghoff perhaps picked up on some of that too, is on top of all of those existing questions about how to get this right, and what are the values in the market of DR, there are those who believe that we're on the verge of a tsunami, a revolution, whatever you want to call it, in terms of how we societally deal with meeting our energy needs.

I'm curious to hear from some of the other panelists if you think that is the case. I think I see a lot of evidence that that's the case, and if you do think that's the case, how should or should that inform us in terms of the urgency with which we approach this issue, and how much we expect in terms of the precision of an answer?

We can spend a lot of time on discussing exactly what the right compensation is, what the marginal value is of the compensation. But if you do believe that we're sort of on the brink of a pretty fundamental sea change in how we meet our energy needs, I'm just curious on sort of how that informs us.

I was particularly struck, Mr. Stalica, by the story of your company. Here's a manufacturer and it makes sense for you to actually become a load-serving entity. Markets are so complex, but nonetheless that your company has done this calculation and that makes sense for you in a market that's become this complex.

Yet we may be facing a revolution in how we think of things. How on the regulatory front do you folks think that should inform us in terms of both the speed with which we progress and the precision we demand in getting the right economic answer?

MR. BREWSTER: I'll jump in one thing. This is was out of self-interest, but having third parties in the market is an important thing. We talk about the complexity of these markets. It's not the core competency of a hospital or a hotel or a university or a home owner to manage these complexities, nor is it necessarily the expertise of the utility to go behind the meter and help customers really deal with these issues.

Having third parties participate in these markets and have an active role in these markets to work with these utilities to guarantee aggregated uses to provide these services and working directly with the end users to take complexity off the table, to take risk off the table, to provide technology and automation I think are all critical components.

A second point, I think, and Mr. Wellinghoff hit the nail on the head, the most radical thing we're going to need to do is have a lot cleaner energy sources, and the cleanest energy source as we know it right now that are available are the renewable energy resources.

We have extremely aggressive renewable portfolios in the states, and we're going to see a huge onslaught of development. If you look at Texas, they're doubling their wind capacity this year alone.

I think that creates a huge challenge for our society and for grid operators in the utilities, particularly in managing these renewable resources. I think that as regulators we should be looking at demand response as something to really help regulate that, and all other quick-starting resources to help regulate, because I think the system is going to become increasing complex and volatile with those renewable resources. That creates a real challenge.

Then the final point I'd make is just to reiterate a point that Paul Peterson made. Let's not let perfection try and spend all this time on the sideline, figuring out in the economic sandbox the best appropriate measures to compensate these resources.

Let's get these resources in the market. Let's engage end users to be active energy participants. Let's learn from what we've done and fine tune as we go. Rather than not having or having an underdeveloped demand side of the market, as we try and figure out the optimal economic ways of a plant.

I guess we should keep doing what we're doing, but do more of it and do it faster. I think we've identified the problems. We need to work in the markets to get the prices right. I think all of the regulators have to help take down whatever barriers they can, both on the demand response side and the area that would get to the problem.

You were talking about there's really more energy efficiency than demand response. What we're talking about around this table will help reduce capacity needs and keep prices low, but it's not going to fundamentally change energy consumption.

That's really -- barriers to energy efficiency are different in a lot of ways. That's really identifying those and coming up with programs for removing those barriers. I think that's probably a lot more of a complex problem.

It's very difficult, because we have a whole society that's been built on a certain level of energy prices, and when we change the way we use energy, it's a huge challenge.

MR. KATHAN: Paul. Paul was mentioned.

MR. PETERSON: I want to acknowledge that I think you did capture the gist of my comments. I'd like to use the word "transformation." Tsunami and revolution sound like a lot of people are going to be dead.

(Laughter.)

MR. PETERSON: I think that's a very optimistic viewpoint. That optimistic viewpoint is really a distributed grid. I look at the telephone industry and I don't think anyone could ever have predicted how fast cell phones took over the industry and now they're talking about land lines as being kind of a dead industry.

I don't think the electric industry has become a dead industry, but I think it needs to be ready to be transformed with the idea of that individual sites, whether it be residential sites or commercial sites, are going to start producing much more of the power that's needed.

The future is a decentralized grid, that has millions of small power sources feeding into a single system. We think of supply and demand as being opposite sides of the fence. It's really supply and demand together, being balanced by ISOs and RTOs every hour, every minute of every day.

Where's the balance in that system?

The transformation is going to be on the customer side, when customers start generating more and more of their own power from a variety of ways and technologies I don't even know of today.

MS. MORTON: I think I share most of your views. I will say that I absolutely love my 1920's candlestick phone, which I still use every day.

MR. KATHAN: Dr. Violette, you have the last word.

DR. VIOLETTE: I'll try to make this very brief. Working for integrated utilities, the way that they do planning in the past two years has changed dramatically from the way they've done resource planning five years ago.

They're extremely concerned about risk mitigation. They're extremely concerned about siting, even gas peak plants are having a hard time getting sited right now. If they need any transmission upgrades, those are difficult to get.

I know of a couple of gas plants, natural gas peaking plants that were planned that have been taken off the drawings board right now. We work with these integrated utilities in risk management, on fuel costs, on whether these plants can be sited, and whether they can build the capacity they need to build in a number of years.

I always wondered kind of where is that being handled in so-called organized markets. Who is looking at kind of risk management, you know, five, ten years down in the future as prices -- well, will the market automatically handle all those things themselves, or is there a need for some kind of long-term planning to be done, not just on transmission, which all of the ISOs do, but on the generation side as well?

I think the history of the industry has been that we can and have built our way out of a real problem. Every time we've had an upswing in growth of the electricity demand, we've been able to build more coal plants and more natural gas plants.

We've built a record number of plants in the 1990's that use natural gas. I think we've hit a change, in that the industry is going to have a very difficult time building its way out of the situation that we're in right way.

That means we need to look very carefully at alternatives such as demand response, energy efficiency and the role that demand response can play in making energy efficiency much more economic.

All of the auto DR programs that are talked about in the C&I sector would benefit tremendously being integrated with building, commissioning programs, retro-commissioning programs, a whole host of very aggressive energy efficiency programs that don't consider demand response as an element of their program.

We could double the cost effectiveness of those energy efficiency programs and deliver demand response, and probably have the price. If that's an opportunity, a tremendous opportunity that we're missing, I'm not sure that this body can do much about that. But you look at it as an outsider and you think well gee, this really don't make sense.

MR. KATHAN: I think we're out of time. I'd like to thank all the panelists. It's been very informative. With that, we'll break for lunch. We'll come back at 1:15. At 1:15 we'll start two panels on barrier and solutions. Thank you very much.

(Whereupon, at 11:45 a.m., a luncheon recess was taken.)

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

(1:15 p.m.)

MR. KATHAN: Good afternoon. Let's start the second half of this technical conference. This afternoon, as I mentioned earlier, we have two panels.

The first panel is on "Demand Response in Organized Markets: Barriers to Comparable Treatment and Solutions to Eliminate Potential Barriers." This panel, the first one, will be focusing on the PJM, New York and New England markets.

A latter panel will focus on California ISO, Midwest ISO and the SPP region. One thing I'd like to encourage all panelists is that we are focusing on future reforms. We are wanting to look at what barriers still exist that aren't being address in the NOPR, and what potential solutions could be done to take care of those.

We'd like to hear any thoughts on that, particularly ones that directly relates to what we as a Commission can do. Why don't I start off with Commissioner Anne George, with the Connecticut Department of Public Utility Control?

MS. GEORGE: Thank you very much. Good afternoon everyone. I am the Commissioner from the Connecticut Commission; also past president of the New England Conference of Public Utility Commissioners, and NECPUC has asked that I come down and speak to them as well. I am also the current chair of MARUC's Electricity Committee.

So while president Smith spoke earlier about NARUC's involvement in these issues, I will just briefly touch on those as well, and support her comments from earlier today.

What I find interesting, and I found it interesting from this morning, is the debates and conversations we are continuing to have on demand response. It can't necessarily be isolated into the wholesale world versus the retail world.

The interplay is inextricably intertwined in a lot of ways. So I would try to focus on the wholesale areas, but we can touch a little bit on the retail areas as well. The New England states have long supported demand response programs, both on the retail level and the wholesale level individually.

The states have created and implemented great design changes, metering initiatives and incentive programs to enhance the development of demand response in the region. Collectively, the states have worked with ISO New England to develop rules that facilitate greater response in the wholesale markets.

A prime example of that, which I know you've heard a lot about, is the treatment of demand resources in the forward capacity market. In New England, approximately 2,500 megawatts of demand response cleared in the first four capacity auctions, and another 850 megawatts have expressed interest in the next forward capacity auction.

The amount of demand response in the first auction was a primary factor in driving the auction clearing price to the floor, as it should, when load has an opportunity to respond to price signals in the same way as supply resources.

During our regional debates on the creation of the forward-capacity market, NECPUC was steadfast in its arguments that demand resources should be comparable to supply resources. Beyond the capacity markets, NECPUC has been working with ISO New England to integrate demand resources into other wholesale markets, such as the reserves and regulation markets, and it has been supportive of ISO New England's recent pilot programs in both of these areas.

As the Commission's competition NOPR reflects, one of the greatest values to full deployment of demand resources is its treatment of the resource in certain ancillary markets, energy markets and the wholesale markets.

NECPUC will continue to work with the regional bodies to integrate demand resources into the ancillary services market. We look forward to realizing the benefits that demand response results in, in the wholesale market, and I think that the conversation this morning got at a lot of those issues, in terms of truly valuing that resource.

As we find ways to deploy increased demand resources, NECPUC is cognizant that somewhat raised concerns regarding the reliance on greater amounts of demand response without appropriate data demonstrating the legitimacy of the resource.

NECPUC understands that ensuring the consistency, accessibility and reliability of demand resources is necessary to support the participation and the expansion of these resources in the wholesale markets, and in the regional system planning process.

To this end, NECPUC recently approved a resolution supporting a regional forum to develop a common demand response measure, and verify and report demand resource savings. Beyond the measurement and verification aspects of this, it's important that this review look at how customer's baselines are developed, to ensure the accuracy and integrity of the demand response event.

New England states are looking forward to working with other Northeastern states to coordinate the research and evaluation of these important resources.

I would like to point out that a lot of what's being done through the regional greenhouse gas initiative, with that larger footprint beyond New England, I think has made New England realize the importance of the collaborations outside of our region.

As we continue on with REGI and the potential increase in funding for state energy efficiency programs and the demand response programs, I think that will play into the REGI footprint.

We'll be taking a look at how these resources are dealt with in the different RTOs that fall under the footprint.

Connecticut and other New England states have been developing ways to integrate their retail programs with ISO New England programs. Variation in rules for wholesale market participation and retail programs is often cited as a barrier to deployment of demand response, and the states have strived to achieve comparable requirements, or at the very least requirements that do not conflict with ISO New England programs.

For example, in Connecticut, the Department has launched a successful distributed generation program that has resulted in increased emergency generation in the state. The program ties our incentives and low interest financing to get that generation on-line with ISO New England programs.

This is particularly important in determining how these demand resources will work in the wholesale markets.

If ISO determines that there's a need for certain telemetry or other metering equipment, the state programs can often help with those increased costs and promote the demand resources.

We've really tried to piggyback our programs off of the ISO New England requirements. Connecticut is actively implementing greater advanced metering capability and additional rate structures to provide enhanced ability to respond to prices with these new rate structures in place, such as critical pricing and the metering equipment to go along with such structures.

We anticipate that customers will have greater ability to participate in these demand response programs, and as I said earlier, I think it's critically important, as the states move towards this, and we're seeing much more emphasis on demand response and energy efficiency and integrated resource planning in state policy goals, that we coordinate our programs with wholesale market programs, so that we can get the synergies that will provide greater deployment of the resource.

I think with regard to other barriers that overplay or work with both the retail jurisdiction and the wholesale jurisdiction, the NARUC-FERC collaborative is undergoing a study right now that has been mentioned. So we look forward to hearing the results from that study.

In summary, I applaud FERC for taking the step to look into this area, and work with the states on these important issues. I appreciate FERC's acknowledging the jurisdictional line between the retail markets and the wholesale markets.

As I said at the beginning of my comments, it's getting harder and harder to differentiate between the two. I'll separate the two out. That's why I think forums like this and a FERC-NARUC forum are important, to get to a point where we can talk these issues through, and work together instead of at cross-purposes. With that, thank you very much.

MR. KATHAN: Thank you very much, Commissioner. I'd also like to recognize that joining us now is Commissioner Moeller. Did you want to say anything before we move on?

COMMISSIONER MOELLER: I'll say it during the course of the meeting.

MR. KATHAN: Our next panelist is Andrew Ott. It says vice president on his plate, but I believe he has been promoted to senior vice president of PJM Interconnection.

MR. OTT: Thank you, good afternoon. I appreciate being here today to talk about long-term barriers to demand response participation in PJM. I did want to spend a moment to two, though, talking about some of the aspects of the PJM market, that we have made great strides in getting comparable access and comparable treatment to demand response in energy, ancillary services and capacity.

Just to briefly dive into the compensation reference this morning, in the ancillary service in capacity markets, there is comparable compensation between generation resources and demand response.

In energy, there is a difference in instead of being paid the full LMP in demand response, demand response is paid LMP minus the retail generation and transmission rate. Frankly, I think the compensation for demand response is too low.

I think the transmission component there is probably some area to discuss pulling that out of there, because to some extent it's really a recovery issue that may be better dealt with somewhere else.

But we are in stakeholder discussions talking about compensation. I won't go through that here, since it's really not the topic of this panel.

I would just reference back to the conversation this morning.

The one aspect, though, that came up from Commissioner Wellinghoff about demand response providing quick response service. We have ancillary service markets. There is regulation and ten-minute synchronized. Demand response has been in our ten minute synchronized. In fact, I have a graph for you to see the growth, and that has been tremendous.

We have the rules in place where they can provide regulations. They haven't yet. There may be a quicker response product, a one minute synchronized or a two minute synchronized, that demand response could provide, and they can be paid a premium for it.

But that's a product definition as opposed to a subsidy. I think there is some fertile ground as wind power continues to grow. I'd like to now -- I have four areas I'd like to talk about.

First is jurisdictional priority. This is a fairly significant issue in PJM. We're a mix of restructured and regulated states.

There's really no established process in the PJM tariff today to allow us to determine whether end users within its jurisdiction in certain customer classes should or should not be able to participate significantly in PJM's wholesale market.

There's ambiguity. It creates ambiguity in the registration processes in the state of Indiana, for instance. Each individual registration has to go through a full hearing at the Indiana Commission in order to come into PJM's market. It's just an immense barrier. We need a much more streamlined approach.

My suggestion is that the Commission should require each RTO to put a provision in its tariff for approval by a state commission. I have principles listed in my written testimony, essentially the notification be clear and unambiguous from the state, and should be based on customer class, not individual registration.

Obviously it should not put it conditionally, saying if you pull in some market with certain features, it will change your features. It should come in, because you can't get jurisdiction of the wholesale market design.

There's a place for unambiguous cooperation and clarification from the state in there.

Another area is information access, basic customer information, contribution losses, location pricing. Currently, service providers have to run around trying to get that data. There's no great choice for them. It depends on state jurisdiction where the data's available.

That needs to be streamlined. It is currently a barrier. We're trying to deal with that within PJM's stakeholder process. Certainly, the Commission can help by encouraging a ban on the states, to try to standardize information access to eliminate that type of barrier in the long term.

Another area is advanced metering, of course. We need the infrastructure in place, the technology in place. Obviously, the FERC-NARUC demand response collaborative is a great space to share and leverage knowledge, if you will. We need to continue to push the deployment of technology.

Then the last area is in the capacity markets and in forward planning. Essentially, we've seen, as illustrated this morning in FCM and in RPM, we've seen a fair amount of demand response on a forward basis getting into capacity markets, which is great.

I think there is some area, though, where we've seen new technology coming out. In PJM's case, we do not yet have energy efficiency recognized in RPM and the forward-capacity market as New England does. So we need to deal with that and make sure that gets in.

But the other is as AMI is deployed, we actually get the true price responsive demand on a retail level. We need to be able to recognize that in the forward-capacity markets and the forward load forecasting as quickly as possible, and not like have a two, three, four year time lag, because that would get rid of some of the benefits.

It would create an institutional barrier. In other words, the state is looking to spend a certain amount of money. If they don't reap the benefit from four years, that's a big deal. So we need to work with the states.

I will be working with the states, to try to make sure that that doesn't become its own barrier as AMI comes out. We need to get in there. With that, I see I'm getting over my time. So I'll wait for questions. Thank you.

MR. KATHAN: Thank you, Andy. Our next panelist is Henry Yoshimura, the Manager of Demand Response at ISO New England. Henry?

MR. YOSHIMURA: Thank you for the opportunity to appear before the Commission. Wholesale markets have proven to be a solution to achieving comparable treatment for demand resources in New England.

Innovative market rules now enable the full range of demand side measures to participate in markets, including both energy efficiency and active real time demand response. New England is now moving beyond the barriers to demand resource participation in the markets to tackle the challenges of making demand resources operate in the market efficiently and reliably.

As you heard earlier today from a number of different folks, we completed our first forward capacity auction in February 2008. We demonstrated the conclusion that we were achieving this comparability at the conclusion of that auction.

Over 2,500 megawatts of demand Resources, you heard from Commissioner George, cleared in that auction of 1,200 megawatts, equivalent to the size of the largest power plant in our system, represented investment in the new demand resources. Almost two times new demand resources than new supply resources cleared in that auction.

Another factor essential to removing barriers and accomplishing comparability for demand resources in the region has been the commitment of stakeholders. Several years ago, stakeholders in New England recognized the benefits of meeting the region's installed capacity requirement, by either increasing supply or reducing demand.

This recognition led to an extensive stakeholder process that designed capacity markets to achieve comparability. Our second forward capacity auction is going to be held in December 2008. There is further evidence that demand resources are no longer facing barriers in the capacity markets.

Another 1,800 megawatts of demand resources have expressed interest in participating in the market in the upcoming auction. As the market continues to attract additional demand response resources, however, new challenges are created.

In the near future, it is conceivable that ISO New England will be operating an electric system with almost ten percent of its operable capacity being active demand response rather than traditional generation.

Studies conducted by the ISO show that the frequency of dispatching demand response increases as generation capacity is displaced by greater amounts of demand response capacity. The frequency of dispatching active demand response in the near future may be orders of magnitude greater than that experienced in New England to date.

If the performance on active demand response diminishes in response to increased dispatch frequency, the ability of our system operators to maintain system reliability also diminishes.

We plan to work very closely with our stakeholders in the near future, to address these challenges. The issues associated with the performance of demand response have ben observed in our demand response reserves pilot program, which permits small, dispersed resources which are less than five megawatts to provide operating reserves.

During the first pilot, we found that small demand response resources yielded statistically significant levels of load relief during our simulated reserve activation events. However, the performances of demand response varied substantially from one event to the other.

The aggregate performance of these assets varied between 30 to 90 percent. These results show that more must be learned to allow us to develop better predictors of how much load relief such resources can provide on a daily basis.

We are presently working with our stakeholders to extend the pilot program. Furthermore, extending the pilot program would give us the opportunity to implement a secure low-cost real time two-way communication infrastructure for small demand resources, to provide ancillary services and to integrate that infrastructure into operations and market systems.

Once we accomplish this, ISO New England will be able to integrate demand response into ancillary service markets. We expect this to happen by June 2010.

Finally, integration of demand resources into the energy market continues to be a substantial challenge. We heard a lot of that this morning. ISO New England has implemented day ahead and real time energy markets to provide efficient and transparent price signals that reflect marginal supply costs.

These price signals can be used to provide time-based retail products that influence economic price response. Unfortunately, the majority of retail demand, as we've heard earlier, and New England purchases electricity pursuant to fixed price products, which give little or no incentive for price response in the energy market.

So to address this market barrier, we have developed and implemented real time price response and day ahead load response programs to encourage price-responsive demand. These programs provide financial incentives for participants to reduce load. These are payments based upon the locational marginal price and we make these payments in response to load reductions and in response to high prices.

These programs are currently set to expire by June 2010. Coincident with delivery of resources in our first forward capacity auction, the ISO is committed to conduct a stakeholder process beginning in October of this year, to address the issue of how to best promote price-responsive demand going forward.

As we've heard from many speakers already, inefficient markets need demand time participation to address market power, to expand the resources available to maintain reliability, and to improve economic efficiency.

ISO New England has come a long way in addressing barriers to entry of demand resources by allowing comparable treatment in the wholesale electricity markets.

Full market integration to make demand resources operate efficiently and reliably, however, will require significant infrastructure improvements to enhance the ability of system operators to rely on demand resources in the capacity and ancillary service markets.

To maintain reliability, system operators need to know how much demand resource capacity is available at any given time, and to see the response to dispatch instructions in real time.

To achieve economic efficiency in the energy market, consumption decisions by retail customers must be based on incentives which reflect actual contemporaneous marginal supply costs.

ISO New England is fully committed to addressing these challenges. Thank you.

MR. KATHAN: Thank you. Our next panelist is Ed Tatum, vice president for RTO Regulatory Affairs at Old Dominion Electric Cooperative. Mr. Tatum.

MR. TATUM: Thanks so much for having us here to speak today. We really appreciate the opportunity. We have prepared remarks. They are in front of you and in the back of the room for folks to go into more detail.

In the brief time we have here, I'll just skim through a few of them. We are a not-for-profit. We're a generation transmission cooperative. Our member service territory is completely inside the PJM footprint, with the expansion in May of 2005.

Subsequently, we've basically been in PJM since day one. I think the experiences we have and the insights developed as a result of that could be helpful to this discussion. We are a member of NREC. We appreciate their support for our presence here today and our comments today.

At Old Dominion, however, the barriers that we're going to be talking about, that I'm going to highlight, are ones we see as a primary barriers. A lack, if you will, of a common vision of what the desired end state for demand response and the wholesale competitive marketplace should indeed be.

I want to say that clearly there's a number of folks who do have a very clear vision of what that end state should be. But our point is we believe we've not come to a consensus vision of that.

We feel that a consensual submission would then allow us to move into an area where we talk about the details of the implementation, and actually get into some of the things that Commissioner George was talking about.

How do we address the intertwining between federal and state jurisdictions, and then actually reveal how we're going to deal with comparability issues, when we think that would provide a good roadmap to move forward.

There's many questions that arise, and we think that would be the way to address it. There's lots of forums to address it. A number of folks have talked about that today. We are very optimistic that PJM's recent implementation of a Steering Committee for Demand Response can help forward this conversation and help us get to such a vision.

The Committee has already begun working on consensus study principles. They provide a link to those and you can actually go out and take a look at them at your leisure. We hope they will enable us to get to a common vision about what we would like to think of as an achievable end state.

We have additionally, as part of this package, a list of initial questions. They're by no means all-inclusive, but we think they might be helpful in framing the vision as to where we want to go. That's Attachment A.

We suggest the Commission continue to work with NARUC and other stakeholders to set the stage for developing this consensus vision, and we wanted to recognize and build on the various efforts already underway. We want to make sure that we have a good, clear definition of the roles and responsibilities.

Again, that's at the wholesale-retail, what can we achieve at each level, and see how each market participant, the RTOs, the CDCs, LSCs, whatever other acronyms you wish to use, fit into this vision.

Secondly, for an electric Cooperative like Old Dominion, wholesale demand response programs are developed by an RTO. They have unintended consequences on us, due to our organizational structure and the consumer focus of our member consumers.

I'd like to remind you that we are a consumer-owned load-serving entity. We have an obligation to provide our members with reliable power at the lowest possible cost.

That's over a long-term view. We've been doing that over many years, engaging in both risk and portfolio management on behalf of our members.

Demand response has long been a part of that portfolio. Nationally, coops on average are controlling about six percent of load to demand response. Some of them are achieving 15, 25 and up to maybe even 50 percent across their various customer classes.

Unintended consequences of RTO-developed programs at the wholesale level could include cost shifting amongst our members, possible misalignment of risk-reward cost-benefit relationships.

Cost shifting is tough for us, as we go back and forth amongst our members. That's a problem. We believe that demand response programs developed in an administratively organized electric markets must recognize the unique role of electric cooperatives, and accommodate our business model in the program design. Just don't forget about us.

Third, we do believe that implementing pricing reforms during periods of scarcity that can facilitate demand response is a bit premature at this time. We are not amenable at this point to discussing elimination of bid caps during the scarcity.

Absent a shared vision, as I talked about earlier, as to where we're going to go for our end state, we feel it would be impossible to know what the proper price is, the penetration of demand response and other factors necessary to know.

If the bid caps should be eliminated, our experience in the Dominion zone -- I've got some statistics in here -- we really haven't seen prices actually approach scarcity, and a quick look at 2007 LMPs indicates about 35 hours where prices were above 300, about six hours where they exceeded $500 per megawatt hour in our neck of the woods.

So we believe we need to ask what are the main response barriers that are keeping us from achieving scarcity naturally. Only after removing those demand response barriers should we consider removing price caps.

We're talking about scarcity, we're talking about resource scarcity. We are very frustrated by our inability for the markets to achieve resource scarcity naturally.

We feel there's already significant barriers to that, with regard to the lack of transmission infrastructure facing many buyers and many sellers. Thank you for your time. I welcome your questions.

MR. KATHAN: Thank you. The next panelist is Tim Roughan, Director of Demand Response of National Grid USA. I believe you have service territories in both New York ISO and the ISO New England.

MR. ROUGHAN: Yes, we do, in four states. In those four states, National Grid acts as the last resort demand response provider, as per state regulation. So even though the markets are competitive market and we've got lots of CSPs working it, we still have to offer the programs in all of the states we serve.

Because of that, our account reps throughout day in and day out, talk about demand response and DSM with their customers, as you know. We've got extensive DSM programs that we've been running for quite some time.

In conjunction with the ISO programs, however, we run targeted programs for distribution issues and constraints, mainly to buy us time, frankly, so the engineering can be done. Through deferral of the distribution issue, we haven't got there yet.

It's possible, we think, but in reality it simply borrows time, because load growth continues to grow very high in parts of New England and parts of New York.

We have a keen interest in keeping the lights on. That's called the rolling blackouts. So we're very keen on that. One of the things I want to bring up today is the opportunity to improve demand response by a significant amount of standardization.

I was involved a number of years back in a large and small generator interconnection procedure. At the time, there was all sorts of different ways folks went through the interconnection procedures in the RTOs and utilities.

If we could standardize the programs throughout the country, as to what the end result is, the vision I think, which Ed just mentioned, is key here. At the end of the day, there's two issues that we're trying to get to.

One is to try to manage the market pricing by providing a different resource that will try to mitigate market power. The other is liability emergency issues. Those are the two basic reasons we have demand response and demand resources.

Ultimately, the program and market designs between the ISOs and between utilities is very different. Baselines we've talked about already. The performance hours are triggers. The NMV, the metering, you name it, it's different between all the different ISOs.

If the end result is the same, there's really no need for all these things to be different. Program manuals from 20 pages in one ISO to 65 at another. The complexity of the programs in the different areas really stymies multinational companies. Barring someone like Lindy Air Systems, they are involved significantly. Wal-Mart is also actively involved in my own markets.

But most regular day-to-day customers really aren't involved, and don't understand it. So make it simpler for them to understand the rules, wherever they are.

They can then easily put a corporate-wide mandate in place, and they'll get the same treatment, whether they are in the Midwest, New England, in New York with PJM and the rules and the policies and the pro forma agreements would be virtually identical.

Prices will change, capacity payments, etcetera. Those would be different by the populations of generators and customers. But the basic standards and things can be the same. We argued about this through the generator interconnection rules, about how it couldn't be done. But eventually we got it done.

Frankly, I can tell you from our own experience that they've been working very, very well in all the areas which we serve and states in our service territory. States have now taken those rules and used them for their own state rules for interconnection.

I think there's a very good chance of this happening with demand response. What's interesting is in the effort to standardize them, for instance, the verification that the NAESB demand response group is doing, particularly IEEE 1547, which worked on generator interconnection rules.

So it fits in very nicely with how we got the generator interconnection procedures in place. Again, a customer-side resource, critical to keeping the lights on. Now we're working on a standard for demand response.

Now we'll have the rules and the base issues that folks have to comply with as a standard, that we can layer on top of those programs and policies, etcetera.

We do have new capacity markets in New England and are very supportive of those markets. It does allow customer-side resources to participate and work off some of the higher costs. It's a fairly quick way that customers can reduce their electric bills, but there are some issues with this.

The performance hours that folks have to work through, are very different. Henry just talked about potentially calling on these resources a lot more frequently, and we have to just be calmly conscious, if that's going to happen.

We have to be able to balance these different types of resources. For example, in New England, you've got to have the same ability for load relief, whether it's winter or summer.

Realistically, the seasonal approach is probably much more valuable and easier for customers to understand and put in place, because, again, they're the ones who are really the end use customers who are going to make these things successful, to simply this process of standardization and allow additional leeway in the capacity markets, to allow -- to provide ways to assist the providers, so they can aggregate these loads properly for customers and make it simpler.

MR. KATHAN: Thank you. Our next panelist is

Sandra Levine, Senior Attorney with the Conservation Law Foundation.

MS. LEVINE: Thank you for the opportunity to be here. I'm Sandra Levine. I work for the Conservation Law Foundation.

It's a regional New England-based environmental advocacy organization. We've been working on electricity issues for well over 20 years, focusing mostly on clean energy and energy efficiency efforts.

Others have noted on this panel, as well as the previous one, the many opportunities there are for demand response in organized markets. As Commissioner Wellinghoff noted, in terms of timing, these are critical issues to be addressing right now.

There is a critical need to deal with global warming impacts, and we're also certainly facing rising fuel and construction costs throughout the country, and there is difficulty throughout the industry, in both siting and permitting new generation and transmission.

As one panelist earlier said, we probably can't build our way out of this problem, so we need some market support alternatives to building our way out.

I want to start by suggesting that the focus of these efforts should not be limited only to demand response. Demand response is certainly a very important piece, and may well be a logical first step.

Many of the same benefits and solutions are available for demand response, and are also available from other demand-side resources, other technologies that reduce consumer consumption. Those should be included, as well.

In terms of barriers to comparable treatment, I think these fall into three general categories. I've addressed these in the written materials, and I'll just mention them here:

One is funding parity, to provide the same funding opportunities for demand-side resources, that there are for other resources.

The second is resource valuation, which the earlier panel addressed in some greater depth, but, obviously, the significant barrier is the organized markets we have, do not value and provide fair compensation for the benefits and services that resources deliver.

A third are planning standards and expertise. In many transmission and energy efforts, as well, demand-resources have typically been seen as square pegs trying to be fit into a round hole.

They're rarely included as actual possible solutions to reliability problems, and, at best, may just be inputs into the forecast.

In terms of specific solutions, I'd like to talk about just a few examples from New England, which is where the Conservation Law Foundation works, that I think highlight some of the pieces of solutions that would be applicable throughout the country.

The first -- and others have mentioned this, as well, is the ISO New England forward capacity market.

It's a good example of how a market that allows demand-side resources to compete on somewhat equal footing with generation, yields some very positive results. The results have previously been mentioned, but the first auction had new demand resources outperforming new supply, by a ratio of about 2:1.

It also nearly doubled the existing demand resources to meet future needs. In terms of cost, the auction resulted in reaching the predetermined floor price.

All of these are benefits, both to society at large, and show that some of the pieces that are in place for the forward capacity market, may be available for other markets, as well.

Some of the factors that led to success in that market, include: First, that the auction was open to a variety of resources; secondly, there was very explicit inclusion of demand resources eligible to meet needs; third, there was a development of a distinct method to allow demand-side resources to be fully integrated as qualified;

and, fourth, there were very clear incentive measurement and verification standards.

This is obviously critical to any effective integration of demand-side resources into markets.

The second examples deal with funding parity and how that can be achieved. This is sort of the equal pay for equal work aspect of markets.

There are two examples I'd like to highlight: The first is the experience in southwest Connecticut where demand resources were deemed to be eligible and actually did deliver to meet needs, to respond to an emergency need in that area.

The second example is an ongoing effort in Vermont, where utilities, regulators, and customers, are together, seeking to improve non-transmission alternatives as eligible for regionwide cost allocation under the New England ISO tariff.

Vermont law strongly supports resource parity, and these efforts to seek funding parity for least-cost solutions, are a means to do that. It's a recognition that just and reasonable rates need to include equal treatment for resources that can meet system needs at least cost.

These are some specific examples that I wanted to provide. I think they can facilitate the transformation that is needed to allow much better integration and comparable treatment for demand resources. Thank you.

MR. KATHAN: Thank you. The final panelist is Robert Pike, Manager of Energy Products at the New York ISO.

MR. PIKE: Thank you, David. I appreciate the opportunity to speak in front of you today.

As indicated, my name is Robert Pike. I'm responsible for program development at NYISO, in areas of improving the efficiency of our energy markets.

I'd like to present to you today, the barriers, from the perspective of the challenges I faced in developing the NYISO programs recently, in particular, with the recent ancillary service provisions.

The first challenge was simply overcoming the knowledge gap. These are the blank stares you face in the room when you say that demand wants to provide regulation and ancillary services.

NYISO has an open governance process, a shared governance process, where we have had in the entire community, program rule changes, and how they will carry forward into our markets. These are the responses you get when you offer these demand-sides: Wants to provide what service? How do they do that?

There's simply a knowledge gap, an education process that needs to occur. This isn't an indication of abilities; it's simply a lack of understanding of what is truly available.

Demand response has evolved considerably in just a few years. The NYISO has had problems in the technology that's available to be deployed, the cost implications this has to the industry and the focus that they have on managing their costs.

So we find that there's a considerable need to pass the capabilities of demand onto a larger community, so they can appreciate what is available within the industry.

I think the question of will demand provide, is a question of the economics of the compensation and the implications for failing to so do. That's a market rule evolution and design.

As part of this education gap, though, I often face the question, what is the impact on reliability? That's an interesting question to face in a market rules discussion, considering that the reliability organizations all evaluated this and adjusted their rules to reflect demand capabilities to provide various services.

What's interesting, though, is that they all have different rules still, which leads to the question of how did we get there on the sound reliability rules?

There is a considerable volume of written reports on the benefits and capabilities of demand response. I don't know what the answer is, but there's a question of who is the expert to sit there and say there is a reasonable reliability assessment done, and everything is progressing appropriately.

Reliability Councils have moved those items forward, but there are still those questions in minds of some in the community, that could be improved.

The other issues is defining the rules. Demand response is not generation. Opening up the programs, is not simply opening up the registration doors and having additional participants in the programs.

It's not a hard challenge; it's simply a challenge of developing the appropriate rules and systems to accommodate a new party into the markets and their participation. They simply need to be vetted and implemented. That can take time to do that.

As an example, I'd say that markets were built with confident knowledge of everything generators needed to participate and we spent the past ten years evolving and customizing those further, so we are still learning what everyone needs in the marketplace in order to fully support their integration.

I feel as though we do ourselves a disservice, when we generalize the term, "demand response." It comes in a lot of different flavors, and understanding how it is all generated and how it is all produced, is important in developing how these programs should function.

As an example, when we were developing our ancillary service program, we had two active participants in our working groups, sharing their experiences and their thoughts of how the program should evolve.

Clearly, we were hoping for more than two parties to be able to participate, once it receives approval, and we've had considerably more join recently in the registration process.

In sharing that, they all do have unique characteristics that we need to understand and appreciate.

Is demand response ready to participate fully in the markets? This isn't a question of capabilities.

There are certainly consumers out there that are still understanding what the power grid needs or what services are to be delivered and how they can partake of that. This is still an evolving market, as they appreciate what they can deliver and we understand how best to incorporate that in.

Finally, as an area to be concerned with, is oversight and participation. As Commissioner Wellinghoff noted at the IRC Demand Response Conference, we need to be vigilant in our oversight of demand response participation, to make sure that the actions of a few, don't taint the overall program successes that we can deliver with these services.

In closing, I'd just like to note that as part of our budget development for 2009, the MISO has recently presented to our market participants, a summary of project candidates for the calendar year 09. This is a list of areas for potential market expansion and evolution.

We presented that in two different forms, to ensure that we had collected the necessary feedback from our participants. And for the purpose of today's discussion, it's important to note that the efforts in demand response, are focused on expanding existing programs, as opposed to the development of new programs.

The list was reviewed and received favorably by our market participant community. Thank you for the opportunity to speak in front of you today.

MR. KATHAN: Thank you, Mr. Pike. Does anyone have any comments or questions?

COMMISSIONER MOELLER: Thanks to all of you for your testimony. I'd like to start with Commissioner George. Given your leadership role in NARUC, that I hope will be there for quite a while, as a Connecticut Commissioner, what does demand response really mean to you?

I'm guessing that the industrial load has taken its hits in Connecticut over the last few decades, and so, in one sense, it may be an evolving concept, but your personal thoughts, speaking from Connecticut, I'd appreciate hearing.

COMMISSIONER GEORGE: Sure. As your question notes, I think there's a traditional definition of demand response, and that is looking at the industrial load that can respond to a certain event, whether it's reliability, whether it's price.

But, I think, as we're evolving and looking at different customer classes and how they can respond, I think it gets us to rate structures and providing certain information to customers at all levels, at all different classes, and then give them the opportunity to respond; whether it's responding to certain prices or whether they're called on.

I think, traditionally, it has been those larger customers that have participated and been called on for reliability events.

As we go forward, I think that's going to be changing, and the question is now, how far can you take it? To what customer classes? And what is necessary to do that, to actually have them respond?

I think the definition is moving. I think certain states -- Connecticut is probably one of the more aggressive states in looking at the different customer classes and their ability to respond.

But I think other states probably are very concerned about pushing the envelope too far to the residential customers, so their definition of demand response is probably more along the lines of the traditional definition, but it is something that's evolving and it's not just a matter of reducing your load, based on the turn of events. It's going to be a combination of reductions in load, based on an event, but also their own individual responses that are done through new technology, new equipment.

COMMISSIONER MOELLER: Thank you. One of the things that makes this entire topic so fascinating, is, as several of the speakers alluded to, we need this, certainly, at a minimum, as a shoulder strategy as our nation moves forward on energy policy over the next eight to ten years.

But there is such an integration between the wholesale and retail markets. Having seen on the ground, what the California ISO is trying to do, the various technologies, at least at the residential level, I'm convinced that we have to have the technology do it for people.

Energy geeks like us, can change out our appliances and our light bulbs, but the average consumer is just not going to probably take it to that level and the technology has to do it for us.

Andy, I guess I have a similar question as to where you see the evolution, now that PJM has tackled the issue, but with a ways to go and where you see it going.

MR. OTT: I think, as I look forward in the evolution, I think we have tackled -- we are seeing demand response providing one of the services we want to purchase as an RTO, which is the ancillary services.

When it comes right down to it, we're purchasing flexibility. What we want, is the flexibility to move either generation or demand response to provide what I'll call grid balance.

I see that if we can articulate, again, as an RTO, in cooperation with the states -- that's what we're looking for, really, is flexibility.

Then I think that if we look into the advanced metering capabilities that we have, if we can get the state rate structures right, there are some valid arguments that say, under certain rate classes, certain embedded cost of service rates, how could they basically sell back to the market at wholesale, because there are some cost issues there?

If we can get the deployment of the AMI, together with the rate structure right, I think that creates for us, the equivalent of a price-responsive demand curve, back to someone like me, who can then do a lot with it in operations.

I see some of these pilot programs that we can marry the two together, just get the technology and the rate structure together. I think we can.

This is not rocket science. Then I, myself, am preparing PJM to be able to be deploy that, to get that price-responsive curve down to the feeder level, the distribution feeder level.

Then I can dispatch. I see that as where we're headed. That's why it's important to me. I need to be able to reflect in my reliability forecasts, that response, as quickly as possible, so that I get the benefit of the energy market and the forward planning.

That's probably the next evolution, I think, today. I think it was called a tornado or hurricane -- I'm not sure -- but a tsunami, there we go.

This morning, they were referring to this as a change. I see it that way. It's going to become a change, but I think the change is going to be that we're going to recognize the flexibility of load, and, in my opinion, in response to price, plain and simple.

That's what's going to save us.

COMMISSIONER MOELLER: Thanks for your recommendations and your testimony, as well. Just a couple more questions, so I don't take too much time.

Mr. Tatum, thanks for your testimony, too, and your thought about the common vision. I like it. I'm just kind of wondering, the vision of demand response in Florida or Southern California, given that their load profile is going to be different than an area with a higher industrial load, people in organized markets, versus those that aren't in organized markets, other than some basics -- and you outlined them -- it is kind of hard to get a common vision, I fear.

Any retort to that?

MR. TATUM: I think, at a minimum, we should go for at least a common vision within the regional market in which we're operating.

As I said earlier, we did a great start recently in PJM. We've got the steering committee; we've got Andy's fairly undivided attention on it, and I think those are two very important components.

I think there are some possibly some fundamental questions that could come across this nation, like, really, what's the proper price of energy? Should we go in for energy prices, just to get at such a level, and where do we lose the benefits of affordable energy that drives our national economy, just as an example?

But I think you could do it on to different levels. It would just require a little forethought.

COMMISSIONER MOELLER: Have you weighed in at all on the debate over whether demand response is a product that can be better delivered through an organized market, or the alternative of a non-organized market?

MR. TATUM: We have opined in our organization, that we have been able to provide what we think is fairly effective demand response outside and before we were participants in an organized market.

But, again, I think that's more of a function of a business structure as an electric coop, than anything else. We're very single-focused, our member consumers are owners. We do not have any question as to where the buck stops.

COMMISSIONER MOELLER: As I think you know, I grew up on coop lines, so I can relate to you.

Finally, Mr. Pike, I just wanted to make sure I heard you right. You said that regional reliability councils are treating demand response differently in their rules. Is that accurate, and, if so, do you have any examples?

MR. PIKE: Yes, that was my statement. An example would be the Reliability First organization that has a limit of 25 percent of the spinning reserve requirement, can be supplied by demand response. In the NPCC arena, that same limitation doesn't exist.

A question I place to the New York stakeholders, is, why do they have to have a limit? What's out there? There is a concern that there should be a limit over there, but you don't think we need one here.

Those are the types of questions I face when there's different rules out there.

COMMISSIONER MOELLER: Thank you for bringing that up and for all the panelists' excellent testimony.

MR. IRWIN: Mr. Roughan, I'd like to ask you this question, in particular: You mentioned a need for standardization to improve demand response and cited examples such as measurement verification and metering requirements that are different between ISOs.

Do you see or is there a role for FERC to help address the need for better measurement verification standards?

MR. ROUGHAN: Again, similar to the generator process, the IEE 1540s did their work and after that, the folks put together the standardized policies and they are working quite well.

The NAESB process is putting together the long-term verification metering. They are going to tackle all that stuff. We're going to have a standard, so the next natural progression is to go ahead and have the standardized policies pro forma agreements, et cetera, et cetera.

The transparency of the programs, is critical to customers, whether they are dealing with the utility running the program, the CSP provider or whoever else it is, they need to understand completely, what they're getting into here.

I have to agree with Henry that I strongly believe that we will be calling on these resources more and more as time goes on. I think it's critical that customers completely understand what's going on out there, so, the more transparent we can make it with standardized programs, from one end of the country to the other, just like the interconnection work, is a critical path which we should follow.

MR. KATHAN: I'd like to follow up on that. As far as standardization, are you saying that you would like to see all the RTOs have the same type of programs or the same type of standards for measurement of verification?

MR. ROUGHAN: The same type of programs. The ultimate goal is to mitigate market power and allow customers to participate in the economic programs, as they choose.

Again, a concern we have, is, if the price program goes away, in New England, for example, when we talk to the customers, the training wheel is demand response. You can learn what to do and how to do it through that program. There's no penalty associated with it.

There's a real process to get customers to participate in demand response. Most of them say no. The first thing is, no, I can't; I don't want to mess up my process; I don't want to make the room too hot.

You really have to do the whole process to get them to agree to do demand response. We've been successful with the amount of demand response we've gotten to date, but we've heard this, but we need huge amounts of this stuff to really counter the climate change issue. It's just that simple.

So I am talking about standardized policies. There's an economic program, there's an emergency program.

Again, the dollars and cents will change, depending on the region and your local costs and all sorts of different things, but, ultimately, consumer service and capacity.

MR. KATHAN: Henry?

MR. YOSHIMURA: Thank you. Just to mention a couple of things, I agree with him that standardization of certain things is important.

Measurement verification, some of the communication telemetry models, these are two things that actually the IRC the ISO/RTO Council, are working on currently.

We're doing this collaboratively. The ten RTOs in North America are working together to try to come up with more standardized ways of communicating with demand response assets and more standardized ways of determining the savings from a demand response participant.

We're looking at the baseline right now. There's a lot of work involved, because we all start from different places. We're all products of a stakeholder process.

Localized history, there's a lot of it, what I'll call baggage that we carry into the future, based upon where we've been. Programs that we have run in the past, and tried to keep things from moving too radically, but moving forward at the same time, that's part of the reason why things are different.

The other is that our market designs are different, because demand response -- I'll speak for myself -- ISO New England tends to look at how does demand response participate in this market? So, let's say it's the energy market, the capacity market, or the ancillary service market, I think the other RTOs' thought is -- they can say for themselves -- probably look at things the same way.

They have a market that they're using to fulfill a need, and a design that goes along with that market. It could have evolved, again, from a different history, a different starting point, a different set of stakeholders, so it's a challenge to try to get things to be more standardized.

I fully appreciate that. I work with customers that have a national presence, like WalMart, Home Depot, those sorts of customers that participate in demand response programs.

They have to learn 50 ways of doing the same thing, perhaps, and it's an issue. We as RTOs, believe that we need to tackle some of these things, but it's going to be a long way to go, because, again, we have different market designs and we have different histories and different stakeholders.

MR. ROUGHAN: Just a comment. I agree this won't be a simple task. We have the same problem within the connection, of 50 different rules. The whole point was to have a common standard and it will take six, seven, eight years to take a large set of rules through the implementation.

There's no question it was hard, but I would suggest that all the same issues that existed for that, exist today for demand response.

We got through that in the interconnection work.

MR. KATHAN: Thank you.

MR. KELLY: I was listening with one ear to the panel to see if I got an answer to the question of what FERC should do to address additional barriers. I'm going to assume you're all aware of our current proposed rule dealing with scarcity pricing and aggregation of customer ancillary services and deviations.

I'm sure you're aware that Congress has given us several assignments: Annual demand response reports, national assessments, national action plan.

We're also engaging in a collaborative with NARUC. Is there more we should do to address barriers in wholesale markets?

I was listening and didn't hear a clear answer. Some of the speakers were saying what RTOs should do, what their stakeholders should do, what the states should do.

With the states, arguably, some of the suggestions, FERC could act on, such as helping to fill the knowledge gap or funding parity or standardization, although, arguably, you might say, no, no, we didn't mean FERC should do that; that's a NAESB job; that's a NERC job; that's an RTO job.

Does anyone have something that you think FERC should do to address barriers to demand response reaching comparability with generation, over and beyond the things that we're already engaged in?

I'm leaving that somewhat open-ended. I'm not really asking for every panelist to answer, but if you have a positive answer, yes, I'd like to hear it. Mr. Tatum?

MR. TATUM: Thank you much for that. It built on the initial recommendation of trying to facilitate as common a vision as we can.

I think the ongoing initiatives, especially the collaborative with NARUC, provides and excellent vehicle to build on, and I ask that you all consider adding some direction to it, to just try to put some more flesh on really what we might wish to see as an end state.

Again, I gave the example of what is the proper price for energy? Where does J&R begin and end?

Should demand response be paid to reduce loads? Sometimes, should demand resources be paid? If they are providing an energy service, more than likely, they should. Where do the benefits lie?

I we have to do incentives to jump-start, or, as we said earlier, prime the pump, is there s sunset date? How long should that last? Is there a penetration we may be looking for? Is there a certain optimal amount of demand response? Is all demand response good?

These are the types of questions, and, again, these are just initial questions. I'm sure folks with a lot of imagination, can come up with many more.

I think they will provide a basis for, as common, if you will -- and I appreciate Commissioner Moeller's comment -- as common as we can, a vision, so we can really sort of roll up our sleeves and get down to the implementation and solutions.

MR. KELLY: Thank you.

MR. KATHAN: Andy?

MR. OTT: Thank you. I have a few recommendations. One was in my testimony, on the issue of the jurisdictional clarity and how the Commission could have required the RTOs to include in our tariff, a provision to allow for a state to, I would say, deny or not approve a certain customer class to participate in the RTO market, maybe because of a rate issue where you have a cost-based or a rate that already includes demand response or a synthetic cost rate or something.

That would create an immense amount of clarity within the registration process. I think it would clean out the registration process and reduce a barrier that exists today. At least in PJM, I think we have that ambiguity and it's something that is actionable within your jurisdiction, I think, to say that the RTOs have o recognize and have a space for that kind of thing.

At least I believe it's something you all could do.

MR. KELLY: Could you elaborate on it a bit? The first time I heard you say it, it almost sounded like we might be doing something that the states should be doing, and I want to make sure I understand it.

MR. OTT: Right now, there's an ambiguous situation that exists. In the State of Indiana, for example, if a customer comes to us and wants to register either to provide capacity -- in RPM, for instance, right now, we feel in our tariff, that it's required and the customer feels they have the ability to do that.

There's a requirement, though, within the State of Indiana, that says that customer has to go before the Indiana Commission and get approval before it can participate in our market.

So, the customer says, well, I can do this, and they just sign up and you have to say yes, but then the state says, well, I didn't say yes.

The point is, for the state to go through each individual registration like that, is an immense barrier. So, if there could be a generic, okay, the state could say either, yes, you could have emergency demand response, or, no, you can't, by customer class or whatever, which would just clarify everything, so that it wouldn't be going back and forth between jurisdictions and having customers spend the money doing that.

And there's other reasons, you know, like the economic programs. If a state has a certain rate class that they don't want in our economic program, if there were a provision in our tariff to allow us to recognize that, then that registration process, it could just have, what's the rate program, period, so it's very clean or clearer than it is today.

A margin of three months and whether it is risen, I think, would be helpful. I think it's the same thing with information.

There's another information access issue, again, that just requiring RTOs to have certain basic customer information to be held, for instance, within the RTO, as opposed to distributed, maybe, again, would clean up the registration process and put forth, if you will, the responsibility on us, for instance, or perhaps at least give us the opportunity.

Another thing you've done for us recently --

MR. KELLY: Before you leave that, I want to make sure I understand it. In your prepared remarks, you said something like you thought this was a state barrier, that the states need to standardize access to information. It's not clear to me, what the FERC action there is.

MR. OTT: Again, if you encouraged or told us you feel it's the responsibility of the RTO to have that data, then maybe we could work with the states and work through the issues. Most of the issues are customer confidentiality, so maybe we could work through some of those issues.

And, again, it's more clarity of roles that I think you could be helpful with. Again, I'm not trying to create a jurisdictional issue, as much as these are the specific issues that are creating fairly significant churn, if you will, to registration.

If we could lower the cost of registration, you know, it's an immense savings, and people can actually do business, "people" being service providers. It would lower the cost of their overhead, if you will, and perhaps make it easier for them to aggregate customers.

Now, I think that another thing you've done for us recently, is, at least I feel you've unambiguously told us as PJM, you need to accommodate energy efficiency in your forward capacity market.

So, when I go then to stakeholders and say, okay, we have to find a way to do this, we at least have something to shoot for. That kind of clarity, where certain things need to happen, like, do you need to put ancillary -- demand response in ancillary services, as well?

In fact, we already have it, but, saying that unambiguously, that it needs to happen -- you don't have to tell us how to do it, necessarily, but the fact that it needs to happen, I think, is something you can do.

For instance, with energy efficiency that may have been covered in a NOPR -- I'm not sure that specifically was.

But the other thing was price-responsive demand curves, like we were talking about before. If we do have AMI developed, if we do have critical pricing retail rates developed, then you may, in fact, see a lot of price-responsive demand.

Signalling to the RTOs that we need to accommodate that in our forward planning process, using our forward capacity markets, needs to be there, because, if it's not there, at least in relatively quick mode -- part of the benefit of that investment in technology, will disappear.

So that kind of thing, you can do.

MR. KELLY: Commissioner George?

COMMISSIONER GEORGE: Just to respond to some of Andy's comments, I think he clarified, but, obviously, I would just caution the FERC to take the steps.

We've seen this happen; we've had litigation on this, where an RTO tariff is used to sort of bootstrap your way into some of the issues that are traditionally reserved to the states and legally reserved to the states.

So, some of the issues that Andy brought up with regard to standardizing information-sharing, clarifying the rules for which customer classes can participate, I think, are excellent issues that need to be worked out, but it's more something that I think should be worked on in the setting of the collaboration.

Issues are identified and the states have an opportunity to respond, and one of the things that my testimony touched on, and what I've tried to say in the collaborative, is the states, especially the state with organized markets, really should, in developing their programs, try to work in conjunction with the wholesale markets, so that you aren't working at cross purposes.

So, some of Andy's examples are exactly that, where you have state systems in place, that make sense, but maybe you just need to tweak them a little bit to make it easier for customers to participate in the wholesale markets.

MR. KELLY: Thank you.

MR. TATUM: I just wanted to jump in. I agree with just about everything Andy said as far as things the Commission could do to help the RTO. As you help the RTO, I would ask that we be mindful of what, indeed, is achievable, given current penetration of technology and current evolution.

I think there are opportunities to evolve demand response, grabbing the low-hanging fruit first. Are we really getting the most out of our large industrials for demand response? What additional things can we do?

Are we getting what we really need out of commercial and industrial customers? For that next echelon, what do we need to get more out that C&I? Do we need education? Do we need facilitation at the state level? How will the states interact back and forth?

Will we be able to modify retail rate designs, such that folks are actually seeing that wholesale price back and forth? Again, I don't disagree with what Andy was saying, but I have a sense of a timing component of when it should be done, based on what's achievable, given the current state. Thank you.

MR. KELLY: Just to follow up with Mr. Tatum, it seems to me that as PJM works with, say, the states, on information access, there are going to be some coops, not state regulated, that would need to be brought into the fold for any kind of uniformity.

What would you think would be the best way of working on that?

MR. TATUM: Generally, you should bring us in, kicking and screaming.

(Laughter.)

MR. TATUM: Clearly, there's a role for the coops in there. Again, we want to be part of the process.

One of the things I did mention earlier with regard to coops being different, is, we've experienced it in the PJM program where we've said, wow, this isn't working for us, how can we make it work?

We've had some very good discussions. There were a couple of ah-hah moments there, oh, well, you are, indeed different, so, to make it work for you, we need to do these things, we need to be thoughtful about it.

We're happy to engage in that. It's just that we try to be as active as we can in the PJM stakeholder process, so I would guess that we would prefer to continue to participate in that way, if that works for you, Andy.

MR. KATHAN: Okay. I have a specific question for Mr. Pike. You brought up an issue that you said was a knowledge gap, and particularly on the customer side. I'm going to do a similar type of way of asking a question that Kevin was, which is, is that an issue that the Commission needs to be involved with?

Is there a role for the Commission in order to help get over that knowledge gap?

MR. PIKE: There's a role for all us in conveying what's available in the marketplace, or what could be developed in the marketplace. I think we could all help educate those, whether it's open forums or discussions or industry leading representatives to help formulate those discussions.

I think one area that was in that knowledge gap, that I struggled with, was the question of reliability aspects. If the Reliability Councils have come up with a variety of different rules -- and I'll stamp them as appropriate reliability criteria -- how do you reconcile that, and were those distinctions planned?

I'm sure there could be very good and different rationales for them all, but without them on the table, it's difficult to argue why one is different than the other.

That may be an opportunity to help reconcile those differences or explain those differences, so that we can all step back and appreciate why they are what they are.

MR. KATHAN: You're saying that Reliability Councils should be developing consistent approaches, or that there needs to be a NERC role? What are you suggesting?

MR. PIKE: I don't know that they need to be consistent, but I don't know the rationale for all of the differences or who is the right resource to be able to stamp the appropriateness of the different aspects of demand providing these reliability services.

Is it appropriate and acceptable? We can just take it on its face, that they are different, that they have been adequately vetted within all the different reliability regimes and they are what they are, for the reasons that the groups have decided.

That's more my question, of just being able to justify the differences between them, to be able to understand and explain why what we have, is appropriate, or what needs to be changed within the provisions, to make them appropriate.

MR. AMERKHAIL: My name is Rahim Amerkhail. You mentioned, Mr. Pike, the knowledge gap, and we were just discussing it.

But part of what you said, was that we do ourselves a disservice by talking about demand response as though it's kind of a uniform product. You said something like that.

That's something I've been thinking about. Mr. Yoshimura also mentioned the idea that the more frequently you rely on a particular demand response asset, the more likely it is at some point, for him to decide, do I make steel or am I a demand response provider?

I think that's a legitimate concern, but I think there are two broad categories of demand response providers now: There's the type -- and correct me if I'm wrong on this -- there's the type that basically just turns something off, maybe an industrial process. It may be an aggregator that has signed up a whole bunch of retail customers to cycle air conditioners or whatever.

And in that case, you know, it seems pretty obvious that there's a tradeoff between doing what you do, or providing demand response, but I'm under the impression that there is kind of a new group that does this in a more scientific way, if you will, go into a chain of big box stores, they'll study how they operate, why they operate a certain way.

Could it be changed with adversely impacting the operation? For example, instead of cutting off lights in this room, they might install dim-able lights and study how much they could dim it over what period of time, so that we wouldn't even notice it had happened, sitting in this room.

They might also put in variable speed drives on a refrigeration plant and study how much could they vary the temperature without impacting whatever is being refrigerated.

The bottom line is that they could provide demand response, sustainably, because there's no tradeoff.

I'm wondering about this concept, how much is it being studied, taken into account in, like, your market processes. It seems like some types of providers, the more sustainable process might be better suited to providing some ancillary services.

It might be better suited to provide a capacity over longer periods of time than what you're used to, what type of work has been done, and if there isn't enough, who should do it?

MR. PIKE: I don't think there's enough work in that area to truly understand what characteristics are in the marketplace and what level of responsiveness they could be delivered now or in the future, with all the automation.

I think you're absolutely correct that a significant technology deployment occurring in the field, that this is all being automated through central control systems, connecting into EMS systems and commercial energy management systems, that they are connecting into industrial processes, and, in some cases, they are fully automating across diverse sets of customers.

So I know I've got a customer that can get me 20 minutes, so he goes first, because he goes really fast. I've got another customer that can give me a couple of hours, so in 20 minutes, I'm going to swing over and actually pull from this industrial customer or bring the commercial air conditioning back online.

I think what I see a lot of, is what are the characteristics of the resources that are capable of providing this? Are they really good for 15 minutes? Give them a half an hour to recharge and they are back and available, or are if it's an industrial process, I give you eight-hour chunks and that's all that I can provide for you.

So, it's more of the characteristics of what the resources are able to do to respond to a request from an ISO, for whatever reason, whether it's reliability or price. I think those two need two different types of services, at least two different types services.

New York has reliability-based programs, where we're looking at day-ahead, trying to address whether we've got system conditions that warrant activating these programs. We give 21 hours notice and a guaranteed four-hour haul on these programs. That's great.

But we don't always forecast the emergencies, 21 hours in advance. Sometimes they happen much more unexpectedly, and being able to then say, okay, what's another set of resources that can give us notice in 30 minutes and give us 60 minutes activation?

I think they all have their place in the market, but I certainly don't have a full appreciation of what the market could offer right now.

MR. ROUGHAN: Through the energy efficiency programs we've been running for 20 years in the national grid, we're migrating to the combination of energy efficiency and demand response projects, because, ultimately, what we're trying to get to customers, is, initially modifications for EMS that will shed load for just those few hours needed.

Eventually, customers learn to live with that, and now their base usage drops. So it's a constant iteration for customers. It's not that you go in one time and you tweak something and you walk away forever; it's a constant iteration to help customers in what Robert said earlier about customer education.

You can't think that's not a lot of work. It's a ton of work, because it's a constant iteration.

You'll do some work with a customer and they'll get by, and, finally, they'll just live with it, to have a lower bill all the time. Then you've got to work on more projects with them and they'll do more and more over time.

It is something -- I serve on a lot of this automated DR that was talked about by Dan on the prior panel. In California, we're starting to see a lot of that. I know that some of the CSPs are doing a lot of automated DR, which, again, will migrate.

That's the setting now, and then you'll do more as you learn more about the process.

MR. YOSHIMURA: If I may, what makes this topic difficult to address, is that demand resources -- and, by the way, I subscribe to the definition that Paul Peterson offered earlier, that demand resources are a bunch of things that happen behind the customer meter, which change the demand in some fashion.

What makes this difficult, is the fact that demand resources are as diverse as the demand it comes from, so then we're left in a position to try to figure out, how do we capture the characteristics of the demand resource to serve a market need?

What that leads us to, is having to identify the major characteristics of the demand that could enable it to participate in a market or not.

Let me just offer some ways that a system operator looks at a demand resource. A system operator obviously has to balance energy, the demand and supply, in real time, all the time.

Also, he has the responsibility for planning into the future, so that down the road, we have adequate capacity to serve customers' need.

Now we're talking about different markets' capacity, energy, and ancillary services. How does demand serve that?

There are different demand resources. Some are passive, like, you change out the lighting system, you change the motor, you put in energy-efficient air conditioners. It's not a dispatchable resource -- completely not dispatchable, but it could help your capacity situation.

It reduces the load, and, hopefully, it reduces the load at the right times, so, therefore, it does help. Therefore, that was our reasoning for incorporating energy efficiency into the capacity market.

But it has a very different operational characteristic than a real-time demand resource. Someone has to give it the signal. There will be a dispatch instruction to tell them when to interrupt and when to restore the load.

Both of those resources, the way we look at it, both of those resources can contribute to offsetting the need for generation capacity and transmission capacity, for that matter.

Therefore, they both should participate in the market, so the problem is that they have very different operational characteristics, like passive versus active.

So how do you incorporate them into the same capacity market? It turns out, the way we did it -- and maybe there's other ways of doing it, but this is the way we did it -- we have to figure out, okay, what is the need for the system, look at how do these resources perform, and come up with a rule that marries.

So, an on-peak energy resource, something that reduces load across -- on peak hours, you have to define the on-peak hours and figure out a method to determine what its capacity value is. A real-time demand response resource, is not reducing load all the time; it's going to strategically do that.

Then you have to have a different set of hours, but it turns out that you can do this. We tried to do it and I think we did it.

You define different sets of performance hours that, altogether, contribute to reducing your -- basically avoiding generation capacity, and that means if you can do that, all these megawatts are equivalent, and, therefore, can participate in the same market on a per-megawatts basis.

So it's a recognition of passive versus active, trying to come up with the right rules that marry those concepts to a need in a new market.

MR. AMERKHAIL: That's work you've already done, and you don't see a need for some sort of uniform work that cuts across the nation?

MR. YOSHIMURA: I'll just speak for New England. We have the rules in place. We cleared an auction and resources now have capacity obligations, demand- and supply-side resources.

We feel it was a successful auction. The challenge that we have going forward, is, these performance characteristics that I've talked about, in one sense, are not proven; in other words, we suspect that resources can provide load reductions at the right times, but we are also seeing that we haven't had resources to do that before.

So, that puts us in an interesting position where we're going to go off and use these as capacity resources to meet a long-term resource adequacy need, without data confirming that some of these resources can actually provide load reductions in a certain set of hours, as opposed to what we're currently doing.

There's an uncertainty there. We're taking a calculated risk. We feel that they can respond, but it's a risk.

So that's something that I think New England is uniquely situated to have to deal with, because we, as a region, we're in a position to say, yes, we're going to use demand-side resources to meet a capacity need. We made that decision and we're going to make it work.

MS. WHITE: A followup to what Rahim just said, in terms of you're only speaking for New England, but it goes back to Ken's question. Is there something FERC can do in this area, to make sure that passive demand response or energy efficiency gets adequate signals in other parts of the country, in order to participate in these markets?

MR. OTT: Again, I think you can and have, at least from PJM's perspective, told us, find a way to get energy efficiency in forward capacity markets, that would make sense.

So I think you can give those types of instructions, whether it be ancillary services, forward capacity markets. How it's done, I think perhaps could be regional. I don't know if it is or not, but the unambiguous statement that forward capacity markets need to recognize energy efficiency, is pretty easy to understand.

MR. KATHAN: I have one final question, which is to Sandra. Following up with what we've been talking about, given you were part of that process, do you have any lessons that you've learned from that, that you would want to pass on, also, to the national level, or possibly to other regions like PJM?

MS. LEVINE: I think a few of the lessons I mentioned earlier, to recognize that there's a distinct method, as Henry talked about, that recognizes the ability of the demand resources and the services they actually can provide, and marry that to your system.

That clearly identifies what the need is. If you don't identify the need for something that only a transmission project or only a generator could meet, I think the other piece of that, as far as lessons for other parts of the country to build on that, is to make sure that whatever markets you have, that they are open to a wide variety of resources to participate, and that they have the same opportunities, both for funding and participation, to meet the system's needs.

MR. KATHAN: Okay, thank you, thank you, panel. With that, we'll move into a break. We'll be back at 3:00, so ten minutes.

(Recess.)

MR. KATHAN: Let's get started wit the next panel. If you're in the middle of a conversation, would you please take it outside? Could all panelists please come to the table? Let's get started on Panel III.

This is the second panel examining barriers to comparable treatment and solutions to eliminate potential barriers. The focus of this will primarily be California ISO, the Midwest ISO and SPP regions.

Our first panelist is Dennis Derricks, Director of Electric Regulatory Policy at the Integrys Energy Group, Incorporated. Dennis?

MR. DERRICKS: Thank you. I appreciate the opportunity to speak to you today on demand response. It's something that's viewed as very important by our company, not only for the reasons that have been identified previously here today, but it's also a very important tool for us to actually provide value to our customers.

That's becoming increasingly important, as costs are increasing. We also believe it's important to have DR reflect the actual costs and not provide subsidies. We don't believe that's sustainable in the long term, and with raising prices, that will also raise prices for others customers, non-participating customers.

I think that was something that was described very well today, as well.

We are a little bit different. First, we're in the Midwest ISO. We do have 100-percent EMR deployed within our service territory, and we do have a significant amount of demand response programs already in place.

Those start with our legacy interruptible programs and direct load control programs, and we've been moving two critical pricing programs, not only for large industrial customers, but last summer, we introduced that to our residential customers and will continue to expand that and look forward to expanding demand response programs to more and more customers.

Currently, demand response reflects about 15 percent of our load. We actually use that demand response program to utilize the demand market-sensitive bids in the day-ahead market within the Midwest ISO. That works very well.

There are two things that I want to try to get across today and some are echoing some of the positives that have come out of the forward capacity markets that are in other RTOs that are not in the Midwest ISO at this point in time, and also discuss, maybe not so much a barrier, but maybe a concern of mine with respect to the lack of an understanding of what failure to interrupt load at emergency times, actually is in the Midwest ISO at this point in time.

To do that, I'd really like to give you some idea about -- we have our legacy interruptible load program. Customers get a monthly credit for the right to be interrupted. It basically reflects the avoided costs of the CT.

There's two types of interruption: There's an economic interruption, so when the price exceeds the cost of a CT, significantly, they will get a day-ahead interruption. Last year, they received over $200 of interruption and at that point in time, they are actually exposed to the real-time LMP market.

Reliability: What the Midwest ISO would call an emergency interruption, those customers are required to get off or be subject to a significant penalty.

The last reliability interruption was in 2006. We also have critical peak pricing programs, which are different. They apply to different customers, and, up to $300, a customer can priced at 45 cents a kilowatt hour.

The other hours, they actually receive a discount compared to the standard rate. They are very different programs.

They appeal to different types of customers, and they really have different values in the marketplace. Both are needed, just like we have different generation types of units -- coal, baseload, and peaking.

I think there's a need for different types of programs, going forward, but we need to be able to provide an adequate way of actually evaluating those programs and what they provide in the market.

We believe a forward capacity market in the Midwest ISO, would be a great step forward for that, would actually allow us to reflect that capacity credit in our interruptible programs and really be a nice efficient way of determining the capacity value, in an efficient and transparent way.

Lastly, the thing I talked about a little bit, is the fact that our traditional legacy interruptible program, does have an interruptible penalty for noncompliance. It's very significant and very well known by our customers.

Because of that, those customers, when they get that notification for an emergency interruption, they do interrupt.

As we move forward to more reflecting the actual Midwest ISO or the wholesale prices into our retail tariff, we would think that we would actually be moving toward getting rid of that retail legacy penalty and reflecting more of the actual wholesale penalty.

At this point in time, we're not exactly certain, what actual financial consequences would be resulting from failure to interrupt. We just don't think -- that's not a way for us to move forward with demand response.

There is already the uncertainty with respect to demand response actually being there when called, and we believe there needs to be some more work done in that area, as well as the verification and those types of things.

That concludes my remarks.

MR. KATHAN: Thank you. Our next panelist is DeWayne Todd, Power Manager at Alcoa.

MR. TODD: Thank you very much. I appreciate the opportunity to be able to speak with you this afternoon, and Alcoa appreciates the opportunity to talk a little bit about the aluminum business and how we are very interested in demand response processes and programs throughout the U.S.

Alcoa has over 2500 megawatts of load in the U.S., distributed across various RTOs. Warrick Operations, which is where I'm based, has about 550 megawatts of load as an aluminum smelter.

It's a fully integrated facility. It has its own generation, as well as its own 450 megawatts of smelting load.

Smelting load is a very flat load, in and of itself. We also have rolling facilities attached to that. We have been very active in demand response since the plant came into inception.

Reliability is very critical to the operation of the plant. I've tried to outline a lot of those issues inside of the written remarks, but I would like to highlight a couple of things.

In particular, we have participated in traditional demand response, as long as the plant has been there. Ten years ago, that entailed two or three events in a year, where we would interrupt our smelting production, typically due to reliability issues on the grid.

With the market in the Midwest ISO that came into play in 2005, we began to see a lot of opportunities to help mitigate or externally purchase power costs. On a normal day, we cover our loads with our generation, but if we're short of generation, we need to purchase from the external grid and purchase about ten percent of our load on an annual basis.

As we began to interact as a price-responsive demand response provider, we saw a lot of opportunities where, basically, the value of the power became more than the value of the aluminum. In fact, in 2007, we had over 1800 events that we documented, where we would either back off our generation, where we'd become a stronger load on the

MISO system because of the price of power was low or the price of power was is in the negative price range, or where the value of the aluminum was less than the value of electricity, so we would back down our load, in itself, or either become a net exporter, or reduce our purchased power off of the grid.

Needless to say, it's been a complete transformation in terms of how our business operates day-to-day. We watch the five-minute price signal. We are very active in how we respond to that.

It's a 24-hour-a-day, seven-days-a-week very active activity. We also monitored what we see as the next big step change. That is ancillary services.

We've worked very closely with MISO to help facilitate getting ready to participate in that process. In particular, we're looking to provide regulation off of our smelting load. We're not doing it off generation; we're taking our smelting process, we're making the aluminum, and we will allow the Midwest ISO to directly control our load and our production levels.

We're basically -- the aluminum production process is directly proportional to the electricity that we put into it. We have invested what we feel is significant capital into that process, to allow us to participate, in excess of three-quarters of a million dollars.

We've invested resources in terms of people, and we have been successful in participating in multiple tests so far. As the Midwest ISO is preparing for implementation of ancillary services markets in September, we have actively participated in their parallel operations and been successful in providing regulation.

So, again, we have our load directly being controlled from Midwest ISO.

There have been a number of barriers that we have needed to overcome, in order to get ready to participate. We feel like we have a lot of resources to put into that, because there's a lot of opportunity at the plant. We think that we can potentially provide up to 180 megawatts into that grid.

So we know the potential is there, however, those barriers that I've kind of outlined in our written remarks, would serve as obstacles to, say, our other locations participating in those markets, because the potential is not as big, so the investment of resources, capital, and those things that we do not believe are requirements in order to participate, become significant barriers.

That includes factors around how the load is directly modeled like a generator, how we've had to create multiple-node telemetry and metering requirements, as well as some of the forecasting and staffing issues that have been created, in order for us to participate in them.

I look forward to any questions and discussing this more at length.

MR. KATHAN: Thank you, Mr. Todd. Our next panelist is Jason Salmi Klotz, Senior Analyst at the California PUC.

MR. KLOTZ: Thank you, Mr. Kathan. I submitted some slides to the record and you can follow along during my presentation, thank you.

I'd like to thank the FERC for having me here. My name is Jason Salmi Klotz. I am a Senior Analyst at the California Public Utilities Commission.

California views demand response as a top priority, at the top of order along with energy efficiency. Because California's new wholesale market is not fully mature, the CPUC views the barriers to comparable treatment of demand response in the wholesale market, to be both within the market, i.e. within our control and jurisdiction, and outside their control, i.e. state jurisdiction.

My presentation is centered on the issues present within California. I'll quickly overview four areas in which the CPUC has identified barriers, and some of the ares that the Commission is working on to implement of has implemented.

Currently, the ISO does not have a forward energy market. We see this as a barrier.

Currently, the requirements of the CAISO's participating load definition, have been seen as difficult by a number of our participants.

The CPUC and the CEC and the CAISO have worked with our investor-owned utilities and other interested parties, to create a demand response to our proposal, which makes possible, comparable treatment in all of CAISO's markets.

CAISO's proposal includes a mechanism for our smart meter, one-hour-interval customers to participate in the market.

The CAISO and the CEC have refined the requirements for participating load, and added an additional day-ahead DR option called non-participating load.

Following the energy crisis in California, the California Legislature passed an Assembly Bill which has frozen residential rates at 2001 levels.

This has been a significant barrier to dynamic residential rates or dynamic pricing, especially as we try to take advantage of the statewide smart meter rollout.

As smart meters are installed in homes throughout California, which will be completed by 2012, all utilities will implement a peak time rebate tariff for all residential customers. It's kind of a dynamic rate without harm.

We will shift them slowly over to a more dynamic rate afterwards.

Dynamic pricing for large customers has also been difficult. PG&E currently has about 25 megawatts of critical peak pricing, while SCE only has one. The IOUs will be implementing a default CPP and a choice of real-time pricing, by 2010, for large customers.

Currently, neither the CPUC nor the CAISO or the IOUs know fully, the load draw brought about by demand response. This makes forecasting difficult for long-term planning, resource adequacy, and the CAISO's day-to-day operations planning and forecasting.

The CPUC has worked with the IOUs, Summit Blue Consulting, and other interested parties, to trade load impact protocols for measurement, planning, and settlement purposes.

The Phase I protocol settled on the needs of the IOUs and the CPUC. Phase III of our rulemaking, 07041, will center on collaboration with the CAISO in creating load impact protocols for CAISO's day-to-day needs.

This summer, the CPUC will study the effects of the morning adjustment factor on two hard demand response programs run by third-party aggregators. The Commission is also funding and requesting greater implementation of auto-DR technology, which has helped affirm DR resources and make it dispatchable by the CAISO, the IOUs, or a third party aggregator.

Currently, all DR in California, is administered by our three IOUs. This has created a disconnect with the CAISO, for a number of reasons, including dispatch triggering mechanisms, incentive levels, transparency, location of the DR resource, and simply informing the CAISO when and how much DR is being triggered.

The CAISO is working to incorporate DR through a step-by-step process, as outlined in their DR straw proposal for MRTU Release 1 and post-Release 1.1.a.

The CPUC has requested the IOUs submit their 2009 and 2011 program proposals, due on June 1, 2008. Price-responsive DR, which will be properly in line with the wholesale market operations, will be ready for inclusion in CAISO's markets by the time MRTU post-Release 1.1.a goes live.

The CPUC is currently developing cost-effectiveness protocols exclusively for demand response. We expect these protocols to inform us on the costs and benefits of DR, including previously undetermined externalities.

These should go a long way to help us and help inform the CAISO and the CPUC on the proper pricing structure and incentive mechanisms for different DR programs and services.

On the last slide here, are a number of different CPUC DR policy highlights. Again, we placed DR at the top of the loading order and require our IOUs to meet five percent of their peak demand with price-responsive DR, roughly 2500 megawatts. Currently, we allow third-party aggregators to contract with our IOUs.

Lastly, I would emphasize that the CPUC does not view DR as simply a peaking resource. We incorporate permanent load-shifting and storage as part of our DR and we expect that DR can help integrate intermittent renewable resources and have directed the IOUs to propose pilot programs to that end.

We also believe that small DR resources, if aggregated, can supply ancillary services, and have, again, requested pilot programs from or IOUs to that effect. Thank you.

MR. KATHAN: Thank you. Our next panelist is Michael Robinson, Senior Manager of Market design at the Midwest ISO.

MR. ROBINSON: Thank you. The Midwest ISO appreciates the opportunity to provide comments here on demand response and barriers to participation in our markets.

To consider the barriers, we really have to look at where we are today in terms of offering demand response in our different markets. To do that, we really go back to the foundational principles.

At the Midwest ISO, our foundational principles are that if we're going to set up a market, it works best when we have vigorous participation by both buyers, i.e. demand response, and sellers. Furthermore, markets work best when you have voluntary participation choice by these buyers and sellers.

So what we've tried to do in developing our products and services, is to create an open market platform where participants can voluntarily choose to participate on an equal, level playing field.

So I have prepared remarks here today, and I'm not going to go through all of these, but what we tried to do, we have an open, level playing field.

Are we setting up the correct prices that were mentioned this morning? Do participants get to see those prices? Can they react to those prices?

To do that, I'm not going to talk about demand response markets like some talked about today. I'm not going to talk about demand response programs.

I think the best way to look at this, is, what are the different products and services that the RTO is providing?

I see it as five different categories, and, within each category, I ask myself, is there an open, level playing field for demand response to participate?

Those five categories are: Spot markets, spot energy markets; day-ahead and real-time; and some of these service markets that we're going to start administering in the fall; the emergency conditions. Every demand response provides load drop under those emergency resource adequacy constructs, and in the planning environment, ancillary services.

As I go through this presentation, I look at each one of these in turn, and I can pass some judgment on whether I think we have an open, level playing field and have some decent participation by buyers and demand response.

In the day-ahead market, I think we have it right. We do have some vigorous price-responsive demand in our day-ahead market. We also allow the opportunity for demand response to act as a negative generator in the day-ahead market.

In the real-time market, we've got some work to do. I'll talk about one of those barriers here in a minute.

As to resource adequacy, we have vigorous participation. You gave us an order on our proposed resource adequacy construct on March 26th, and we have over

8200 megawatts of demand resources participating in our resource adequacy construct.

As to emergency demand response, you gave us an order on compensation for those resources, on April 22nd. We have a compliance filing tomorrow that we will make on that, but we've seen some indication that this is going to be a useful initiative.

In the next transmission expansion planning process, we're going to incorporate demand resources, so we're moving along the right path, and in ancillary services, we do allow demand response, and, as long as they can provide the service in question, demand response can participate.

So, as we drop in that market and start administering operating reserve markets, we'll be better able to evaluate the participation of demand response in those.

I would mention that we have a vigorous stakeholder process, both at the RTO level, but also through the Organization of MISO States, because, ultimately, demand response occurs at the end use level, and so we really do need the cooperation of the MISO states, in terms of setting retail rates.

That currently is one barrier, the link between wholesale and retail.

As far as the barriers, I think I can identify four, maybe five that are closely linked. There are some technical issues with respect to enabling price-responsive demand in the real-time market.

How do you send a dispatch signal to demand that may be scattered across load zones? You may have it in the lower part of one state and in the northern part of another state. How do we know if that's going to relieve the congestion that we may have?

So, there are some technical issues about sending those kinds of signals to the buyers in the market, and we need to work on that.

The other one that was mentioned this morning, is putting in elasticity, price elasticity demand, as part of our real-time power flow analysis. We haven't solved that one yet.

In the interest of time here, there are a couple of others that have already been mentioned: Should the RTO conduct pilot programs or provide side payments? We're looking at that.

Operator acceptance is an issue that was mentioned this morning, and we got some criticisms about another RTO providing -- I'd only say X-percent of a reserve product in demand response. We see the same at the MISO.

The last one I want to call your attention to, that's really missing, is this notion of locational marginal pricing. David LaPlante said correctly this morning, that LMP should reflect the marginal cost of dispatch and should vary by time and location.

I think we have it right for generators. LMP varies by load; generators by location and time. The problem you have, is on the load side.

Are we sending the right price signals for loads? There's a lot of talk about dynamic pricing, and that's the time-varying portion. What about the location portion?

That's really the low-hanging fruit. In some cases, you may have two or three load-serving entities getting the same price signal, even though they're withdrawing from different portions of the grid. That's not right.

At the MISO, we've allowed, if you're a different load-serving entity, that you can take your price, based on where you withdraw your load. You will see a different LMP, based on your withdrawal points of your customers, so, as a result, we have 311 load pricing zones.

I think that's the right answer. We need to go further than that, though, on the retail side. You still have load-serving entities that serve, say, two or three states, and they are averaging out all their LMPs across their elemental pricing nodes, into one average LMP price.

That's the signal that these customers get. That's a retail/wholesale issue, and the OMS is working on that, as well.

But this whole issue of locational prices for loads, gets missed, and I think we've got it right. Thank you.

MR. KATHAN: Thank you, Michael. The next panelist is Joyce Reives, Director of DPL Energy Resources.

MS. REIVES: Good afternoon. I'm going to follow my written comments, but not read from them.

By way of background, we are a subsidiary of DPL, Inc., and affiliate of Dayton Power and Light. We've actually been operating as a generation provider since Ohio became competitive in 2001, as a large provider of generation service.

It became kind of a natural progression to go into the demand response markets, so we have been serving customers as a curtailment service provider within PJM, although I think the issue is the same since March of 2008.

I will also say that our intent is to find a business model that works, and take it outside of that region, into the rest of PJM and even into the Midwest ISO, once those programs are up and running.

We are obviously supportive of the concept of demand response. We appreciate the involvement here today, think it's good dialogue, and as an affiliate of a utility and a CSP, we kind of see all angles of the topic, therefore, we feel as though we have some angles that not everybody may see.

In response to addressing barriers, there are two I want to address today: The first and largest, is actually in working with customers, getting them to understand the opportunity that exists for customers to ultimately save money on their energy bills.

While there are some exceptions, for the most part, customers simply do not see price signals. Most of the retail rates are a legacy of historically regulated, fully integrated utilities.

Pricing options such as time of day and critical peak pricing, are not widely available, therefore, they just pay the same price for electricity, regardless of when it's consumed.

Because of that, they don't understand that at different times, it costs more or less to produce electricity. They don't understand that the value changes and they just generally don't understand that the wholesale market even exists.

What demand response service is serving to do, is to link the wholesale market with the retail market, and that proves that when you're out working with customers, as

I do most every day, that proves to be a challenge in getting them to understand that.

If there were price signals at the retail level, I think that would really help to bridge the gap, and it's been talked about today, but I'll hit it again: If consumers really face real-time market prices, then demand response would be inherent, and special programs, unneeded.

While that's a long ways away, there are probably some transitional steps we could take to start to get those price signals into the retail rates.

The second area I'd like to address, is that compensation should only be earned as the result of a real reduction in demand. Some programs, including those in PJM, have struggled to make sure that the curtailment is associated with payment and where there is a capacity payment awarded for having the ability to curtail, penalties, we believe, are not really significant enough to deter those from just playing the odds.

PJM has been fortunate that they've not had a lot of reliability issues, therefore, they have not had a lot of emergency orders to curtail.

While that is great for reliability, it really has not served to verify that all of the demand response signed up to curtail, really has the ability and the intent to do so. Again, as an affiliate of a utility, we kind of see both angles, and we understand that retail customers, in effect, pay for the benefit of demand response, through their retail rates.

Therefore, the utility has both the right and the obligation to ensure that the benefit paid for, is received. As a CSP, a curtailment service provider, we only enroll customers that generally have the ability and the intent to curtail.

However, I have spoken with customers who have a different perception of the opportunity, based on the interactions with other CSPs. This is an area where PJM has worked to remedy. We think there is more work to do, and as other programs come into play, we would want to make sure that those things are taken care of there.

Again, we support the intent of demand response, and certainly appreciate the ability to speak here today.

MR. KATHAN: Thank you. Our final panelist is Walter Johnson, a Principal at the California ISO.

MR. JOHNSON: Thank you for inviting me to participate in this afternoon's session. As was said, I am Principal for the California ISO. I'm responsible for technology strategies.

In general, the activities of mine that are relevant here, are in the area of demand response standards. I operate the Demand Response 365, which is the technology demonstration laboratory we have at the California ISO.

I'm also very active and intend to focus my comments on the work I'm doing with the ISO/RTO Council, on their development of technology standards, relevant to the lowering of technology barriers and communication barriers associated with increasing the participation of demand response across all of the ISO/RTO member organizations, with particular emphasis on the problematic issue of the smaller loads that have been alluded to once or twice here.

Henry, on the previous panel, referred to the ISO/RTO Council or the IRC, as we refer to it. It consists of the ten ISOs and RTOs that operate organized markets in North America.

It's been a standing activity of that group for some years now, to work on collaborative development of technology standards to lower the costs of operating our systems.

Much of that work has been focused in the past on intra-ISO communication, integration of the internal systems that we use. For the market systems and energy management systems, that work has progressed nicely.

Some of the standards have actually been moved into an international forum for recommendation for adoption at that level. More recently, with the emphasis on demand response, we've attacked the problem of standardization in that area.

This is a novel area for us, because it's not an internal ISO issue, as much as it is an internal to external communication problem. In order to get our hands around that aspect of the problem, we've worked collaboratively with the Markets Committee of the IRC and have been focused on reducing those barriers, and, in particular, on enhancing the ISO/RTO control rooms' ability to rely on these small resources.

Those are some of the challenges that we're particularly sensitive to. Historically, these resources have not been focused on the ISO control, or have not been linked to the ISO/RTO control room, because the cost of doing so, has been seen as high, relative to the amount of energy available from any one of the resources.

But without this sort of real-time communication to the control room, the reliability organization has difficulty knowing how much demand response capacity is available at any time, or if a resource has responded to a demand request.

The objective of the IRC's work, is to develop recommendations for technical standards for real-time, two-way communications between ISO/RTO control rooms and small resources that are simpler and less costly to implement than the current requirements that originally were designed for large, typically generator resources.

Our focus is on real-time operations, not on forward markets or the settlements, and metering and verification. There is measurement and verification work going on within the IRC, as well. This was referred to earlier.

For the definition of what we're doing, a small demand resource is typically seen as less than a five-megawatt resource and it can be an aggregation, and that's what the major focus of our work is, an aggregation, typically of 100 megawatts or so or larger resource.

The key is that the resource is not usually dispatchable by the ISO/RTO operator, and there is usually no real-time telemetry available from these resources.

We've identified four patterns for interaction in this communication sequence. They are elaborated in the slide deck, and I'm not going to go through them in great detail.

Let me just say that of the four types, in summary, or in brief, the first is an autonomous resource that automatically senses the state of the grid and reacts. This is analogous to the grid-friendly appliance work that PNNL has done.

This is not dispatchable; it's not visible; it just happens, and we have to trust the autonomous intelligence of the resource.

The second category is resource-initiated demand response, where the resource inquires of some central location, such as a website, for the state of the grid, and determines, if appropriate, it should take some action, and if it does take that action, there's no direct dispatch, other than posting of the information from the ISO.

There's no visibility to the ISO operator in real-time, that the action has actually been taken, other than perhaps an aggregate response visible on the EMS system.

The third category is the bulk dispatch. We see this, for instance, in the air conditioning cycling programs where a signal is broadcast to a large population of resources, but there was no information, a priori, that indicated exactly how much demand was on the system at that time. The dispatch signal is sent out and some response occurs.

Finally, the fourth category that we treat, is what we call precision dispatched demand response. This is analogous to a generator, where you have full two-way communication.

We have real-time telemetry on what's available, we can send the dispatch instruction directly to that resource, and we can see the telemetry response indicating the activity that's been taken.

Under that set of categories, only one really meets all the requirements that the operators would like, and that's analogous to the generators that we currently have. That's the precision dispatched, where there's a control signal, a response signal, and we have locational awareness of where the resource is.

We proposed -- last month, we hosted a technical conference on this subject and requested feedback from the curtailment service providers and aggregators, on how best to approach standardizing this area, realizing that it has been historically difficult to produce a paradigm that is exactly analogous to that.

From the responses that we received, it was fairly clear that the ISO/RTO system operators' perspective of wanting this full-time telemetry dispatchability and measurement of the response, could be applied between the ISO operator and the system aggregator, the utility or curtailment service provider.

But we very clearly got the impression that trying to reach beyond the aggregator to the individual resources, the smaller aggregated resources, was not an area that would benefit from an attempt at standardizing the communications across all the ISOs.

The perception very much was that the opportunity for competition, the opportunity for innovation, lies in that area between the aggregator and their resources, and that it would be appropriate for the ISO/RTO Council to focus on developing standards between the system operator and the aggregator, but not further down to the smaller resources.

We've taken that advice and are developing a set of recommendations that we'll be taking forward, putting into a brief position paper on this. We will circulate it to all the other ISOs and RTOs that are members.

We'll be formulating an adoption plan, talking to reliability organization, and, was mentioned earlier, that could be an obstacle. Looking at local market rule changes, is appropriate, and we will present this for adoption by the larger ISO/RTO Council, as a recommendation, going forward.

So, I wanted to emphasize and I appreciate the opportunity to speak briefly on the collaborative efforts that the ISO/RTO Council is performing in this area, in an attempt to further develop demand resources, particularly these smaller ones that we see as largely untapped in most of the organized markets. Thank you for your time.

MR. KATHAN: Thank you. I'll now open it up to questions. Commissioner Wellinghoff?

COMMISSIONER WELLNGHOFF: Thank you. Mr. Johnson, if you could help clarify for me, two concepts you talked about at the end of your testimony, one was this idea of the precision dispatch. How does that relate to the decision by the ISO/RTO Council group that you spoke of at the end of your testimony, to look at standards, only as between the ISO and the aggregator?

Are you saying that you only need this precision dispatch, vis a vis those two entities?

MR. JOHNSON: The perception is that by using the same mechanisms that we use for dispatching generation, with perhaps an additional locational component, the translation of that into what I call the last mile, the final communication of the final resource, can be left to the aggregator.

There's still -- our intention would be to develop performance standards, as we have with generators, with regard to how that resource actually performs in response to a dispatch or other instruction, but to not be explicit about the technology or the communication protocols, as such, that are used in actually communicating with that dispatcher. We'd still want the information, but in aggregate form.

COMMISSIONER WELLINGHOFF: Thank you.

MR. IRWIN: Ms. Reives, I was wondering if you could elaborate for me on the barrier you mentioned about compensation only being earned if there's a real reduction in demand. Could you speak a little more on that for me?

MS. REIVES: In the PJM program, for example, there is an emergency capacity program. That program allows a capacity payment to take place regardless of whether or not an emergency interruption is ever required. The way the penalties work is, if there's only one or zero or even two interruptions, or even up to five interruptions, if the customer does nothing, they're still in the money.

So what we believe is -- and it's a great problem to have, because PJM has not experienced a lot of reliability issues -- there's really not been a full test of the system to say, if you've got 100 megawatts in an area signed up for for demand response that it actually is going to come on line when it needs to come on. There seems to be this concern -- and I know that it was mentioned this morning -- that gaming isn't nearly the issue that it's been talked about being. I don't know that it is. I don't know that it isn't.

But if there's not been a full test to know that all of the demand response signed up is actually going to curtail when you need it, and the penalty is such that as long as it doesn't happen very many times you're still in the money, I would just say that we're rather suspicious. And based on some of the comments that we've heard from some of our customers in dealing with this issue, I would say that we're rather suspicious.

COMMISSIONER MOELLER: Mr. Johnson, first I want to thank you for hosting in late November at the lab the ISO, and would urge anyone who's out there to visit it, because it was a good session. You put some good technology on display there.

This is a question for every panelist who wants to answer it, realizing that I wasn't able to attend the morning session and I haven't really been fully briefed on it. My frustration has been, why haven't we been able to capture more demand response, particularly from the commercial sector?

The Alcoas of the world -- there isn't anybody quite like Alcoa.

(Laughter.)

COMMISSIONER MOELLER: But the big industrial players who have a longer relationship with demand response resources. I'm frustrated to say that at the residential level it may take technological policy implementation to best capture that market. But at the commercial level -- you alluded to it, I think, in your comments, aggregating it

-- that should be the next low-hanging fruit.

If you have any observations in addition to what you said in terms of your work with the Council and standards, anything we can do or other policymakers -- a very general question for all members as to promoting the capturing of commercial demand response.

MR. TODD: Alcoa's work operation is extremely unique because of its load. But even inside of the Midwest ISO footprint, we've got 11 other locations up to 120 megawatts of basically retail load on the system.

At this point, we have no intention of participating as demand response, other than some of the traditional mechanisms that we've responded with in the past. That is driven by, again, our experience in terms of what the barriers of getting involved with the process are.

The requirements around telemetry, metering, forecasting requirements and the investment in resources in terms of getting them up to speed on how the process is, how it works, and the nature of it, has just basically -- as we've talked to them, we don't see enough opportunity there for them to get engaged inside of that process. What we've looked at is, we know that those locations can participate just like we can physically participate. It's not necessarily a requirement that we should have had to do all the things we've had to do.

Telemetry metering is not necessarily a requirement. We're able to respond right now without some of these added things put in place that would be required at our other locations in order to qualify into the process.

I think, as I look at that from Alcoa's perspective, we're very concerned about the fact that there needs to be a hard look on the RTO level at how does this individual location, how do these individual large consumers, how can they participate? Local utilities, they don't have a lot of motivation in our experience to go out and incentivize with clear market signals binary instructions of: this is how you respond, and yes, you can share in the advantages of getting into the system.

That's where we would ask they move to at our other locations. All other locations don't have the same opportunity. But there is meaningful response they can participate with.

MR. KATHAN: Go ahead, Dennis.

MR. DERRICKS: Commissioner, I think there's a few things.

You talked about the industrials. I think there's a level of knowledge with industrials, with resources that are dedicated to energy management. That has been reduced since I've come in the industry as well. But it's generally a larger percentage of their overall productions costs. Whereas commercial customers in general, it's simply a lesser percentage of their overall costs. And typically over the years, they have been less interested.

Obviously, over the years, bills have been increasing for various reasons. There's also environmental things that are going on, especially some of the chain stores and some of those kinds of things that people want to participate in these types of programs just for the ability to either be part of a green marketing effort, or to really make a difference.

Challenges -- the level of expertise of some of these customers. When you're dealing with an energy manager for these smaller commercial customers, they generally have five or six different hats they're wearing, and energy might be one of the lower priority ones. It simply does take a significant amount of education, even with some of our larger industrial customers. We have to spend a great deal of time to educate customers about why we're doing what we're offering, trying to work with them to develop what the program actually looks like, and then to actually implement it.

Obviously, the smaller you go, the smaller bang for your buck.

MR. KATHAN: Joyce?

MS. REIVES: If I could just add to that, I agree with what both gentlemen said in terms of the knowledge of a typical customer. Alcoa is certainly not typical.

What we see also is that the price of electricity just doesn't hit the radar screen. They are so busy trying to do what their business is. I mean, we were working with a pharmaceutical company, and I can't tell you the number of phone calls and e-mails and things like that. They simply are not listening, because they're not seeing the value of it. Because what they're trying to do is to make a product. That's first and foremost.

Something like electricity, while the price has been increasing, is still a rather insignificant portion of their overall operating costs. Unfortunately, until it rises to where it is significant, I think it's going to be a tough gap to bridge.

MR. JOHNSON: There are a couple of things I might add to this.

In our experience, loads differ. The types of customers differ, clearly. But at the IRC conference on this topic last month, Wal-Mart, for example, indicated they have a $2 billion energy bill. That gets their attention.

So it does depend on the nature. And they're very active, and had some very good things to say about the difficulty with variations among the different markets in which they exist, including some organized, some not organized -- utility-level differences and other sorts of things. I'd encourage that as a topic for discussion, to hear the perspective of someone like that.

Along those lines, we're working in California with some of these other big box retailers, and in particular it's one of those things that matter to them, as we move down into the smaller commercial entities. You do want to make this a painless experience for them.

To that end, the auto DR work the DRRC -- the Demand Response Research Center in California -- has been working on putting in place the capability whereby the facility manager can preprogram the response he wants to make, and then set it and forget it and let the system receive the message when it's useful for some response. And the system responds the day afterwards, and he gets the bill or gets the settlement or whatever it might be.

But I think that's a key element, is to make it very simple and something they can sign up for and sort of walk away from for awhile. But I think that's something we're seeing as a direction, and they've just published this week these standards for the auto DR, the open standards for that, for comment. So I know that's progressing.

MR. KATHAN: Go ahead, Jason.

MR. KLOTZ: I echo what Walter has said. But also we've done some studies of our commercial customers and our large industrial customers. Most of our large industrial customers like to gravitate towards our emergency DR. We have almost 2000 megawatts emergency DR in California. We have about 435 price demand response.

What we're finding is that a lot of our customers in California don't sign up for demand response programs to make money. They signed up for the demand response program because they feel they're doing a larger social good.

COMMISSIONER MOELLER: The dynamic I go back to is the Southern service territory. You have virtually no industrial load down there, similar to the state of Florida. There's virtually no industrial load. If you're going to capture demand response at other than the residential level, it's going to have to be focused in the short term on commercial.

Anyway, thanks to all the panelists again.

MR. KATHAN: I have a question for Michael related to what DeWayne was saying.

Maybe partly out of ignorance -- is demand response able to participate in regulation markets or provide regulation at MISO at this point?

MR. ROBINSON: Not at this point, since we're not actually administering a regulation market. In the fall, yes they can, to the extent that they can verify that they can actually provide a regulation service. Sure they can.

MR. KATHAN: What will be required in order to verify that they can? Is it tests or what?

MR. ROBINSON: I've been removed from this for awhile now. But there are some tests, some verification, and clearly some infrastructure needs -- telemetry, visibility and metering data required. So yes, there are.

But to the extent they can -- my understanding, we've allowed in the tariff, and there is what we see in terms of the value for demand response is really in the provision of ancillary services, maybe not regulation -- more spin and non-spin. Again, as Joyce said, these companies are in the business of producing product or providing some services, not in producing energy. But to the extent they can substitute or reduce their energy during contingencies and they can get some market clearing prices based on that, I think they're willing to do that.

We're hopeful that when we start conducting these markets, we'll see some significant demand response. But in terms of regulation -- I mean, if Alcoa's not providing it, it's going to be hard for demand response to provide regulation reserve. Maybe some pumping loads in California might be doing it, but it's pretty hard to move every four or five seconds.

MR. KATHAN: DeWayne, do you want to say something?

MR. TODD: I guess I would just echo. In order to participate, because we are registered and actively participating in the testing, so we're ready to provide that. We are the only controllable load registered inside of the Midwest ISO that has demonstrated the ability to do it. We have had to put in real-time telemetry, which is constant communications directly off of our load, and we already have metering that was set up at our net interface. But this is additional metering that was required, much more sophisticated, even though from our perspective they could already see what we were doing and what our load was.

Because of the modeling requirements, there's additional metering in order to get engaged with the market SDR. We have to have a five-minute forecast we're constantly providing as a service in order to participate in that. That's used to balance off where our response is versus where we want to be. It has significant settlement implications, because where we were a single injection or withdrawal from the system, a single node on the system now becomes multiple nodes. So the settlement process became significantly more complex as well as the bid process.

Those are all the elements that went into us getting ready to participate. At the end of the day, you know, our facility, everybody there will tell you we want to make aluminum. We're not in the business to provide demand response. But we do see the opportunity. It is an opportunity to mitigate our external energy costs, because at the end of the day we're going to buy far more power than we would ever sell into that market just simply because of the dynamics.

Aluminum is at an all-time record from its London Metal Exchange costs. We compete locally, so the cost is set on the LME, and that's the benefit we get. But we're still seeing these significant opportunities, as I say, if we don't make aluminum predicated with power costs.

MR. PALMER: I have a question first for Mr. Johnson.

When you talked about new communications protocols that the IRC is working on, I presume you're aware of the requirements of the new energy legislation for interoperability standards being developed by the National Institute of Science and Technology. I know from what I've heard that the RTOs and ISOs were instrumental in some of the movement to standardize a lot of protocols, particularly between control rooms and that sort of thing.

I'm just curious as to how conscious you are of trying to maintain open systems and not lead to any type of decisions that would lead to some kind of stranded investment.

MR. JOHNSON: I think we're very aware, and it's part of the overall strategy that we're using in the standards development process, that we're trying to lower costs. To that end, we do want to adopt -- and some of the areas we've gone in, in fact, demand response is an interesting area. Because there's almost a surplus of possible standards rather than a shortage of standards. We had to create some in some of these other areas.

Many people don't face the issue, and haven't historically faced the issue, of integrating market systems with energy management systems, since ISOs have existed. We started to take that up. But some of these other kinds of areas, there's much more developed work.

We're quite open. It's certainly part of our strategy to make the most intelligent use of existing technologies, existing standards -- nothing that would have the net effect of either stranding assets or otherwise increasing costs would be our preferred solution. That's certainly true.

And one of the things that we're having that's a challenge is keeping up with all the different activities. There's an awful lot of work being done from an awful lot of different locations, including other parts around the world that are working in this area.

So I can only hope that we're managing to capture or stay in touch with as many of the initiatives as we can.

But that's certainly our intention.

MR. PALMER: I also wanted to ask Mr. Todd -- you had mentioned that at times in your variation of power that you take off the grid at times, you increase your consumption to meet the requirements of the system. That struck me as interesting for a couple of reasons.

First of all, we've seen a lot of projections for the amount of variable generation that's going to be coming on to areas of the grid, particularly Cal ISO and the Midwest ISO. I'm just curious as to what extent you think -- and this is really for all the panelists, but you triggered this -- the question is where you think there might be opportunities to take advantage of essentially free energy and free electricity at night when, let's say, there actually may not be generation, rather than turning off wind machines, for example.

You might be able to find some use for that energy and how demand response, as a subject, somehow sort of incorporates using that power at that time.

MR. TODD: Well, for us, there were two opportunities. One of them, since we're very well balanced with behind-the-meter generation and load, we can obviously drop our generation down, and the load becomes buying from the system.

We also have the mechanism to basically take our pot lines into an overramped condition. The physical structure and the night ambient air conditions dictate how, the technical limitations of the buswork -- you can run it up for a short period of time, four to six hours during cooler time periods to take additional load in, have additional production. We often use that. It's a very normal process for us. We use that to offset lost production that may happen during the on-peak period. We are shaving line production during the day when prices are high.

So Warrick is kind of our flagship spot inside of North America that's looking to say, how do we take these experiences to other smelters, if the opportunity is available there. At multiple North American smelters, that opportunity is not available to do a simpler process and get cheaper power during certain periods of time. But that process lends itself to it with the directly-connected production. It's equivalent to how much power we're putting in.

MR. KLOTZ: In California just last year, we sponsored a $25 million pilot program to implement what's called permanent load shifting. In particular, we're looking at thermal energy storage and its relation to wind in the off-peak hours.

We are also funding a study, working with -- or funding a study, hopefully -- in collaboration with the CEC and CAISO on how dynamic rates may help incorporate off-peak energy usage to help integrate similar intermittent renewables.

MR. ROBINSON: I would add, in DeWayne's case, he does reemphasize and support my argument earlier that he's seeing the price. He's at a particular location. He's got an LMP, and it varies across all the hours of the day. So he's getting the LMP that we are projecting out as the sole representative for that particular load-serving entity. He is getting the right price.

As I said earlier, we allow our load-serving entities to receive their own price as well, based on where they withdraw from our system. But the next step is where the link or the breakdown between wholesale and retail is. The load-serving entity is getting its own price. But if it's averaging those LMPs across all of its areas, the other customer is just getting an average price. We need to work with the Organization of MISO States to link those up.

MR. PALMER: Thank you.

I think sort of a related question is, DeWayne, you did a lot of work participating in the regulated market, but you decided not to because it really wasn't your business. There are a lot of people who are in the business as demand response providers and aggregators.

I'm curious whether certainly, in addition to a big load like yours, there are a lot of distributed loads that, if aggregated, might potentially be able to act in the same way. I know Commissioner Wellinghoff likes to mention the possibility of plugging in hybrid vehicles some time in the discharging cycle.

There are a lot of other energy storage devices already existing, like freezers and refrigerators in buildings. I'm curious again, just looking at it from the feasibility point of view, if any of you see some possibility of further development along those lines.

MR. TODD: I don't know if we miscommunicated. We are going to participate as a regulation resource, because the reality is, we think that we have lost efficiency. But if we can average, say, our smelter is 450 megawatts, and we can still average 450 while providing regulation, we have an efficiency impact. That's at our Warrick location.

Our other locations is where we have kind of looked at and said, those are industrial customers. We don't see the same magnitude of megawatts.

MR. KLOTZ: The CPUC funded a pilot project with LDNL and SCE using SCE's extensive load control AC cycling. What LDNL has done is, they've been able to take a group of AC units and curtail them for five- to 20-minute periods, and provide a sort of spinning reserve to the CAISO.

This is just a pilot project under WECC standards. Demand response currently in California cannot supply spinning reserves, but this was an attempt to show WECC that it can be done.

MR. JOHNSON: I might add that we're also integrating the dispatching of that resource into a test of our market systems, since we don't have the ability to operate that way, to simulate the end-to-end process of dispatching that resource as you would any other ancillary service, and completing the loop.

MR. KELLY: I wanted to ask this panel a question which I asked an earlier panel. Is there something FERC can do on these barriers to demand response?

I mentioned to the last panel that we had proposed four demand response activities in the current rulemaking, and we were doing annual demand response reports. Congress told us to do an assessment of an action plan. We're collaborating with the states.

I listened to what you said, and I did identify needs. But I wasn't sure if those translated into FERC actions. For example, Mr. Derricks said we needed a capacity aspect in MISO. I didn't know if you were calling on FERC to bring one about. That's been the subject of a long discussion. And Ms. Reives said, well, we need penalties large enough to make demand response real. I didn't know if those were retail set penalties or MISO set penalties that FERC could effect.

But the general question: is what we're doing, what we have on our plate now, various activities, about right? And recognizing this is a panel of a more diverse set of ISOs compared to the northeast ones, which are all modeled on the original three tight power pools. There's some diversity, but California, MISO and SPP are even more diverse in their designs.

Is there something FERC should be doing beyond what we're already proposing to do, or is the action now in the hands of the ISOs, the customers, and other parties?

MR. TODD: Again I think we very much appreciated the fact that demand response is a big priority for FERC in terms of getting that to the RTOs. From our perspective, we feel like there's times when FERC has examined the reasonableness of the proposal the RTO is proposing to include demand response, giving them the opportunity to provide services -- as Mike said, allows them to participate.

The current model inside the Midwest ISO models the demand response just like a generator. It's identical to a generator. The demand response is not identical to a generator. And so more than looking to say, is this reasonable for a demand response, is the question of whether it's practical for a demand response to take that and implement it and use it.

I think part of our belief is that the barriers of getting involved with the process is why there's only one demand response Type 2 involved. And going through with the process at this point in time, and understanding that a lot of people will watch and see what happens, and then as those things are learned about we would look for FERC to say, to make sure that in each RTO area, as was said earlier, there's a high-level commitment somewhat focused on reaching out to industrial loads. Because there's not as many stakeholders speaking on their behalf inside of the stakeholder process inside the RTOs, because most industrial loads are focused on their industrial activities and producing product rather than working on an RTO involvement.

We don't know what the answer is. But any program needs to have clear signals, binary communication of what the actions that the end user can take, then hears the benefit. There needs to be a real, significant benefit that reflects exactly what's happening in the market at that point in time. Those are essential elements that we would look to the FERC to insure that's being incorporated into the tariff and business practices that are taking place.

MR. KELLY: Others? Mr. Klotz.

MR. KLOTZ: I spoke with David Kathan over the phone last week. He mentioned he was very interested in our load impact protocols and our cost-effectiveness protocols. I would extend an offer to staff members of the FERC to come and learn from the Energy Division on how those protocols work. That might be one step in collaboration.

I think collaboration is one part of what can be done. You're going to see within the next month a goals document on demand response coming from the CPUC. In Section 5 of that goals document, if it's approved by the Commission, there will be a call sent to FERC to request collaboration and information from you on how we can, with the CAISO and the IOUs and our other stakeholders within the state, create a system for direct, bid-in demand response. Collaboration is one big thing that can certainly help us.

MR. KELLY: Thank you. Mr. Robinson.

MR. ROBINSON: I'll respond to both of those comments.

I think what DeWayne said is fair. We will start conducting ancillary service markets in the fall. I think it behooves us, from the Midwest ISO's point of view, to assess as we develop these markets and start conducting these markets, whether the technical requirements, the design rules are in fact more active demand response than the rules we have in place.

But we should look at whether there is anything we can do to sort of level the playing field, as DeWayne said, and not treat demand response as a generator. That's one.

Then to what Jason was saying. Anything you can do to support the Cal ISO has one state to deal with. We deal with 15, as you're well aware. The Organization of MISO States has this MWDRI initiative -- Midwest Distributed Resource Initiative. Anything you can do to support that initiative, which is again focused on providing the link between wholesale prices and retail rates, would certainly help us.

MR. KELLY: Does anybody else want to speak to that? You don't have to.

MS. REIVES: I'd like to add I don't think it's anything new. What FERC is doing in terms of getting the topic out there -- and I think the more that it's talked about, and I know at the PJM level there's been a lot of emphasis on demand response and massaging the programs -- I think the more that that's done, the better off we are, the more we're going to make it down that path.

I don't know that there's anything specific that I would say that FERC should do. But I think to have the topic out there and talked about, and maybe it's kind of a sharing of best practices -- you know, we do it this way;

this one does it this way -- and while you've got limited ability to force it on the states or to force it on the different ISOs, there is the ability to get the topic out there. And I think the more we get the topic out there, it would be nice to have a way to get the topic out there to more and more customer groups as well.

But I think whenever the topic is talked about, it is advanced. I would encourage the communication and everything to continue.

MR. KATHAN: Jason has already indicated I'm interested in impact protocols. I appreciate your suggestion.

I just have a general question about those protocols. Are those only applicable at the retail level, or can they be applied at the other ISOs, RTOs, at more of a wholesale level? And is this something that could be used and possibly adopted in other areas?

MR. KLOTZ: That's a good question. Currently the load impact protocols that are developed are for CPUC and ISO planning purposes for resource adequacy and long-term planning and program design. But in Phase 3 of our demand response rulemaking, we will be working with the CAISO to create wholesale market, CAISO-specific load impact protocols that they can work with for their day-to-day operations. Hopefully those impact protocols will translate to the other ISOs. Hopefully they will be helpful.

MR. KATHAN: Thank you. Any other questions?

MR. KELLY: I did have a question from earlier, Mr. Klotz.

I think I heard you say that the lack of a forward capacity market in the Cal ISO is a barrier to demand response, if I understood you right.

MR. KLOTZ: Forward energy market. We don't have the day-ahead market right now.

MR. KELLY: Okay.

You also said that you had a goal of getting, by 2012, you have enough smart meters that you could shift all California customers onto dynamic rates.

MR. KLOTZ: All of California's retail residential ratepayers under the IOUs will have smart meters and home area networks within their homes by 2012. We expect to roll out a dynamic rate for those customers at the same time.

We are hamstringed a bit by Assembly Bill 1X, which was put into place after the energy crisis to freeze the first two tiers of the residential rate. But we are working through. We had a number of proceedings to look into how we could get around that and what can be done for a more dynamic rate to our retail customers.

MR. KELLY: Has there been any discussions of how the actions relate, having a forward energy market and in effect real-time pricing, whether they cooperate or co-exist or conflict?

MR. KLOTZ: Our assessment of how residential retail ratepayers will respond to dynamic pricing -- they'll probably respond more at the day-ahead level than they will in the real time. They will manage their energy use probably the day ahead through some sort of protocol that's put into their home area network.

So a day-ahead energy market is important for AMI to work.

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

Turning control of your production process over to MISO seems like an amazing step that not too many industries, I would guess, would want to do. When you say turn over control, does that mean they would decide when to shut down your smelters?

I don't know the aluminum business well, except I think I know that you don't just turn them on and off. It's like turning a huge ship around. There's a big lag in the system that has to be taken into account.

The counterpart to that is, I think you said you had a 500-megawatt generator for a 50-megawatt load. But is part of shutting down MISO's supply of electricity to you starting up your generator to fill the gap, so that your production process feels a net effect of zero?

The reason I was thinking that, in the interest of full disclosure, as we talked this morning about putting a value onto demand response, if there's a value in terms of say savings of carbon emissions, and some such set of demand responses was actually substituting your own carbon emissions for MISO's carbon emissions, that would be something to take into account.

I realize I've mixed in three or four questions.

(Laughter.)

MR. TODD: I think the first piece of that, turning over control to MISO -- fundamentally, the smelting operation wants to run on a smooth, even base its electrochemical process for best efficiency. It's like a boiler. It wants to run on a flat, even load and output.

Three years ago, when we began to talk about doing shaves, which is a distinct load drop -- 30, 50 megawatts, perhaps 90; we're not talking about interrupting the load, we're talking about curtailing it -- we take the smelting piece of it, which is about 460 megawatts. The remainder is RPD, which is rigid packaging, their casting into ingots, the rolling can stock -- other processes that are at the facility. That's what gets up to the top 550 megawatts so we do have 550 of load and generation. But the smelting component is about 460 of that.

So when we broached the subject, they said: well, you can't do it. It cannot be done. You can't make load changes every day. We're talking about two to three times a day. You'll mess up the process. The efficiency will go down. You'll have premature failures of equipment.

So we began to get involved with it, and we scaled up and continued to scale up. Until last year, like I said, we documented about 1800 events and we had record current efficiency, the best performance.

We're a benchmark organization worldwide, Alcoa, for operating systems stability and efficiency. So the processes were able to do that. And that's all done manually. That's the way we do it today.

Where we talk about turning over control, what we are doing is, we redesigned our control system for the smelting operation to where it operates to a set of target production levels of aluminum. It operates to a target megawatt value instead of a target value of aluminum. It's fundamentally different.

What we do is, we allow MISO to give us the target for megawatts. We're not going to let them take us all the way to zero, because physically we can't do that anyway. The mechanical nature of our transformers won't allow us to curtail all the way down. We think we can get in the 90-megawatt range that we would allow MISO to send us a signal. They would tell us to go to this target, 460 to 440 to 430, the specific spot, and our control systems would take us there. Our control systems have fail-safe mechanisms in them that are going to protect the process to make sure that the process isn't going to self-destruct or create a catastrophic event that would shut down production.

So the turning over is, they're sending us a signal. Now, instead of what was a big concern two or three times a day, it's a four-second signal, and we're responding to that on that four-second interval. That is a huge paradigm shift for our location, for personnel. But they see the opportunities. Obviously there's a significant financial opportunity there, and fundamentally a smelter becomes like a huge battery in that it can respond and increase power levels and drop power levels off in that manner.

We're still trying to introduce the notion at other smelting locations. Some have stability issues. Some are reluctant to get involved with it. On the other hand, we are globally competitive. We have smelters in the U.S. that have been shut down because basically of the price of power in the U.S. Alcoa builds new smelters overseas, and we have other marginal smelters that will be looking at this as an opportunity to stay in business in the U.S. when otherwise they would have to shut down because of operating costs.

I think that was two of your questions.

MR. KELLY: Do you have backup generation that you run to compensate for the MISO power you don't take?

MR. TODD: Basically our generation pretty much perfectly balances, so that if we lose any production from our generators, we have four coal-fired generators. We also have our own coal mine that supplies that. But if we lose any part of that generation, we're immediately buying off of the grid, right now from Midwest ISO. During an extended outage, we may get a bilateral agreement or something like that.

So the Midwest ISO does not dispatch our generation. But we internally manage that. However, what we have got under our control is on our load side. Given that they're giving us a set point that our control system responds to, we'll move around. And honestly, we are still testing the process and understanding what our limits and capabilities are, with the intent to extend it to other locations.

MR. KELLY: Thank you.

MR. KATHAN: I have actually one last question. That is, I asked the same question to Rob Pike on the previous panel. The question was about how to get over the knowledge gap.

We talked about this somewhat on this panel. But I'd like to ask this direct question: is there a role for FERC to help get that knowledge gap crossed? I offer it up to anyone on the panel.

MR. KLOTZ: In California, we have energy efficiency and we have demand response. And until this year, marketing and outreach for energy efficiency and demand response were two separate events. So our IOUs would go to a customer, and they'd present the energy efficiencies. Several weeks later, they'd come by and present demand response. Didn't make too much sense.

So, we now have a proceeding where we're trying to integrate marketing and outreach. Marketing and outreach and customer knowledge are very important. Most of our customers on our demand response programs feel they have a general understanding of baseline information, and they kind of understand how the programs work. But a lot of the customers who are reticent to sign up say it's too difficult, it's too complicated.

So if FERC's going to help with the knowledge gap, I think some sort of outreach to residential customers, to small commercial, large industrial customers would certainly be helpful, so they understand exactly how demand response works. In California, all of our large C&I customers have 15-minute interval meters. Soon all of our residential ratepayers will have one-hour interval meters. Most of them don't understand demand response, and it would certainly be helpful if we could get some help nationwide on informing customers on how demand response works: how they receive incentives, how a dynamic rate works and what it means to them.

MS. REIVES: I would agree. Whatever we can do to aid that communication or that education would certainly help. We certainly alone have not found a way to really educate the customer, convince the customer that this is something that they can do, for the most part.

I will say that in Ohio, there's some legislation that's been signed, but not quite law yet, that is to have a lot of initiatives in it on energy efficiency and renewables and things like that, that I think is going to advance metering and advance some of the other efficiency opportunities. So I think some of it's coming.

But I would certainly agree that whatever the FERC can do on a nationwide basis to advance education would, I think, be well spent.

MR. KATHAN: Okay.

I think we've reached the end of this panel and the end of the day. For closing remarks, I'd just like to thank all panelists for their participation. This has been very useful, very helpful, and I look forward to working on this subject in the future.

Anything anybody else wants to add to that? Commissioner Wellinghoff.

COMMISSIONER WELLINGHOFF: I've got quick closing remarks.

I would also first like to thank this panel and all the previous panels for the information they've provided. And I'd say this is the single best technical workshop I've ever attended.

I would also like to give commendation to the staff here. What you've done and the questions you've asked and the information you've elicited from these people who had information to provide was extremely valuable.

An area I'd like to focus on is an issue that came up in some of the panels that was talked about in this panel and talked about by Andy Ott on the previous panel: the issue of participation of states in the wholesale markets, where some states -- their customers aren't given the opportunity, or it's uncertain whether they have that opportunity. And there are issues -- for example, Andy talked about just registration of customers, and making that clear, giving the example of Indiana.

I just heard from Jason about the potential goals paper that's going to come out in California, and the potential recommendation that CPUC has adopted to allow customers to participate directly in the wholesale markets in the Cal ISO. I'll tell you -- your indication, Jason, that you're looking for some cooperation and collaboration with FERC; I'll give you all the collaboration and cooperation you possibly can want.

I don't want to speak for my fellow Commissioners. But I have a feeling that I can get all my fellow Commissioners on board on that as well. I'm very excited about that prospect, because I think it only gives customers an additional tool, an additional opportunity to control their costs and to work with the system both at the retail and the wholesale level, to give them greater opportunities to insure they can manage electric prices. And I'm very excited about that.

Overall, what I heard today is: the promise is immense, the economic potential for savings is vast, and the barriers are not insurmountable. I'm very encouraged by today, and I want to thank everybody again. Thank you.

COMMISSIONER MOELLER: David, I'll echo thanks to the staff for the logistical scheduling challenges that are involved in putting this on, and of course to our panelists this afternoon and the ones I did not hear this morning for their efforts in coming here and providing information. And I also want to add thanks to my colleague, Commissioner Wellinghoff, who has shown so much leadership in bringing this issue to our attention and, I think, the attention around the country.

As I stated earlier, we need this resource. We don't really have a choice. Demand response is going to be necessary as we live through the times of uncertainty as to where our nation and internationally we are going on carbon policy. Until we figure out where that's all headed, demand response will be one of the essential elements of making sure that we still have, hopefully, affordable and reliable electricity for consumers in the country.

As all of you alluded to, but I think it was probably highlighted a little bit more by Ms. Reives, the fundamental 30,000-foot problem we have here is that consumers often receive either inaccurate, outdated, stale or a combination of those characteristics in their price signals. Until they start getting accurate price signals, we will be hampered in our ability to harvest the benefits from demand response.

I'm hoping that's something we can all work on, whether you are in the private sector or at the state level or the federal level, regardless of our jurisdiction -- trying to educate and inform consumers that the value of electricity varies greatly in location and time of use. Accurate price signals will then hopefully lead to rational behavior that benefits the entire system in a more efficient allocation of resources.

The irony of today is that our focus is on organized markets. Yet I'm a firm believer that organized markets are a more efficient way to send those price signals that allow for demand response to be taken advantage of, and perhaps our next technical conference should be on demand response in the areas that do not have organized markets.

With that, again I thank everyone for their effort, and look forward -- certainly you can add my name, Jon, to those who would be willing to aid in this effort.

MR. KATHAN: With that, I'll close the conference. Thank you very much.

(Whereupon, at 4:35 p.m., the technical conference in the above-entitled matter was concluded.)