BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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Hearing Room 2C

Federal Energy Regulatory

Commission

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Washington, D.C.

Wednesday, January 25, 2006

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

PRESIDING:

DAVID KATHAN

FERC STAFF

P R O C E E D I N G S

(9:00 a.m.)

MR. KATHAN: Let's get started. Good morning. My name is David Kathan. I'm with the Office of Energy Markets and Reliability here at the Commission.

Today the Commission is holding a Technical Conference on Demand Response and Advanced Metering. The purpose of this Technical Conference is to collect information, insights, and perspectives on demand response and advanced metering, in order to comply with the reporting requirement placed on the Commission in the Energy Policy Act of 2005.

The Energy Policy Act of 2005, required the Commission to prepare an annual report on demand response within one year of enactment. Section 1252(e)(3) requires that the Commission prepare a report that reviews and identifies on a regional basis, the following issues:

Saturation and penetration of advanced metering communication systems; existing demand response and time-based rate programs; annual resource constitution of demand resources; potential for demand response as a quantifiable, reliable resource for regional planning purposes; steps taken to ensure that demand resources are provided equitable treatment in regional transmission expansion planning and operations; and, finally, regulatory barriers to improved customer participation in demand response, peak reduction, and critical peak pricing programs.

We are seeking information on all of these areas in today's conference, particularly a discussion of the regulatory barriers to demand response and advanced metering.

Note that the Congress did not limit our inquiry to wholesale issues or to FERC-jurisdictional utilities. Our report will span retail and wholesale demand response issues, and will cover the entire U.S., including Hawaii, Alaska, and, yes, ERCOT.

(Laughter.)

MR. KATHAN: This Technical Conference is one of several means of collecting information that Staff is undertaking. We have already received multiple comments in response to early requests for comments.

We will also be conducting a survey on advanced metering and demand response programs. This survey should be released shortly, and we have selected UtiliPoint International to assist us in the implementation and analysis of the survey.

Before I move on to housekeeping items and move int the meat of the conference, I wanted to offer Commissioner Brownell and Chairman Kelliher, a chance to offer any additional comments and/or thoughts. Do you have anything you want to add?

COMMISSIONER BROWNELL: Good morning, welcome. We had kind of an exciting, I think, preliminary kickoff yesterday at the town meeting about demand response.

As I said there, the stunning thing to me was, during the 20 or 30 Technical Conferences that we had four and a half years ago when we first got here, about RTOs and market design, the only thing that everybody agreed on, was that we needed demand response as part of the market, not, as someone said yesterday, as a sideshow.

And so I kind of thought that was going to be the easiest part of our job. Okay, everybody agrees; we'll have demand response in a couple of weeks.

Four and a half years later, it's like looking at infrastructure in California and Southwest Connecticut; not a whole lot has really happened to institutionalize demand response. We have a lot of programs and pilots and programs and pilots, but we have very little, kind of institutional codification in the market designs themselves.

So I'm really looking forward to the Conference, and I hope that we'll learn a lot, and we will move the ball forward. Mr. Chairman?

CHAIRMAN KELLIHER: Thank you. As Nora said, one of the acknowledged weaknesses of electricity markets, is lack of effective demand response. That has implications for wholesale markets, leads to greater price volatility in wholesale markets, but, ultimately, a demand response program revolves around and is centered on the retail consumer.

The key is that certain demand response programs also involve a wholesale sale, and what's important and the challenge really, for FERC, is to work with the states. We respect the state jurisdiction in this area, we know they have the retail consumer.

We have to develop complementary approaches, though. Federal and state regulation has to work together, and encourage greater demand response. So I look forward to this meeting to see how we can do that.

Welcome back to Allison, and I want to welcome also the state regulators, our state colleagues who are here, and the other panelists. Thank you.

MR. KATHAN: Thank you. Also, before I started, I wanted to acknowledge several members of the Commission Staff for assisting me on this project. On my right is Carol White, and, to her right, is Eileen Merrigan. They are both with the Office of Markets, Oversights and Investigation, and further on to the right is Norman McOmber, also with the Office of Energy Markets and Reliability. To my left, I have Aileen Roder and Michael Goldenberg, both with the Office of General Counsel here at

FERC.

Several housekeeping items: First, the Commission's assessment of demand response and advanced metering is in Docket AD06-2. A full set of comments, notices, and a transcript of this Conference, which will be available after it's made public, will be found in this docket, and in the E-Library system on the FERC website.

We have included in this particular Technical Conference, four additional dockets in this Notice, and because they relate to demand response and the ISOs, and they will be possibly speaking on those dockets today --

In addition, for the people watching the webcast of this Conference, the web page associated with this Conference contains an agenda for the Conference, along with many of the presentations that will be given by the panelists.

Second, the schedule for this Conference is very tight. We have many panelists and lots of things to discuss.

We'd like to hold the panelists, if possible, to five minutes in their prepared remarks, and please make full use of your time to give your thoughts and perspectives, and, as much as possible, to keep your descriptions of your organizations or your bios, to a minimum, so that we can get the full content that we're looking for.

We're also keeping track of time. I've asked Aileen to be our timekeeper, and she'll put her name tag up when there's approximately one minute left, about four minutes into your talk, and we will try to follow that. After each panelist talks, we will have a Q&A session for the remainder of the session.

Third, I'm not sure we need it yet, but just want to let everyone know that there is an overflow room next door in Hearing Room 1, which will be a live video feed of the Conference, so that is available.

Finally, there are no food or beverages, except water, allowed in the Commission meeting room.

Please also silence your cell phones, thank you.

I also want to introduce -- we also have Sudeen Kelly, one of our other Commissioners, who has arrived. Do you want to say a few words before we start?

COMMISSIONER KELLY: I understand that we have 250 people who had signed up to attend this, and I think that's a remarkable level of interest. Thank you to the panelists who have agreed to spend their time today briefing us. We look forward to what you have to say, and, as you can see, you have a very big audience. Thank you.

MR. KATHAN: Thank you. Let's begin with our first panel. The first panel will focus on the broader issues and policy implications from demand response.

We have invited six panelist to provide guidance on these issues and challenges concerning development of demand response resources. Our first panelist is Chuck Goldman. I have asked Chuck, as he has done in other similar conferences, to provide an overview of key demand response issues and challenges.

His presentation should serve as a good starting point for the rest of today's discussions.

(Slides.)

MR. GOLDMAN: Thank you, Dave. It's a pleasure to be at the FERC this morning. Dave did ask me to talk about some of the demand response issues and challenges.

I'm a staff scientist at Lawrence Berkeley National Laboratory, and my work is funded by the Department of Energy's Office of Electricity Delivery and Energy Reliability.

In the next 15 minutes or so, I hope to do that. In terms of what I hope to cover, I'm going to provide a little bit of a regulatory and market context for demand response, talk about some of the existing load response capability in the U.S.; try to present sort of, I think, a useful typology to think about the types of demand response options that are out there and how those interface with the retail and wholesale jurisdictions and programs.

Then to sort of lay out what I think are sort of five large issues and challenges that might frame people's thinking about where we are and how we might want to proceed, in terms of regulatory and market context, for the last four or five years, there's been very strong federal policy support for demand response at the FERC, and sort of as well in the recent Energy Policy Act.

At the state level, interest varies among state public utility commissions. In this chart, I cite several examples of recent initiatives.

There is a reemergence of demand response as part of resource planning in the Pacific Northwest. There are a number of states that have considered real-time pricing as the default service. Examples include: Maryland, New Jersey, Pennsylvania, and New York. These are examples where customers are going to see -- large customers will see time-based pricing.

And there's a lot of initiative in the West and in California, to look at a variety of demand response initiatives.

In terms of the overall market situation, though, there are adequate to high reserve margins in most parts of the country. There are a number of hot spots that have been the focus of a lot of activity: In Southwest Connecticut, in Southern California, and New York City.

But in the last three or four years, price volatility in most regional energy and capacity markets, continues to decline. Prices have gone up, but the actual volatility -- we haven't seen major outbursts in prices since the last in 2001.

Underlying this is sort of a gradual decline of the legacy load management programs that have existed for the last ten or 15 years in this country. I'll show you a graph about that.

The other big trend in the last three or four years, is the increased role of ISOs and regional transmission organizations in the administration of load management programs.

This chart illustrates -- it's from data from the Energy Information Administration, and they collect this data annually from utilities and retail suppliers that must report it.

The chart sort of picks two years out, 1996, which is sort of the highwater mark of load management capability in this country. What you can see is that -- my summation would be, today, at present, we have sort of limited demand response capability in the U.S.

The demand response potential in 2004, was about 20,000 megawatts. That represents about three percent of U.S. system peak demand.

Utilities report spending about $515 million on these programs that are out there. These programs include both direct load control; traditional, interruptible curtailable rates; other types of load management programs; pricing initiatives.

The data collection instruments are not great, I'm going to tell you. In the interest of simplicity and aggregation, we have lost a lot of the underlying detail about what's going on on the ground.

The total load management capability has fallen by about a third since 1996. The factors that affect this trend include: Fewer utilities offering load management programs. In 1996, about 407 utilities reported offering such programs; in 2004, about 273.

There has been declining enrollment in existing programs in a number of utilities, and there is the changing role and responsibility of the utilities in states that have restructured, in terms of whether it's appropriate for them to continue offering these kinds of programs.

And the underlying supply/demand balance affects this situation, as well, the increase in generating capacity and reserve margins.

The DSM information report about industry participants to the EIA, does not fully reflect the current demand response capability in the U.S. There are some entities that probably do not report and are not required to, but it gives you a good feel.

I'm going to skip this slide, in the interest of time -- same information.

The typology that I wanted to present to you to think about: There's a lot of ways to classify demand response, or to think about them, you know, in terms of how they're triggered, reliability events, high prices.

Here's one that I think is maybe useful to think about -- the jurisdictional issues of wholesale and retail. There's a group of programs, activities that we'd call price-based demand response.

These efforts refer to changes in usage by customers in response to changes in the prices that they pay. These would include: Real-time pricing, critical peak pricing, even time-of-use rates.

And the customer's load modifications in these efforts, are entirely voluntary, and it's the basic, underlying retail rate, or, if they are in a competitive market and have a retail supplier, it's the kind of deal they have with their retail supplier.

Another group of activities can be linked toward incentive-based demand response programs. These are programs that are established by load-serving entities, utilities, or regional grid operators.

In these programs, they give customers load reduction incentives that are separate from or additional to their underlying retail electricity rate, and that's the key point.

The load reductions are needed and requested, either when the grid operator thinks reliability conditions are compromised, or when prices are too high in the wholesale market.

Over the long term, the maximum benefits of demand response will come about as the entire range of demand response options, both price-based and incentive-based programs, are made available to customers.

This is my list of the five challenges, and I'm going to through some -- present some results from our research in a number of these areas, after I talk through this slide.

The first one and probably maybe -- is fostering price-based demand response. This is fundamentally a retail regulatory challenge for state PUCs.

By making available, time-varying pricing that lets customers take control of their electricity costs, we're going to have more efficient pricing. And it's really probably the highest priority. It's of the utmost importance, and an area where the efforts are very mixed across states.

The second general area is improving incentive-based demand response programs to broaden the ways in which load management contributes to the reliable, efficient operation of electric systems.

Incentive-based demand response programs can help improve grid operation, enhance reliability, and achieve cost savings for load-serving entities and their customers.

The third general area is strengthening demand response analysis and valuation, so that program designers, policymakers, and customers can anticipate demand response impacts and benefits.

Demand response program managers need to be able to reliably measure the net benefits of demand response options, both costs and benefits, to ensure that they are effective at providing needed demand reductions and are cost-effective to consumers.

The fourth general area is integrating demand response into resource planning, so that the full impacts of demand response are realized. Such efforts help establish expectations for the short- and long-run value and contribution of demand response in different electric systems, and they enable market participants to compare demand response options with other alternatives.

The last area is adopting -- increased adoption of enabling technologies. Right now, to realize the full potential for managing customer usage on an ongoing basis, on a sustainable basis, given the innovations in communications, control, and computing, it's going to be necessary to really automate a lot of demand response activities.

Innovations in monitoring and controlling loads are underway. They offer an array of new technologies that will enable substantially higher levels of demand response in all customer segments, and broader participation.

They will allow more types of customers to think about this as a reasonable option, but it's going to take time and effort to get there.

So, now, I'm going to go into some more details in each of these areas. The first one is fostering price-based response.

Currently, there is a disconnect between short-term, marginal electricity production costs and retail rates paid by most consumers. This leads to an inefficient use of our resources in the electricity sector.

Because customers don't see the underlying short-term costs of supplying electricity on an hourly basis, they have little or no incentive to adjust their demand to supply-side conditions.

This is fundamentally a retail issue. Flat electricity prices encourage customers to over-consumer in hours when electricity rates, prices, are actually higher than their average rates, and they tend to under-consume in hours when the cost of producing electricity is lower than their average rates.

As a result, electricity costs may be higher than they otherwise would be, and we sometimes have to run high-cost generators for a few hours in order to meet the non-responsive -- the non-price-responsive demands of consumers, because we don't really expose them to hourly prices.

For policymakers, sort of threshold questions are: What evidence is there out there that real-time pricing or critical-peak pricing, actually delivers demand response?

Another major barrier is the lack of advanced metering into sort of smaller customers. That's a major implementation issue.

And, at bottom, as I go around the country and talk about this issue -- and I've done it for the last three or four years in various jurisdictions -- the fundamental question is, do state public utility commissions have the political will and are they willing to take the heat to aggressively promote price-based demand response?

And I'll show you some evidence from folks that have tried and where we stand today in that area.

Several years ago, we conducted a survey of all of the optional RTP tariffs that existed in the U.S. We got about 90 percent of the utility program managers to respond.

This chart gives you a geographic overview of utilities in each state, those with real-time pricing as an optional tariff. There are about 43 distinct programs that responded to our survey. We interviewed program managers, and it was about 90 percent of the market, we think.

But you can see from this chart that these programs tend to be -- these activities -- these tariffs tend to be most popular in the Southeast, the Midwest, and the Mid-Atlantic regions. They are not offered by many utilities in the West or in New England.

In terms of the actual delivered demand response from these programs, around ten of the program managers actually could give us data on how customers responded when prices were high in their programs.

This chart lists the utilities. I'm not sure everybody can read that, given the size of the font, but what you can see from this is that prices for these utilities ranged from anywhere from about 30 cents a kilowatt hour to about $6 a kilowatt hour at Georgia Power for one high-price event.

The aggregate load reductions are relatively modest. They are less than one percent or around one percent of system peak for most of the utilities, except for

Georgia Power, which got up to four or five percent for a couple of high-price events.

What underlies these optional tariffs, fundamentally, is that you've got to get customers to enroll in the programs, you've got to market them aggressively, and customers must respond significantly, in aggregate, when prices are high.

The evidence to date is rather mixed. There are three or four programs that account for 80 percent of the customers enrolled in the United States -- Georgia Power, Duke, TVA, an they've had a fair amount of success, both in enrolling customers, getting market penetration, and actually getting them to respond.

The experience of other utilities around the country is much more mixed. In a lot of cases, these programs have just been pilots; they haven't been aggressively marketed; there's a lot more that could be done.

This is a chart from a recent study that we did. In those states that have established retail competition, they have to deal with the issue of default service.

We looked at eight states that had considered or implemented real-time pricing as a default tariff. Now, this figure shows the amount of load exposed to hourly spot market prices through the utility's RTP rate and hourly prices that come from competitive suppliers who have got contracts with customers.

Now, what you can see is that we're showing in each of these states, that there's a certain amount of the load that's exposed to hourly prices. These are large customers, ranging in size from 750 KW and above in New Jersey; 300 KW in Maryland, I believe; Niagara Mohawk is 2 megawatts and above, so they account for a certain part of the system peak.

And then you can see in this chart that roughly about anywhere from a third to a half of the load that could be exposed, has decided to face hourly prices. We view this as a rather encouraging phenomenon, and I think the real message of this chart is that when you look at default RTP, don't just look at the utility tariff and who is on that tariff, because the goal of these tariffs in most cases, is to encourage customers to switch to the competitive market, but look at the price offerings and the deals that customers are signing up for with retailers.

In order to do that, you've actually got to collect the data. We show error bars in this chart, because we went through a variety of efforts, talked to retailers, and estimate the range of what it might look like, if the amount of load is exposed. This is a real data problem area or issue.

For retail regulators, if you want think about demand response, you've got to have -- in your states they have retail competition, and you've got to think about how much load is exposed?

We've also done some detailed case studies of utility programs with a default service. This is work that we've done with Niagara Mohawk. We talked to 150 large customers that are above 202 megawatts. About half of them responded to our survey.

Basically, about half the customers report multiple barriers, and you can see them listed in this chart.

I'm only going to get to my second challenge, and the second one is improving incentive-based demand response programs. Load management programs that have been around for ten or 15 years, need to be adapted to new market structures or circumstances.

A lot of times these programs only have emergency triggers. It's not difficult to actually have them have dual triggers, in terms of high prices, as well.

But you need to rethink some of the program design features related to triggering events; you need to link payments to actual performance. A lot of the interruptible, curtailable programs, are not at all linked to actual performance.

You need to enhance monitoring and verification capabilities, to allow load management programs to participate in various types of wholesale markets -- capacity, reserves, ancillary services.

And a key issue to address is the fact that with the proliferation of market actors, competitive retailers, wires-only companies, no single entity has the incentive to pursue the full benefits of demand response, and that's a real institutional challenge that you need to overcome.

I'm not going to go through the slides about the different ISO programs, which summarize the benefits and costs.

This last area, the third area: I'll just talk for a minute about analysis and valuation. Right now, we have a pretty good handle on how to characterize direct load control impacts. There have been lots of studies that measure load impacts in these programs.

But the impacts from price-based demand response, which depend heavily on customer behavior, are really less well known. There are a number of studies that have tried to calculate the elasticity of demand, and there's been a lot of work done on it, but when you actually translate that work into the actual system impacts, hour-by-hour, there's a lot of work that needs to be done.

I've listed here, a couple of the challenges in estimating the net benefits of demand response. The first thing is, you've got to get people to report their costs. It's actually quite uneven around the country today.

Nobody reports their participant costs, just the utility or the ISO costs. The value of demand response is not currently reflected in standard benefit/cost tests that are used to evaluate energy efficiency programs in many retail jurisdictions.

The reliability benefits are valued differently by customers, and this makes -- so it's a challenge, when you think about what's the value of lost load to different customer segments? You've got to do some work around that area.

And the other benefits of demand response are somewhat difficult to quantify. There are other market benefits in terms of market mitigation, market price, putting pressure on market power and so on. Those are difficult to quantify. They are factors for some regulators, but you need to think about it.

The bottom line is, you need a more comprehensive evaluation framework to really value the benefits of demand response, and that's something that's going to have to be taken up by states and regions as they look at setting goals and targets.

With that, given that my time is up, I think I will stop. Thank you.

MR. KATHAN: Thank you Chuck; that was very informative. Why don't we go through and hear comments from each of the panelists, and, as I mentioned before, after we finish with the full set, then we'll open it up for Q&A.

So, our first panelist after Chuck is Rick Tempchin from EEI.

MR. TEMPCHIN: Thank you, Dave. Commissioners and members of the FERC Staff, I appreciate the opportunity to be here.

My name is Rick Tempchin, and I'm Director of Retail Distribution Policy at Edison Electric Institute.

I commend the Commission and the Staff for convening this workshop. It will be a useful opportunity to hear from various demand response experts. In the audience, I see many familiar faces, people who have dedicated their careers to demand issues, energy demand issues.

Demand response poses many challenging questions, and the electric utility industry appreciates the efforts that all of you have put in to providing input to the Commission.

EEI supports policies and programs that promote customer participation in demand response options, by encouraging customers to discover the value of demand response. We continue to agree with the Commission's statement in its 2002 working paper that demand response is essential in competitive markets to assure efficient interaction of supply and demand.

Our detailed comments are in the docket, and we've published several papers that are available on this issue, over the years. Today I'd like to briefly discuss three issues: First, the issue of treating demand response as a resource; second, the issue of subsidies for demand response; and, third, the issue of rising electricity prices.

First, regarding demand response as a resource, the Commission should revisit its definition of resource contribution. In the Notice, resource contribution is defined as potential peak reduction at time of system peak.

There are two reasons to revisit the definition: The first is that demand response should be viewed as a resource in the same way -- should not be viewed as a resource in the same way that supply resources are viewed, that is, demand response is not supply, and some policies that equate demand response with supply, are confusing and unproductive.

The second reason is that the definition appears to refer to an earlier time when electric utilities operated essentially as islands. They needed to secure resources to meet anticipated levels of demand, plus an adequate reserve margin.

However, today, with the advent of wholesale competition, the issue of resource adequacy has moved to the regional level. There is typically no need to set specific demand response targets, and doing so may actually be a constraint on regional flexibility.

The policies that are being contemplated for demand responses will, in today's market, need a revised framework that is sensitive to near-term operating reserves, system conditions, and wholesale cost of power at the time that resources are being utilized and where demand response offers the greatest locational advantage.

In the context of demand response, the term, "resource contribution," needs to be defined relative to some notion of low operating expenses, reduced reliability, or high economic costs of resources involved in providing power, with reference to some normal level.

In the context of resource planning, the system peak demand used to assess resource adequacy, is a forecast level that typically includes a range of uncertainty, then supply capacity availability is assessed relative to forecast peak.

Demand response resources may be treated as adjustments to the load forecast, as potential increments to supply capacity to meet the unadjusted peak load forecast.

Increasingly, however, the greatest value of demand response may not necessarily occur at the time of system peak.

The second issue is the issue of subsidies. Subsidies relate to the Commission's question on resource contribution, demand response potential, and equitable treatment of demand response.

For demand response to succeed, it must be marked-based, cost-effective, and promote economically-efficient pricing. Subsidies for demand response should not be used, except for certain pilot or research programs. Some temporary subsidies may be appropriate, that's clear, however, subsidized increases in demand response, come at the expense of increased costs to non-participants, increased overall market costs, wealth transfers between market participants, and decreased market efficiency.

Thus, subsidies do not promote and maintain full competitive markets, instead, increased market instability.

Demand response should not receive preferential treatment, rather, it should stand on equal footing with supply-side and transmission resources.

However, this does not mean that consumers should simply be paid for not consuming power. Reduction in demand is not an increase in supply.

Any payment to a customer for demand reduction, should never exceed the wholesale price, minus the retail price that the customers would have otherwise paid to own the power. Any payment above this level, would be a subsidy, that is, a non-market payment that has to be recovered through a tax or charge on all customers.

If customers are to be paid to reduce their demand, as opposed to simply relying on their decision to buy less when prices rise, then they must own it before they can sell it back. This allows customers to reap rewards in exchange for taking on some risk. There's no reason to distort the market by paying artificial subsidies.

Load reductions during occasional periods of high wholesale costs, produce cost-saving net benefits to demand response customers and their load-serving entities without subsidies.

Lastly, I would like to mention the issue of rising electricity prices. Fuel costs are increasing and investments in generation, transmission, distribution, demand response, and conservation, are obviously needed.

At the same time, rate freezes are ending. Rate cases will seek billions of dollars in revenues to cover these investments. As a result, consumers will face increasing electricity bills, as utilities raise rates to reflect their costs.

Without a doubt, demand response is critically needed. However, I urge you all to resist the temptation to oversell demand response. Let's not try to make demand response a political bargaining chip; rather, let's work together to create options that customers will embrace, options that rely on natural market-based incentives for load-serving entities.

These market-based incentives, coupled with regulatory incentives to improve economic efficiency in retail electricity pricing, are enough to increase demand response.

Customers are smart and will be watching every dime. Our only choice is to create opportunities to work with customers and to avoid unproductive arguments. Thank you for your time, and I look forward to our discussion.

MR. KATHAN: Thank you, Rick. The next panelist is Jay Morrison from the National Rural Electric Cooperative Association. Jay?

MR. MORRISON: Good morning. Thank you very much for the opportunity to come in and share with you, the view of NRECA and electric cooperatives on demand response this morning.

Just a very short background: Electric cooperatives are consumer-owned, consumer-governed, not-for-profit, load-serving entities. It's a mouthful, but what it comes down to is, our goal is to find ways to provide our consumers with safe, reliable, high-quality power at the lowest possible cost.

And because of that, electric cooperatives are very strong supporters of demand response. Nationwide, a recent survey shows cooperatives can control approximately six percent of their peak load through demand response programs. That's about double the number we just got from Charles for all utilities nationwide.

Now, why do we have this much demand response? It's because it's a critical cost and risk management tool for cooperatives as load-serving entities.

Demand response allows us to shape our load, reduce our contractual demand costs, and reduce our risks in the wholesale markets. That means that we can provide wholesale power to our consumers at the retail level, under stable and affordable electric rates.

Now, even though we are very strong supporters of demand response, we do want to sound a bit of a cautionary note. We hope that the Commission will not allow its enthusiasm for demand response to distract it from the reason why we're involved in this exercise in the first place, which is to lower costs and improve service for electric consumers.

Now, what does this mean? A couple of different things: First of all, demand response programs should be subjected to the same due diligence as any other investment in infrastructure.

The fact that demand response has not achieved 100 percent penetration is not just because of regulatory or industry barriers, but because it is not necessarily a good investment for every utility, or a good decision for every consumer.

Now, Congress recognized that in the recent Energy Policy Act. It required states for utilities whose rates they regulate, and non-state rate-regulated utilities to decide for themselves, whether or not to adopt time-of-use rates and advanced metering.

Congress recognized that this decision needs to be a local decision, because the value is local. Just to let the Commission know, NRECA is taking that Energy Policy Act directive very seriously. Even though only about 200 out of our 930 members fall above the statutory threshold, we are encouraging all of our members to consider the federal standards, including demand response, and we will be holding day-and-a-half seminars around the country to help educate our members about how to look at these issues, including demand response.

Second cautionary note: We're hoping that the Commission will not permit bypass of load-serving entity demand response programs. What does that mean?

That means that retail consumers should not be permitted to participate directly in wholesale markets, if they're still being served by a traditional LSE, because the LSE needs that customer's participation in traditional programs to allow it to provide low-cost service to all of its consumers.

Allowing bypass, undermines the ability of the traditional entities to manage risks for all of their consumers. If a consumer is located in a state with retail competition, has a competitive supplier, then wonderful; that consumer should be participating in the wholesale market to protect their own interests.

But if that consumer is, by choice or by state law, still participating under a traditional utility, the traditional utility needs to have the demand response tools inhouse.

Third warning -- am I running out of time here? One minute, okay.

This is sort of a broad statement here that NRECA uses over and over again in a lot of subjects, and that is that markets should be designed to serve consumers. Consumers shouldn't be required to change their expectations in order to make markets work.

I was at a conference the other day, and a financial analyst made the comment in support of demand response, that if you smack consumers, they learn and they'll start to use less power. Well, we haven't had one member tell us that their consumers are asking to be smacked.

Finally, demand response is not a substitute for much needed investment in transmission. Although demand response is a very good tool for what it does, it is not going to allow utilities to get to the range of options we were hoping to get from wholesale markets -- options for preserving reliability and options for obtaining low-cost power for our consumers.

That's why we're very pleased to see that the Commission is doing as much work as it's doing in order to find ways to get transmission planned and built to serve consumers' needs. Thank you very much.

MR. KATHAN: Thank you. Next will be John Kelly from the American Public Power Association. John?

MR. KELLY: Good morning. My name is John Kelly and I'm the Director of Economics and Research at APPA. We thank the Commission for the opportunity to appear here today to present our views on demand response, especially in regard to time-of-use pricing.

We probably agree, in general, with most of those who support demand response and time-of-use pricing programs. Almost a decade ago, a special task force of APPA members recommended that the Association promote the increased use of demand response by adopting marginal cost pricing principles in the design of electric rates.

Such principles provide the economic rationale for demand response and for time-of-use pricing, in particular. Since then, the Association has developed manuals, educational courses, and other materials to inform our members about such principles.

Next month, APPA will be offering a course, the first of its kind in the country -- or among the first of its kind in the country -- devoted exclusively to the design and implementation of time-of-use pricing.

While we probably agree, in principle, with the views of many of those who advocate demand response programs, there are a few particular issues which require some clarification and more emphasis. They include: The appropriate definition and rationale for demand response; improved capacity utilization as a major benefit of demand response; the relationship between market prices and costs, and the degree of precision necessary to garner the benefits of time-of-use pricing.

Demand response has been defined in several ways, and one popular definition is that it provides electricity consumers in both retail and wholesale electricity markets with a choice whereby they can respond to dynamic or time-based price signals or other types of incentives by reducing or shifting usage, particularly during peak times, such that demand modifications can address issues such as pricing, reliability, emergency response, infrastructure planning, operation, and deferral.

While this definition does a good job summarizing the general characteristics of demand response programs, it fails to adequately describe the central rationale for such programs.

These programs simply attempt to have consumers respond to the real cost of electricity service. These costs vary by time of use, and traditional costing and pricing practices fail to reflect the time-varying costs of electricity, consequently, a need for demand response programs is created. Prices

Prices based on traditional rate design, typically do not reflect the economic costs to society. The economic costs may be 20 cents or more at particular times, and customers may pay a price of only six or seven cents; at other times, the economic costs may be two or three cents and customers are paying six or seven cents.

The heart of the matter is to have customers choose their pattern of consumption, based on the time-varying real cost of electricity. The disconnect between prices and real economic costs, not only causes too much generating capacity to be built; it causes significant under-utilization of the existing stock of generating resources.

There are opportunities to increase the capacity factors of the nation's stock of generating plants from their historical low levels of 50 to 55 percent, by designing and implementing rate structures that track costs and spread relatively more kilowatt hours, the supply over relatively fewer kilowatts of capacity.

There's nothing new under the sun in all of this. These are basic economic facts of life that leading economists advocated more than 90 years ago. Time-of-use pricing in the form of marginal cost pricing, would significantly improve capacity factors, lower costs, and, prices, in turn.

Posing the rationale for demand response programs, especially time-of-use pricing programs, more directly and concretely, simply as a matter of matching prices to the real cost of electricity, would make it easier for consumers to understand and accept.

But, the word, "cost," is rarely mentioned and hard to find in most popular discussions of demand response. It is simply assumed that the time-of-use prices customers are charged, should reflect market prices, but market prices may not reflect the economic cost to society of producing and consuming another kilowatt hour of electricity.

The emphasis on market prices and the short shrift given to the question of whether market prices reflect economic costs, is a legitimate one. To the extent that retail electricity prices are tied to market prices, consumers need assurance that those market prices reflect the economic cost of service and nothing more.

Finally, we are concerned that some of the time-of-use pricing proposals may be more complicated and costly than necessary, and will, consequently, engender consumer resistance to time-of-use pricing, in general. For example, some consumers are concerned that real-time pricing programs will make them slaves to meter-watching, 8760 hours a year.

Utilities are concerned about the associated costs of metering and billing for these programs. RTP programs may be an example of the best being the enemy of the good.

Such programs are appropriate for some customers, but likely not for all. Although, in principle, each kilowatt produced during the year is a different economic product, as a practical matter, there are clusters for which prices are similar, so, rather than starting to design a time-of-use pricing program or a real-time pricing program based on 8760 hours, a more practical and useful approach may be to start with an existing time-of-use program and to expand and refine it to 12 or 16 periods in a year, and this would garner probably most of the benefits of time-of-use pricing.

MR. KATHAN: Could you wrap it up?

MR. KELLY: Yes.

The points made here have also been discussed in the Association's December 19th comments. We highlight them here today, simply to emphasize them a bit more. Thank you.

MR. KATHAN: Thank you. The next panelist is Alison Silverstein. Welcome back.

MS. SILVERSTEIN: Thank you; it's surreal to be here.

(Laughter.)

MR. KATHAN: Alison is an expert on reliability and demand issues, and we'd like to hear her comments today.

MS. SILVERSTEIN: Thank you. I am here representing no one other than my own ordinary self.

I believe demand response is essential for resource portfolios, for risk management, for operational reliability, and for customer empowerment for good, true, market operations.

I also believe that some things like wholesale electric competition, are giving up customer's information about the true cost of electricity and giving them also the power to act on it, are right and worth doing, no matter what the cost/benefit tests come out to be.

But, yes, there are barriers, and, yes, demand response needs to be better. I'm going to focus on three particular issues today:

The first is that when I look around the country at most of the demand response programs out there, the goals of the programs are unclear. Nobody seems to have thought through, except in very few cases, why, specifically, are you doing this?

The second is this: Who is the customer you're designing for? What is the job you're trying to fill when you do this?

And the third is that when you look around, you see way too much whining and way too little action.

With respect to goals, except for emergency demand response programs, most demand response programs don't have a clearly articulated purpose, other than to do DR for the sake of doing DR, or to do another damn pilot, which pretty much guarantees that you won't get a great result, because you haven't defined what success looks like.

I think you need to articulate a couple of very clear and specific goals for any demand program you want to undertake, and I think this should be a requirement for every regulator who wants to require a demand response program, or every utility or ISO that wants to put one into the field.

I think those goals are: Resource adequacy; operational reliability and flexibility; portfolio diversity; price moderation and market power mitigation; and/or customer empowerment, which is probably the only thing which is sufficiently Zen that it's difficult to articulate your goal clearly.

But in each of those cases, you need to pick a single goal and you need to design your program to nail that goal, and you need to know what it means to have succeeded at that. This requires -- when you have articulated that goal effectively, you can do program design, you can do participant recruiting, you can do benefits calculation, program-building, and operation, far easier, with a good, specific, goal focus, than you can with just some generic I'm-going-to-do-demand-response effort.

Clayton Christensen, the Harvard Professor, said that customers don't buy attributes and benefits, they buy a product to do a very specific job.

Most of the demand response programs, with a few rare exceptions, don't ask who is the customer, and they don't say what's the job that she needs done and that I want to fulfill?

We heard yesterday that Texas was one of the places that customers view as having one of the most successful sets of demand response programs, and I'll tell you why I think that is.

In Texas, they don't call it demand response; they say load acting as a resource. That's a hint. They have a goal, they have a very specific purpose, and they've designed all of their programs to nail that goal.

It's like Colonel Sanders, they're doing one thing and they're doing it well, and they're not trying to be all things to all people, or all features to all program designers.

My next issue is, who is the customer? When you actually listen to people talking about demand response, the job that they are trying to fill, their customer they're really trying to make happy, is the utility and its needs or the ISO and its needs, or the regulator and what the regulators needs that are being imposed upon all those other players, but they very rarely talk about the end-use customer whose behavior they're actually trying to affect.

I think you need to be very much specific about who is the customer, what is the job you need filled, what is your retail customer who's ultimately going to have to get that job done for you, what are her needs, what are her jobs, and how can demand response serve them?

Then when you look at it in that way, you find that demand response programs are still too complicated for most customers to be happy to participate in. So, if you go to what are the retail customers' jobs and needs and how do we make it work for her, in order to roll it back up to get something that ISO or utility needs to meet my goal of market power mitigation or resource adequacy or operational reliability, you get a much cleaner result.

My third concern is that there is too much whining and too little action. Here's a sample of some of the whining that you have either already heard or will hear throughout the day: There are too few customers responding; customers need more education to do this; there are too few vendors offering; the subsidies are too high or too low, depending on which side of the fence you're on; there aren't enough meters installed or they're the wrong meters; there's no system to plan holistically; you can't get all the benefits quantified and monetized in single stream, so that someone will write me a check big enough to cover my program expenses.

These are all of the if-only's, and there's another -- two more -- one is impatience. Everybody wants the results immediately. You forget that it took a century to get the grid we've got today, and it took 25 years or more to get conservation load management at the level we have today, so, gee, why do you think we should get demand response in place in five years, other than the classic peak-load management kinds of stuff going on?

So, impatience isn't working. We need to recognize that this requires the same kind of commitment for long-term growth and program-building investment that we've allowed to the supply side and to classic conservation types of programs.

The second thing that I see as a classic barrier, is constant programmatic tweaking and the commitment to everybody that they have to invent their own. We are suffering the death of a thousand pilots, and I think that's a mistake.

So, my view is, things aren't perfect yet. Yes, there's problems, but let's deal with the hand you've been dealt.

There's a lot of demand response that we know works today. There's a lot of enabling technologies that we know work today. There are a lot of customers who are willing to respond to prices, if you will only give them the chance and trust them.

And there are a lot of very clear jobs that need to be done, that demand response can perform for you, whether you're the end-use customer or the ISO or the utility.

I think we need to do a little less analyzing and wheel-spinning and a lot more of define your goals and start getting the job done. Thank you.

MR. KATHAN: Thank you, Alison. Our last panelist is Tom Kerry, representing the Environmental Protection Agency.

MR. KERR: Good morning. Thank you for inviting me to make some brief remarks today on behalf of the U.S. Environmental Protection Agency.

The EPA supports demand response resources as a strategy for providing significant, cost-effective emissions reductions by controlling load growth served by fossil-fuel fired power generators, as well as associated transmission and distribution losses.

According to EPA's latest inventories, the electricity generation sector is the largest contributor to U.S. greenhouse gas emissions, contributing a third of U.S. carbon dioxide emissions.

Demand response and other demand-side resources can make an important contribution to reducing these impacts.

In addition to environmental benefits, demand-side resources provide reliability, security, and field diversity benefits.

For over 15 years, EPA and the U.S. Department of Energy have actively supported demand-side resources through the Energy Star program. Working with commercial, residential, and industrial energy users, Energy Star has helped control electricity load growth, providing four percent of U.S. energy consumption through energy efficiency.

While these are strong results, there remains a tremendous untapped potential in the U.S. for additional cost-effective demand-side resources, including demand response and energy efficiency.

This is because, while these investments are generally reliable, today's markets do not treat demand-side resources similar to supply. Markets need the right policies to allow for full utilization of cost-effective demand-side resources.

Policies that are important include ones that value demand-side resources equally with other resources in the resource planning process, as well, ones that quantify the other benefits of demand response, including reliability enhancement and environmental benefits, among others.

Also, investors, including utilities, need policies that send clear market signals that demand-side resources investments do not cause them to lose revenue.

To address these barriers, EPA, together with the Department of Energy and leading electric and gas utilities and state utility policymakers, launched the Energy Efficiency Action Plan last month. The Action Plan effort is designed to bring national focus to key policies and solutions that allow demand-side resources to compete equally with traditional resources.

The demand response efforts envisioned by the Commission's proposed demand response survey and this Technical Conference, are complementary to EPA's ongoing energy efficiency work. If designed properly, EPA believes that time-based rate programs can provide incentives for targeted energy efficiency investments to provide resources that effective shave the system peak.

However, additional study and analysis needs to be done to assess the effectiveness of these programs. That is where the Commission's proposed survey comes in.

The draft survey requests potential peak reductions in megawatts from existing demand response programs. To better assess program effectiveness, EPA believes that the Commission should request actual data for both peak reduction in terms of megawatts, and changes in total annual electricity consumption in terms of megawatt hours.

Similarly, it would be helpful if the time-based rate programs section of the survey included requests for actual and potential megawatt and megawatt-hour data.

This data would be extremely useful in shedding some light on the actual impacts that demand response programs have on electricity consumption. It would also help policymakers and utilities assess the performance of existing programs that have attempted to combine energy efficiency and demand response.

Finally, it would help utility and state decisionmakers that are looking to understand the environmental impacts of their demand response efforts.

We continue to hear that a key barrier is the lack of data about demand response programs, and FERC can act to help fill this gap.

Thank you for the opportunity to make these remarks, and we look forward to working with the Commission on this and other efforts that spur greater investment in demand-side resources.

MR. KATHAN: Well, thank you very much for those comments. I'm going to open up the questions, first, to the Commissioners, if they have any questions, and then questions from the Staff.

COMMISSIONER BROWNELL: Dr. Goldman, help me identify what we can do about the data issue. It does seem to be a recurring theme.

What can we do, what can states do to get a better mandate for collecting of data, so that we kind of can get the information we need to make decisions?

I'm fascinated by the Georgia Power participation numbers. Who are those customers?

MR. GOLDMAN: Second question first, in Georgia Power, I believe their real-time pricing program is available to any customer over 200 KW, peak demand, and Georgia Power has, I think, something like 60- or 70-percent market penetration.

Eighty percent of the industrial load is on their current program. We wrote a whole paper, and others have written papers about Georgia Power's program.

It's a relatively unique program, and the rates are very attractive, compared to the underlying retail rate, and it's been hard for other utilities to duplicate that kind of design, but that's another question.

COMMISSIONER BROWNELL: No competitive markets, also helps.

MR. GOLDMAN: Yes, it's a very different kind of program.

COMMISSIONER BROWNELL: It's a different part of the country.

MR. GOLDMAN: The one thing that's clear, is that Georgia Power's senior management has made a very high-level commitment to the program. They market it aggressively. They've been doing it for ten or 15 years.

They have a very strong commitment to the program, and it's part of their competition package on how they compete for new load in the area. They got strong support from the regulatory commission in the state.

As to the first question about data, there are three or four areas: On the cost side, FERC could actually get ISOs to report their program costs in a consistent fashion. Right now, it's not done quite consistently across ISOs.

FERC could explore the issue of participant costs, other than what the ISO incurs. States do that routinely. Energy efficiency is another issue.

From my perspective, one of the bigger issues is trying to get retail suppliers in states that have retail competition, to share some information about the types of contracts customers are signing, in aggregate, not revealing individual customer data. But a key policy question is, are customers facing real-time prices? Would they even want to be exposed to them?

Some ISOs have tried to collect this information and have had difficulty. There's nobody requiring them to do it, but if you want to move in those states that have retail competition, if you want to move toward having customers being exposed to prices, you have to understand what's happening in the market, and, right now, we have very little information about what's happening among retailers in this area.

Then the third issue is, in the ISO programs, in your economic demand response programs, you could develop consistent definitions of what you think a customer's curtailable load is. Right now, in emergency programs, ISOs typically require -- people sign a commitment, they say I'm going to curtail one 500 KW out of a two megawatt load.

The ISO system planners then have some idea of load to expect when an emergency arises. But in economic demand response programs, oftentimes the customer just puts in their entire peak demand. There's no systematic definitions that are used in most ISO economic DR programs,

So we have these very large enrollments in these programs, 1500 megawatts at PJM; 300 megawatts in New York, and you get ten megawatts peak in one day. How do you account for that?

Partly, it's the prices, but, partly, it's the way that you're actually thinking about what the customer would actually do. Those are simple things that you could do to get your arms closer around the problem.

COMMISSIONER BROWNELL: Thank you. Mr. Tempchin, you brought up the issue of subsidies. That makes me confused.

I'm not sure if you have some of the goals and the metrics that Alison talked about. You're necessarily subsidizing. You may be paying for something that you want to achieve in the marketplace, but maybe anybody could comment on when is a subsidy not a subsidy? What would satisfy your concerns in that regard?

It is one of those barriers that when we don't like something, it's a subsidy; when we like it, it's not. I don't have the answer, but I think we need to get there, and maybe it's a question of adequate goals and metrics.

MR. TEMPCHIN: Thanks. The idea of subsidies is a tough one, and perhaps it should be defined on a local basis.

But, in general, if rates go up for all customers as a result of the program, we consider that a subsidy.

MR. GOLDMAN: So new generation is a subsidy, if rates go up?

(Laughter.)

MR. GOLDMAN: Is that your definition?

MS. SILVERSTEIN: A ratepayer's definition, yes.

MR. TEMPCHIN: And this gets to the issue of reduction in demand is not generation, so we could have apples and oranges here. This is at the core of the debate.

There should be enough value to individual customers to participate. That's the challenge, is to look for that value and have the programs pay for themselves.

COMMISSIONER BROWNELL: Any other comments?

MS. SILVERSTEIN: It was too easy, I couldn't pass. Thank you.

(Laughter.)

COMMISSIONER KELLY: Chuck, your issues, are they in a hierarchical order, or your challenges, if you will? If you were making policy, if you were the policy Czar, which issues would you tackle first?

MR. GOLDMAN: I tried to group the issues. They are in somewhat hierarchical order for the policymakers, but they are somewhat grouped around who can do what. In other words, price-based demand response, fundamentally, is sort of a retail issue; incentive-based demand response is fundamentally a FERC and state issue.

Strengthening analysis and valuation is something that both state and federal policymakers are going to need, if they want to have confidence and want to be able to make comparisons about these sorts of things. It's sort of the underlying framework.

But, you know, the technologies have to do with customers, fundamentally, and incentives or subsidies or research R&D, and resource planning really is addressed to load-serving entities and policymakers who have to think about how do we capture the long-term value of insurance, because a lot of demand response is sort of a form of insurance.

Nobody want to pay for insurance, but you have to get auto insurance, you have to be sure that your markets reflect and capture some of that value.

So, they are in rough hierarchical order, but it's also about who can do what.

COMMISSIONER KELLY: Then let's talk about what FERC can do, since we're here at FERC today. In the wholesale market arena, particularly in the organized markets, I hear regularly that the way the ISOs are organized, and, given the stakeholder process, there are too few advocates that process works against establishing an effective demand response program. Do you have an opinion on that, or what kind of process would you use within an ISO to establish an effective and cost-effective demand response program?

MR. GOLDMAN: I think that a number of ISOs have established pretty effective demand response programs. It's somewhat uneven across ISOs, depending on their market structure and design and their level of maturity.

I think what FERC can do, is provide pay attention to the details. So far, you've provided excellent high-level policy guidance in support of this. You've made it very clear that you want this stuff in all the markets, you want demand response integrated into markets in sort of a normal fashion.

But you need to empower your Staff to interact more closely with ISOs about the details, because, unfortunately, in this stuff, the devil is in the details, so it's not enough to have just high-level policy pronouncements; you've actually got to keep an eye on the details and sort of do comparative assessments, do benchmarking, ask questions about the numbers, think about the methods that are being used, ask hard questions about why it's not happening in certain markets in certain areas, and allow your Staff and the Commission, the flexibility to think about, yes, one size doesn't fit all.

COMMISSIONER KELLY: Alison raised that, talking about the various potential goals of demand response, and, Alison, I think, advocated focusing primarily on one of them. Yes, Alison?

MS. SILVERSTEIN: If I may, you can't design one demand response program and expect it to perform all those goals. I think you need to say, I need Goals A, B, and C, and I'm going to design particular programs to serve resource adequacy and particular programs to serve operational flexibility and particular programs to serve market power mitigation, but I'm not going to expect one demand response program to solve all three goals for me at once.

It was more of a specific program design or indication to only do one.

COMMISSIONER KELLY: That's helpful. So, Chuck, would you take those goals, and if you took Alison's framework, how would you decide which ones to focus on? Is there one global best goal, or does it depend on the situation in each region? How would you choose them?

MR. GOLDMAN: I actually agree with the way that FERC has framed it. I think the notion that integrating demand response into existing wholesale markets, that is, administered by ISOs, is a reasonable way of conceptualizing how you should think about this activity.

Then, once you do that within each particular market, you'll figure out whether or not and how the program or activity should look.

I would point out that my own view is -- and this is maybe an area where I agree with Rick -- the whole policy thrust of FERC and others is to integrate demand into the wholesale markets. One of the things we're ultimately going to learn, is that demand isn't supply and that the best way to tap this resource, might be to think about different types of products, appropriately valued.

Right now, the thrust of most of our policies at the wholesale level, is, put the demand side into the box we're creating for the market, but, ultimately, that creativity is going to have to happen by load-serving entities that try to take ISO platform programs and market them to customers in a very disaggregated fashion.

I think we should be open to the idea of trying to value the kind of products that customers really want to offer. It may not be just one size fits all.

COMMISSIONER KELLY: Thanks. Alison, in your review of ISO markets around the country, do you have particular, or would you give us your opinion on some of the best? You can include Texas in that.

(Laughter.)

MS. SILVERSTEIN: I have not conducted an extensive review, so much as I keep bumping into all of this stuff again and again and again, so I'm not going to tell you that I'm an expert, nor that I have done an exhaustive study.

What I can tell you, is that there are some places where this stuff is clearly working. It's because there have been commitments to a clear and consistent set of goals and programs for a long time.

Texas exemplifies that, as does New England's emergency demand response programs and New York's as well. They have been doing this for a long time. They know how to make it work.

California talks a great game, but they have yet to deliver a consistent set of demand response, other than the California water pumping program.

So --

COMMISSIONER KELLY: In Texas and New England, how did the stakeholder process work; do you know?

MS. SILVERSTEIN: You'll have them up here later, but they converted a bunch of legacy programs and sort of rolled them up as they were building their markets. So they didn't say, hey, kids, let's do demand response, starting now, and we're going to lock people in a room until we figure out how to make it work.

They said, let's start with what we've got, and let's make it clear and better and keep it going. So, yes, there has been tweaking, but it's been for a purpose and to make things work.

And I applaud the goals of PJM in terms of wanting demand to a clear participant in the market. I think that's a wonderful thing, and I agree with it completely.

I think there's a long way between talking it and making it happen. I hope they do it as quickly as possible.

I want to -- is that enough of an answer that I can switch to go back to Commissioner Brownell's question about subsidies? I've been thinking about it.

COMMISSIONER KELLY: Sure.

COMMISSIONER BROWNELL: I knew you couldn't resist.

(Laughter.)

MS. SILVERSTEIN: I think that part of the issue about subsidies is that one man's meat is another man's poison. A lot of what he might view as a subsidy, I view as an intertemporal investment, or as an investment in something.

If I am buying insurance today -- I'm a sucker; I've been buying flood insurance at $310 a year for -- well, since I moved to Texas, which was 11 or 12 years ago -- because there was a flood down the street, and I looked at the cost of the people down the street of buying a new house, and I said, flood insurance looks pretty darn cheap.

I don't know. I know what the consequences of losing that investment are, but since I'm clearly getting very little value over the short term in this investment, I'm making an investment because there's something that I value.

Everybody else says, you're a sucker to buy flood insurance; it's a subsidy to whatever it is, you know. Maybe I bought somebody a square foot in New Orleans, who is a Katrina victim, with my flood insurance payments over all these years, but the fact is, I am buying something that I value with that investment, and I'm investing in the long term by making it every single year.

It seems to me that subsidies, when he says that's a subsidy because I'm not benefitting from you paying him, this payment to make demand response happen, the reason that we're making him pay for demand response, and me and everyone else, is because there are things that we value, like protection against floods, that we agree are desirable, necessary, and beneficial.

But there's not a really easy way to make it so that everybody is benefitting from it, like from resource diversity or from grid reliability. It's the classic externality problem.

You can't nail one person as the sole beneficiary, so you spread it across everyone, and if you don't want to pay for that, you call it a subsidy, and you say that it's unfair. But if you do think that long-term benefit is there, you say, I value that long-term benefit and I'm willing to do the, quote, subsidy, in order to achieve it for the long term.

I'm sure you'll find no professional economist who agrees with anything I've just said, but that's okay.

(Laughter.)

COMMISSIONER BROWNELL: Making it all the more valuable.

(Laughter.)

COMMISSIONER KELLY: Chuck, if I could ask you a followup on Alison's answer, are there any lessons, good lessons that we can learn from what any of the ISOs have done to date, ISOs or RTOs have done to date in demand response?

MR. GOLDMAN: I think there are some wonderful lessons.

COMMISSIONER KELLY: That was a good response.

(Laughter.)

MR. GOLDMAN: My short summary: New York, the best example of integration between the state policymakers, the ISO, and the public benefits agency in delivering a package of programs to customers, the best example of cooperation and harmonization of retail tariffs and underlying policy goals.

ISO New England is a really good example of how the ISO in the last couple of years, has listened to a broad stakeholder process called the New England Demand Response Initiative, and taken to heart, some of the recommendations that were sort of a consensus. They staffed up their program and basically tried to deal with some very difficult issues on sort of a locational basis.

PJM, they're huge, and what PJM does, is just incredibly significant, and they should be credited with breaking out of the box in terms of thinking about demand response as a spinning reserve resource, and, recently, for thinking about forward energy reserve markets in that proposal.

There's a lot of innovative thinking going on at PJM, again, in a difficult stakeholder environment.

All of these ISOs would be aided by continued support from FERC. You sometimes need the carrot and you sometimes need the stick, but the ISOs sometimes need help from you to deal with their stakeholder process, because they maybe want to do the right thing, and you're in charge of thinking about that longer-term public interest.

COMMISSIONER KELLY: Thanks. Any other participants in the panel who want to comment on particular ISO- or RTO-based programs that you're familiar with, that you love or hate?

(No response.)

MR. KATHAN: I have a couple of questions. I want to follow up with what John was talking about with regard to the need to set the right price, and wanted to hear from the whole panel's views on who do you we move to having a more price-responsive demand.

Are there barriers to that? What are the actual action items to be taken in regions or states, or perhaps by us, in order to ensure that customers start seeing what is the true value of consumption during various time periods? So I open it up to any panelist who wants to comment on issues of time-based rates.

MR. KELLY: Just to follow up or emphasize, the primary things are education and the point that Chuck made, the political will to do it. You've had 70, 80, almost 100 years of fully-allocated cost ratemaking, and to change from that, where customers are comfortable with it, however, creates significant economic inefficiencies that actually increases their rates, rather than lowers them in terms of the capacity factor. So, that's education and the political will.

Economists, it seems, should probably spend more of their time on these basic issues of the inefficiency of the price structures, or maybe they haven't spent enough time educating regulators on the importance of this.

MR. MORRISON: Thank you, David. A couple of points, if I may: First of all, while time-based rates are valuable for certain utilities, for certain customers -- and there are a number of cooperatives out there that have time-based rate programs -- percentages are mentioned in the comments.

I do want to make sure that we don't overemphasize the need for time-based rate programs. I was surprised, frankly, to hear from Dr. Goldman, that the results are, at best, five percent, but generally around one percent through direct load control, through interruptible contracts, through share-the-value or share-the-savings programs.

Many load-serving entities get far better results than that, without having to go through the political upheaval of shifting the entire rate structure. So, we need to realize that it's not just giving the ultimate consumer a rate that causes them to react, but you give the load-serving entity a market to respond to, and they will find a number of different tools, including time-based rates, to get the response they need to protect all of the customers in the market.

The market is getting a lot of demand response that the market doesn't really see, because it's happening within the load-serving entities. I just want the Commission to be aware of that.

MR. TEMPCHIN: Dave, I think what we'll see as prices go up, is that customers will work with their utilities, they'll complain, and options will be developed.

Commissions and utilities will come under a lot of pressure to come up with options, and they will demand creative options and will respond.

And I think that's what we'll see, we'll see the market responding in that way, and with all the pilot programs that are out there, that have provided all this good information, we'll have the resources to get creative.

MS. SILVERSTEIN: I think what Rick just said is absolutely correct, in theory, but the problem is two things: One of them is that there are still way too many rate caps out there and rate freezes that will prevent any meaningful responses, because, if you don't have to either raise or lower your rates, all you have to do is stall your customers long enough to have the immediate crisis that is causing them to complain, shut up.

And you can do that with a lot of small pilot programs. You can kill a whole lot of time without ever actually substantively solving the problems.

The second thing is that as long as we live with the classic utility revenue requirement and the necessity to keep the utility whole, all you're doing is shifting around the jello within a lumpy pot, and this guy gets a little less, but that means that guy gets a little more.

So until we actually rethink the balance of risk and revenue commitments and the nature of the utility's obligation to serve, relative to the ratepayer's obligation to keep the utility whole for its obligation to serve, you're always going to have -- I don't care what terms you're taking your electricity on -- you're still going to have to pay me a certain amount of money. It's just a question of how much you're going to pay for service at 4:00 in the afternoon in August, as opposed to 4:00 on Saturday in January.

I think that, yes, in principle, utilities and regulators want to react, to give customers better stuff, and to keep them quiet, but, in fact, there are a lot of ways they can avoid doing so.

Moving to a completely different topic on the issue of prices and are they accurate, it seems to me, you also need to look at the classic issue of what is the nature of the price and where does the value of electricity come from for the grid in a centralized, organized market, with spot prices, versus the value of the electricity in an integrated utility.

Where is that cost? What is the basis of the calculation of that cost information? Are you just going to use System Lambda, which is the marginal price that the utility claims that its dispatching arm -- well, System Lambda hides a multitude of sins that the utility is shoving into its dispatch staff, and doesn't necessarily give you a more valid -- it gives you a representation of what the utility's marginal cost of operation is, but that doesn't mean it's correct, although it is guiding the system's decisions, and maybe that's close enough.

At least with an organized market and LMP, you have a pretty good idea of what the true cost of that resource is at any moment in time.

The question is, how much you are going to be truthful to that? Are you going to do locational pricing requirements, translate the locational value, as well as the time value, all the way down to the retail customer, or are you going to gloss over that and start average-costing in your real-time prices, or something else?

The last thing is, not everything needs, as others have said, not every customer needs to be tortured by real-time prices, and not every customer needs to be seeing time-varying, whether it's every five minutes or every 15 or every hour.

A lot of customers just need a relatively blunt object, such as time of use and critical peak, so I don't want people to get too wigged out on, it's about real-time prices, because that's not necessary. Thank you.

MR. GOLDMAN: There is an important relationship between the organized markets and the development of time-based pricing, and I think FERC should take some credit for this. In our research of the eight states that have looked at real-time pricing as a default service, one of the critical factors was the fact that customers trusted either the real-time market prices or the day-ahead market prices that were coming out of the ISOs.

That dealt with lots of their kind of concerns, historically, about System Lambda and what was happening and that kind of stuff, and, so, again, predominantly time-based pricing is a retail issue, but at the wholesale level, one of the things that FERC can think about -- and the other ISOs that are out there -- think more systematically about the real-time markets that exist in those states.

It's been a big problem in California. One of the prime objections to moving to real-time pricing, by large customers, is the fact that there is no real-time market or day-ahead market that they trust in terms of the actual prices that come out of it.

It takes time for that kind of confidence to develop, but it's one of the ways in which you can link your wholesale policies with the development of retail activity.s

MR. KATHAN: Thank you. I had a question, which is a related question, which is now about -- there's been a lot of discussion about the fact that distribution companies do not have an incentive to participate, especially in the rate-restructured states.

What are the policies that should be done in order to help distribution companies, either stay whole or be interested in developing and/or supporting demand response? Rick, why don't you start?

MR. TEMPCHIN: Thanks, Dave. Sometime ago, we talked about demand-side management incentives for utilities to recover costs and account for lost revenues and a bonus on top of that.

I think what we'll see is some creative mechanisms along those same lines, different than the past, but related for the distribution companies, and also, like I said before, customers are going to demand these things. They are going to demand options, and utilities will respond.

MR. MORRISON: There's a couple of reasons why a utility would engage in demand response. The first is, as Rick just mentioned, accountability to the consumer, either directly, like the customer-owned utilities, or through a regulator for the investor-owned and some cooperatives.

If the customer expects you to and has the right to force you to provide them with the risk management and the cost management, then you're going to need to use this as a tool to do that risk management and cost management.

If the state has somehow broken that regulatory compact and the obligation to serve, that's a lot harder to do. But let's assume you've got a traditional LSE with an accountability to consumers.

That doesn't answer the question all by itself. The question then goes to, well, what does that utility's load profile look like? What does their customer base look like? What do their wholesale costs look like?

We have a fairly large member that has been asked by its consumers to look at demand response, but their load curve is pretty much flat. They run almost exclusively on coal, because they don't need peaking.

They can control their irrigation load, which keeps them with almost no peak. There's no economic benefit to them, at least for the next 20 years, to do demand response. It's very hard for them to justify it as an investment.

We have other members that have a lot of industrial loads that's capable of responding, or a lot of irrigation load that's capable of responding. They have very high demand charges in their wholesale contracts, or very high market exposure.

For them, they need to be doing demand response as a way of controlling the demand charges or the market exposure, and they have the resources within the cooperative in order to do that. So it's not just a matter of sort of setting up incentives; it's not just a matter of accountability; it's also what does this system look like? What do their costs look like? What do their consumers looks like.

MR. KATHAN: Thank you. Anyone else on the subject?

(No response.)

MR. KATHAN: Do any of the other members of the Staff want to ask any questions? We have time for about one.

MS. WHITE: I have a followon to David's question. Is it necessary to decouple the whole concept of the revenue coming from the amount of kilowatt hours you're getting paid, in order for utilities in a restructured world, to want to offer demand response?

MS. SILVERSTEIN: I don't think so. The problem is that if you want demand response to work in the short term, if you want it tomorrow, my life isn't long enough to wait for most utilities to get around to staggering through the decoupling.

I've done rate cases, and they're hell, even without something as radical as trying to decouple revenue, et cetera. I think what you want to do is just be very specific about here's what I need to accomplish, and, yes, it would be lovely if some utilities decoupled, but, in the near term, we really need this stuff, so I think you need to be very specific about your carrots, your sticks, and your sticks painted orange.

Not everybody needs to do this in the same way and for the same purposes. So, design incentives that are very specific.

If you want to do this for customer empowerment purposes and for market mitigation kinds of things, and to get true resource efficiencies, then what you want to do is mostly price-based programs. That means you need to pay for the meters.

You need to take the risk out, but you have to also define appropriate functionalities, so they're not buying crappy meters. You have to say, here's what a good meter looks like, and here's the money to make sure you get it.

Then step back and let them do that. That's a good, solid carrot. A stick painted orange is, the lights are going out unless you do this stuff, and I'm going to make you pay unless you do it, in terms of you will bear the consequences, you will bear the political heat, you will be customers -- in the following ways, so that is a pretty ugly stick right there, even if it's painted orange.

So, what you do is, you design your incentives very specifically around what do you want to accomplish? What kinds of technologies, what kinds of behaviors do you need, and is it fear or bribery that's the best way to get people there?

And you can't just say there are generic incentives, because there aren't.

MS. WHITE: Thank you.

MR. TEMPCHIN: Just a comment on decoupling: I don't think you need decoupling. It's an option. It's kind of a blunt instrument.

It shifts risk to customers; it increases prices in times of economic downturns. It might work in some places, under certain circumstances, but it's very limited.

MR. GOLDMAN: I was going to give an answer to the previous question. You talked about the disincentives that distribution utilities have in restructured markets, and I think there are sort of three issues to think about:

The first one is those distribution companies that have active load management programs, legacy load management programs that have been around. What's happening in a number of regions is that these programs are declining and eroding and sort of being mothballed.

So the key issue for the state regulators is to make sure that there's cost recovery for the utilities, if they want to continue those programs, if they still make economic sense.

The other issue is for the typical distribution utility, it might have had a curtailable, interruptible rate for large customers. That, again, varies by state and utility.

There, I think the challenge is to sort of transition those programs to mesh with ISO emergency or capacity market programs, and sort of make them more performance-based.

The third issue is default service pricing.

What's really happening in a lot of these states, is that the distribution utility is putting out to bid, in some fashion, default service, because a lot of customers haven't switched, particularly smaller customers.

There, there's a number of things state regulators can do to think about default service pricing in such a way that facilitates demand response. A lot of these issues were discussed in the New England demand response initiative process, and there's a whole set of recommendations for people who want to think through default service pricing and are struggling with this issue of, well, we did retail competition and not everybody would switch, but, low and behold, lots of the smaller customers haven't switched, so now what do we do?

MR. KATHAN: Thank you. Did you want to say something, Tom? Okay, with that, I will finish up on this panel and take what at this point will be a ten-minute break till 10:45. We'll start right at 10:45, so please, especially the panelists, make it back in time. Thank you.

(Recess.)

MR. KATHAN: All right, our first panelist will be Chris King from eMeter. The purpose of this panel is to focus on advanced metering and advanced metering infrastructure.

The EPAct of 2005 requests that we determine the saturation of advanced metering and communication systems. We've assembled this panel because we at FERC have little background on metering, and we're interested in understanding a little bit more about what are the key issues, what are the key developments in regards to advanced metering.

We've heard from many people that advanced metering is an enabling technology for demand response, and we'd like to learn a little bit more about it. So, Chris, why don't you get started?

(Slides.)

MR. KING: Thanks, Dave, thanks for having me, Commissioners. I'm going to start with a brief quote from one of my mentors, who said, "Tell me where you stand, and I'll tell you where you sit; tell me where you sit, and I'll tell you where you stand."

So, I want to be clear about where I'm coming from. I wear a lot of hats. One is at eMeter, which is a software company where I'm Chief Strategy Officer; another is as the Chair of the Demand Response Committee, a Silicon Valley leadership group which is a group of about 200 companies in Silicon Valley, started by David Packard, employing about 200,000 workers throughout the Valley, small and large companies.

Another hat I wear is as Co-Chair of the Demand

Response and Advanced Metering Coalition; another one is as Chair of the California Consumer Empowerment Alliance, which is important because we have been very active in the California proceedings.

And then just another one is as a Co-Chair of Open AMI, which is a standards organization in advanced metering.

So I'm going to answer these three questions in sequence. The first is the definition.

Advanced meters have been -- a lot of things have been called advanced meters, and there have been a lot of definitions out there. I would urge you to focus on a simple, functional definition, one that has been adopted in a few different places and seems to be a developing agreement around.

One of them is in the Energy Policy Act. It's the definition that's used for federal facilities. The Mid-Atlantic Distributed Resources Initiative, MADRI, California, and the Province of Ontario, Canada, have all adopted a definition that is essentially meters that record usage hourly and return it back to the utility at least daily, so that hourly/daily is the basic function.

In thinking about this, you might think of cell phones as an analogy. If you ask someone to define a cell phone today, you could have all kinds of definitions --

camera, Blackberry, e-mail -- but they all have a couple of common features -- they all have a keypad, they all have a microphone and a speaker and the ability to talk.

So that's the level, really, that regulators should be specifying functionality for advanced meters.

California got a little bit more specific, and I'll walk through their functionality briefly. California has taken a lot of heat for the energy crisis, which is well deserved, I should say.

(Laughter.)

MR. KING: But California has done a lot right. One of the things, just by way of example, is in the energy efficiency area. This is a long-term policy, and I think this is kind of an example that we need to keep in mind around what we're looking at here.

Over the last 30 years, starting in 1975, in California, the average consumption per person, per capita, was ten percent lower than the rest of the United States, so they started off a little bit better.

By 2005, that had dropped to over 40 percent less than the national average. If you look at the curves, California's average usage has stayed flat through that period, and the national usage has almost doubled, on average, so California has been extremely successful in that area.

Getting back to the advanced metering functions, there was a very extensive process going back to June of 2002, where California has adopted policies for demand response and advanced metering, and it was important because everyone participated -- the Energy Commission and various state agencies. Consumer groups were very active, all the utilities were active, industry was active.

There was no major group that was not represented there, and they came up with this hourly/daily definition that meters should support dynamic prices, customer access to data, support customer service by the utility, support other utility functions, and then, finally, interface with automated control.

Turning to the barriers, there are, in my mind, really two enormous barriers to doing this. We've known, as was mentioned earlier, that time-based rates have been a good thing for a hundred years.

The first barrier is this whole notion of the perfect being the enemy of the good. I'm going to tell you, you know, that one of the things that resulted in in our industry is, today, for example, utilities are going to install about 50,000 meters today, as we sit here.

Over 90 percent of those meters will do nothing more than provide monthly meter reads, even though there are all these other technologies that are out there. There's a search for the perfect solution. There are myths around, you know, do customers respond or not, do customers like time-based rates or not?

And there are answers to all of those, and, in fact, customers do like them, they do respond, and these programs do work, and there is no perfect solution.

So, moving forward with a good solution -- and I think, just to mention one utility, PG&E has really stuck themselves out there, saying, you know, we're going to do what Alison was saying we should do, and let's get the meters in. They've taken some heat because they have actually taken some initiative, and that would happen, no matter who it was and what they proposed, just because of the industry.

The second major barrier is the financial incentives that distribution utilities have. They don't have incentives to do this, to reduce demand, and we would suggest that a good solution there would be a rate-of-return type kicker. This was done with the energy efficiency programs.

Turning to specific recommendations for the FERC, I think the FERC could be helpful in adopting an advanced metering definition, one that would promote flexibility, because it's important that whatever technology is put out there, it's flexible to support additional options as they become available over time and are created in the market.

The second is just to continue to encourage ISOs to develop more demand response programs. Thank you.

MR. KATHAN: Thank you, Chris. Our next panelist is Sharon Allan from Elster Electricity. Sharon?

MS. ALLAN: I'd like to thank you for the opportunity to speak to you today. Sunday, I took the comments that have been filed from various regulators, utilities, and market participants, answering the question, what is the definition of an advanced meter?

The definitions submitted from these various ranges of participants in our market today, range from an electrical transducer that was a kilowatt hour device with a one-way communication board in it, to a high-function interval meter that did power quality monitoring, outage reporting, and there was even one that suggested there should be real-time to a meter, which could infer a broadband connection, since that utility has invested in broadband.

The definition in some instances has been influenced by the historical thinking of CNI. Historically, advanced meters, in the context of large commercial and industrial customers, is capable of measuring and recording interval data for both real and reactive energy.

This was out of a need to correlate time between

KVAR demand and KW demand. These solid-state meters have been shipping in the marketplace for over 20 years.

There are currently over 3100 utilities in the U.S. serving 136 million electric customers. From a metering perspective, 87 percent are residential; 12 percent are commercial; one percent industrial; and a very negligible amount of what we call interchange metering.

In 2005, of the estimated seven million new meters that shipped into the U.S., Elster estimates that less than three percent were interval meters and less than one percent were time-of-use meters.

Section 1252 of EPAct not only addresses the 13 percent CNI, but all the 87 percent residential, the time-based rate schedules that may be offered for time of use, critical peak pricing, and real-time pricing.

The Salt River Project is often cited in reference to their time-of-use program. Salt River Project today deploys time-of-use meters. They are now deploying time-of-use meters connected to a fixed network.

For residential real-time pricing, while there has been lots of talk about real-time pricing, very few residential real-time pricing. One of the residential real-time pricing that has been a pilot for the last two and a half years, is the Community Energy Cooperative by the Center for Neighborhood Technology, which has had a residential hourly real-time rate for the last two and a half years.

The Community Energy Cooperative utilized interval meters that were read monthly, and, a month later, the hour-by-hour data was given to consumers. Those consumers, during the period, would respond by manually changing their thermostats or controlling load themselves by knowing the prices.

Where confusion and uncertainty has muddied the waters for advanced metering, is in the area of this mass residential service. For the most part, these meters do not have clocks in them.

Time of use in interval meters that are used in the commercial and industrial sectors today in these demand response programs, have clocks in them.

What is the implication? You have to have a battery. Batteries are bad when we're looking at millions upon millions of residential customers where a utility would now have to maintain a change-out program and removing a battery.

So, innovators have come in, looking at how are ways that we can offer time-based pricing for this class of customer? And there's great confusion around terms of advanced meters, as inferred in the earlier session, where they were referred to as "crappy meters," a meter that last

50 years in the field, that runs seven days a week, 24 hours a day, that must accurately measure what consumers want and are billed.

An area, critical peak pricing, and time-of-use pricing, can be charged for customers, can be run three ways: You can implement time-of-use meters connected to a two-way network, whereby the time periods can be remotely changed.

You can install an interval meter, whereby those meters can be read, or you can put in a dumb kilowatt hour meter, whereby it bubbles to a concentrator that maintains time, that then goes back to a central station that cleans up the data, fills in any gaps, if they exist, and creates time-of-use or critical peak pricing.

The challenges I see for greater saturation of advanced metering, are threefold: First, if time-based usage is not in the meter, but now this notion of an advanced meter is a system, the retailers need to be given access to the AMI system, because it no longer is resident in the meter at the point of consumption.

If keeping time is not synchronized in the meter, but rather time-based usage is done somewhere else in the network, the utility requirements today that require display to the consumer, should be removed. This will add new innovations to take costs out of a meter.

If they are not being charged by what's being displayed on the meter, because the real charges occur somewhere in the network, it's incongruent with showing them a value on their meter today.

The last and most important challenge that I think we face, is, as we begin to look at how we do time-based pricing, metering is governing by ANSI standards today. ANSI standards say that a revenue quality time-based data must be certifiable.

ANSI C-12.13 and C-12.15, which codified electronic time of use, has been rolled into ANSI C-12.1. The Electricity Handbook, 10th Edition, Chapter 7, states "Accuracy must be reliable over a variety of environmental conditions and performance must be certified to an energy provider, consumer, and regulatory agency."

If AMR and AMI networks are now to perform the function of an advanced meter, that it is not being performed in the device, then it becomes an obligation to certify the entire network, so that consumers are accurately charged with the same certifiable quality that they get today in an electricity meter.

MR. KATHAN: Thank you, Sharon. Next is Doug Stinner from PPL Electric Utilities. The reason we wanted to have PPL here, was because they have had a rollout of an advanced metering structure system, and we wanted to hear some of their experiences with that.

MR. STINNER: Thank you, David. Good morning. Thank you for this opportunity to participate in this Technical Conference.

I'm going to try to keep my remarks brief, to allow time for questions.

First, I'd like to describe the metering system that we've installed at PPL Electric Utilities, and then explain our plans to further develop that system.

In 2002, we began implementation of an automated meter-reading system. It took three years to complete the implementation, and it involved the replacement or recalibration of over 1.3 million meters.

It involved the installation of communications systems in over 300 substations, and required modifications to the meter data system and billing systems. In total, the cost of this AMR system was about $160 million.

Operationally, the system processes data in the following way: The meter stores the data in registers. The communications servers at the substation, signal the meter and the meter sends data back to the server.

The data is then routed to the billing system and load research systems at the main office.

Communication is done via power line carrier technology for all of these meters, except for about 6,200 meters which use cellular communications. These are higher-voltage customers.

The benefits to PPL Electric Utilities and our customers, include the following: The elimination of our meter-reading workforce; customers no longer have meter-readers trouncing through their property to read the meter.

The system reduced the estimated meter reads. This resulted in fewer customer complaints and the need for fewer customer service positions.

The AMR system eliminated most special reads such as final bills and high-usage, and this resulted in fewer service positions.

With essentially an entire new meter system established, we needed fewer positions to maintain those meters.

One area where we've seen a great benefit, is improved outage restoration. We can query the meters via the power lines, to determine if a customer's power has been restored. This was beneficial in some of the storms that have come through our system.

Lastly, customer high-bill complaints can be more easily resolved by the customer service rep interrogating the meter data of that customer.

In 2004, PPL Electric Utilities filed a distribution rate case with the Pennsylvania Public Utility

Commission, requesting recovery for this investment. We're happy to say that in the final decision, the Commission allowed recovery of our AMR system.

That's the history of what we've accomplished to date with our AMR system. Now I'd like to describe our plans for further developing the system.

We will soon be completing a request for proposal to create a data repository, a meter data management system, a billing interface, and application software. This will provide:

First, the ability to offer new rate options to customers; second, the enhanced load scheduling, settlement, and reconciliation functions with PJM; third, enhanced analysis of the distribution system for planning purposes; and, last, the ability to identify theft of service.

These enhancements will change the system from an automated meter-reading system to an advanced metering system. In this process, Pennsylvania Electric Utilities has taken a phased approach in development of the system.

This accommodates evolving technologies; it accommodates evolving regulation; it accommodates needs of the retail and wholesale competitive markets; it avoids exposing ratepayers and shareholders to inappropriate risks, and, lastly, permits concepts to be tested prior to implementation. Thank you.

MR. KATHAN: Thank you, Doug. Our next panelist is Paul DeMartini from Southern California Edison. Paul?

MR. DeMARTINI: Thank you. Southern California Edison Company is pleased to have the opportunity to participate today. SCE is a national leader in demand response programs, with one of the largest portfolios of price-response and load-control programs in the country, with more than 1200 megawatts of peak demand response resources, including more than 300 megawatts alone from our air conditioning cycling program.

SEC also has one of the largest automated metering systems, now approaching 600,000 residential customers. This is a drive-by system, plus real-time interval meters on commercial and industrial customers with 200 KW or greater load.

Additionally, SCE has active technology trials of advanced metering systems involving narrow-band power line carrier and broadband over power line. On December 1, 2005, the California Public Utilities Commission approved our initial development of a next-generation advanced metering system for SCE's projected five million residential and small commercial customers.

If successful, SCE expects to have systemwide installation completed in 2013, at a projected potential cost of about a billion dollars.

We are actively engaged in internal business requirements development, as well as collaborating with technology vendors and industry research and standards organizations to create an effective business case for our customers and SCE.

To address the questions that were raised for the panel, SCE's definition of advanced metering: SCE believes that advanced metering and the related infrastructure, can and, in SCE's case, should do more than automate the meter-reading process and provide a means of interval load management and outage information.

Advanced meters and related two-way communication networks, can create the opportunity to develop smart connections with our customers, and automate aspects of our distribution grid operation to create an intelligent network.

The question about what metering infrastructure functions are needed to support further development, SCE's research suggests that the opportunity to leverage technology and program design to address customer education, notification, and retention, is an important consideration.

We have also found that automated demand response based on customer preferences, yields more demand response during an event than simply customer behavior alone. We have also identified that customer's specific addressability, that is, the ability to communicate directly to a specific set of customers, as opposed to a system broadcast, allows a variety of load control configurations for distribution grid management and/or load zones for locational marginal pricing.

The system must also allow flexibility for new rate options and demand response programs, that they may develop to support customer choice.

The challenges and barriers to greater saturation, we think, are threefold: The first is, you need to have a positive business case for both the customer and the utility.

Advanced metering programs need a case that combines operational benefits beyond meter-reading savings, plus demand response benefits. This is why, for SCE, for example, we are looking beyond AMR or sort of the basic AMI functionality that's been described for a system that can capture benefits from an intelligent grid perspective.

We're very sensitive to impacts on our customers' rates, and, therefore, an AMI business case should make sense internally and for our customers.

The second area has to do with technology life cycle versus the accounting life cycle. Many utilities, including us, are concerned about the potential that AMI technology will not last as long as its depreciation period.

What I mean by "last," is not the obsolescence, but rather the fact that it fails; it doesn't actually operate as long as it is expected to. AMI systems are currently thought to have about a 15-year lifespan.

Since the ANSI meters and communication networks will have to operate in very difficult environmental conditions over a long time, if the life of these systems falls short, this could result in significant cost impacts for our customers.

The third area has to do with serviceability, interoperability, and security. SCE believes that it's possible to balance the desire to adopt AMI technologies to support well-defined needs and requirements today, and allow for flexibility in tomorrow's uses in a secure system.

The main principles that we are addressing in our program are: Serviceability, interoperability, and security. Based on our current survey of AMI technology vendors, it appears that most products, AMI products, in the next year or two, will support these principles, which have also been identified by Gridwise Architecture Council, Intelligrid, and Open AMI.

We also believe that these more technical issues should be discussed at a national level, to avoid the potential for a highly fragmented market based on different regulatory requirements.

SCE has also been actively collaborating with several industry standards efforts, including, as mentioned before, AMI. Along with AMI, we are looking to also work with a new task force called Utility AMI, which will become the Utility Advisory Board to Open AMI.

This group will focus on these issues of serviceability, interoperability, and security requirements of advanced metering and demand response infrastructure, from a utility, energy services provider perspective. As such, we expect that this will become a valuable contribution to all the industry standards efforts, as well as that at Open AMI. Initial reaction from utilities has been supportive.

In summary, the challenges that need to be addressed for widespread deployment of advanced metering systems in the United States, are: SCE remains committed to working with the industry to develop solutions to these issues. We are also encouraged by the AMI technology vendor response to the need for product ability, versatility, and the ability to support significant improvements in electric system reliability, customer billing service options, and operational efficiencies.

It's important to recognize that each utility starts from a different set of operating characteristics, so, as has been said before, one business case does not fit all. At SCE, our goal is on getting it right for our customers, given our operational starting point.

For those that are interested in what we're doing, we have a website at www.sce.com/ami, where we post all of our information and updates on our program, including key workproducts, procurements, business cases, and filings. Thank you.

MR. KATHAN: Thank you, Paul. Our last panelist is Patti Harper -- and I'm going to really mess up your last name.

MS. SLABOSZEWICZ: Slaboszewicz.

MR. KATHAN: Thank you. I've asked Patti to talk about some work she did on surveying regulatory interest and response to advanced metering. Patti?

MS. SLABOSZEWICZ: Thank you, David, thank you very much for inviting me to participate today. David did ask me to do something a little bit different, rather than to focus on the definition of AMI, but to focus on the regulator view towards AMI and price response to demand response.

I'll start with some work I did in January of 2002 when I surveyed almost every state regulator in the U.S. It was in January of 2002, as I mentioned, which was shortly after the energy crisis that occurred in 2001, and I was a little surprised by the results.

I had thought that with the energy crisis, the regulators would be interested in time-based pricing for all customers. They would be interested in advanced metering that would support those prices, and found the exact opposite; that almost to a one, every regulator was interested in protecting the small customers.

They viewed the price volatility as being a temporary aberration in the wholesale market, that would hopefully go away when things settled down, and if utilities wanted to install AMI, that was fine, but they would pay for it out of their own savings. They weren't interested in having it in the rate base.

Then we move on to the Fall of 2004, where I was doing research for an AMR report that I wrote for UtiliPoint, and I found a totally different picture. By this time, the regulators had decided that rather than protect the customers, they needed to engage the customers to help reduce the price volatility, and that the only way to reduce price volatility was to reduce demand when the price went up, like with almost every product that we buy.

And, therefore, the regulators were interested in establishing long-term customer-friendly demand response programs. I think we can interpret that to mean they wanted these to be voluntary for customers to participate in.

They were interested in every form of dynamic pricing there was, whether it was critical peak rebate, critical peak pricing, hourly pricing, prices where the price would change four times, with four different price levels per day, but the prices didn't have to be contiguously offered, and the regulators were very interested in partnering with the utilities to install AMR.

Now, if we look at what happened after the Energy Policy Act passed in 2006, we're already seeing regulatory agencies starting to move. Ohio, I believe, is the first state to have opened up a proceeding to consider advanced metering in response to EPAct.

California, of course, had already been moving forward, and I think has tentatively decided that their ongoing proceedings will satisfy the requirements of EPAct.

Virginia has initiated a proceeding on net metering that might be possibly expanded to include AMI, and I noted that New York initiated a proceeding into the issues involved with deploying DPL, and perhaps that might be expanded to include advanced metering.

In 2004, we asked regulators what their attitude towards cost recovery for AMR was, and 35 percent reported that they would allow full recovery of prudent expenses; another 39 percent offered some recovery of prudent expenses, and only 17 percent said no.

Now, this may not be perfect, but it's a dramatic change from 2002, obviously.

As I mentioned, the commissions would support price-responsive demand response programs. Sixty-five percent would support conservation credits; 65 percent, time-of-use rates; and 70 percent, critical peak pricing.

So, I think the key point is that demand response needs to engage customers, and, in order to engage customers, we have to have products that are valuable to customers.

I'll refer to the story I told yesterday, which everyone liked, about my first cell phone, which I got in December of 1991. I remember it very well, because my son was in the hospital, and my brother gave me a phone like Carol has -- actually a little bit bigger than the one she had over there -- it was like a brick.

I really had no idea what to do with the cell phone. I signed up for a plan, out of loyalty to my brother, and I had to pay 25 cents per minute. There were no free anytime-minutes of any kind. None of my friends had cell phones. I didn't really know what to do with it.

Now, 15 years later, we have five cell phones in our family. We pay more for our cell phones than we do for our land lines. They're a key communication in our family. It's the only way I can get a hold of my kids at college. We call them at 3:00 a.m. in the morning and they're not in their dorm rooms. Cell phones are the only way.

(Laughter.)

MS. SLABOSZEWICZ: The key point is that it took time for customers to figure out what to do with cell phones, just like it will take customers time to figure out what to do with time-based pricing. I have no doubt that customers are smart enough to realize that -- maybe they don't understand what a kilowatt hour is, but they understand time and they understand money, and I think they can figure it out.

We need to give them tools, and we need to focus on tools that are valuable to customers, and for this, I really encourage that the discussion of price-responsive demand response, includes people representing the customers, because engineers will focus on what can be done, rather than what should be done, if we left them alone in the discussions.

So, we need to involve everybody. I think we can move forward. I don't think utilities will install crappy meters. I hate to disagree with Alison, but that's true.

I believe that anything a utility needs to install for AMI to support demand response, is very similar to what utilities would install to enable achieving operational efficiencies, and so I don't think we need anything particularly special for demand response, beyond what a utility should be installing to achieve their operational efficiencies. Thank you.

MR. KATHAN: Thank you, thank you to the whole panel. That was informative. We'll open it up to questions and answers, and Commissioner Brownell, do you have any questions?

COMMISSIONER BROWNELL: I do. Doug, you talked about the cost of the deployment of the meters, and then you alluded to savings because of quicker resolution of billing disputes, fewer service calls, more efficient collection of data.

But you didn't put a number to that. Is anybody tracking that number over time?

MR. STINNER: I would hope that's being tracked, but one thing to frame things up, when we presented the case to the commission for approval, the benefits to the system were offset by that cost, so the net impact to the customers, was very minimal in this AMR system.

COMMISSIONER BROWNELL: Okay, maybe you could get me whatever specifics you filed with the Pennsylvania Commission. What we often hear -- it's like talking about transmission, you know, we need $10 billion worth of transmission, but we don't talk about what that really means to the customer, which is also a minimal impact in many cases, of positive impact, so that would be helpful.

MR. STINNER: Sure.

COMMISSIONER BROWNELL: And the data that you collect, you can really kind of look at usage patterns, probably more efficiently, and is that available to competitive suppliers, or is that limited to access by PPL employees?

MR. STINNER: Well, in our current rules for competitive suppliers, only the high-voltage customers have hourly usage, that their competitive suppliers get. All other customers are based on load profiles.

But as we create this data repository and this meter data management system, that will allow us to have hourly data for all 1.3 million customers. So, moving forward to the competitive market, it could be certainly a value to them.

COMMISSIONER BROWNELL: So, it will be accessible to competitive providers?

MR. STINNER: Depending on if any rules change when we end our rate caps at the end of 2009. We're still under the restructuring.

I remember it well, but I also remember the battle over access to data of customers, which I think the courts overturned the Commission, and basically said, in restructuring -- they didn't put it this way, but I will -- when you wrote the check for stranded costs, the rules changed.

I'm hoping the Commission will look at that data access before the rate caps come off.

MR. KING: May I add something else? Doug didn't do the math, but it works out to $123 per meter.

One of the myths is that advanced metering is very expensive, but it's a little over $100 per meter. In their case and PG&E's case the business case is that the savings pay for the entire amount of that. In PG&E's case about 90 percent of it is the utility operating savings. The demand response savings cover that remaining ten percent, plus some.

COMMISSIONER BROWNELL: That's good information, because there is a misconception.

Paul, your 2013, it's a long time. Those meters better be pretty fancy. What do you anticipate you're your cost per meter to be?

MR. DE MARTINI: We expect right now what we're looking at is trying to improve on or equal the cost of sort of this average of around $125 to $150 installed per meter, which is kind of the current benchmark, as Chris has said, without getting into a specific price point that we're targeting.

But we're looking to be within that to be able to get this additional functionality. So 2013 to put it in context, we're looking at about a three and a half year deployment for the five million meters. We would start that at the end of 2009. So between now and then what we're looking to do is to revise our business case as well as work with the vendor community to develop that next generation meter.

COMMISSIONER BROWNELL: So you reviewed kind of all the options. And there was nothing off the shelf that satisfied your needs?

MR. DE MARTINI: No. And for a couple of reasons. One is that we'd already deployed automated metering in this drive-by system. The highest cost to the customers, which is in many cases -- in terms of the business case, is one of the biggest easy-hard dollar benefits you can quantify. We had already captured those benefits.

We also captured benefits in distribution automation. So our ability to respond to outages was already improved by some of the work we had done in terms of SCADA system deployment that we had done over the last ten years. We don't get quite the benefit others do there.

We also have a fairly large demand response program already. So we can't just get sort of the low-hanging fruit off of that. We have to think a little more creatively to sort of expand beyond that, sort of increase the pie, if you will in terms of how we get to additional demand response or price response.

We may be a bit unique, but what we're finding is that there are a set of utilities in the industry that have a similar situation. We need to push the envelope a little further to get to those benefits to make a positive case.

COMMISSIONER BROWNELL: You talked about the panel of utilities, probably a subset of EEI. Are there any customers, either wholesale or big retail providers, competitors on that panel? Or is it limited to utilities? Are there any public power people, co-ops?

MR. DE MARTINI: This group is actually being formed as we talk. This is being launched this week and it's open to any energy service providers and utilities. The idea is that those that are most directly working with the customer to understand what that need might be, as opposed to sort of the vendor community, which may be one step removed. There is an opportunity to sort of sharpen the focus around some of these issues from a technical standpoint and what some of the functional requirements may be, but primarily on the technical requirements.

COMMISSIONER BROWNELL: Thank you.

MR. KATHEN: One of the questions that was posed on the agenda -- and I'm not really sure I heard much on -- was the question of what are the infrastructure and/or functions that are required to support?

It's a broad question. But if there are different types of infrastructure requirements required for time-based rates versus for emergency and ancillary services I'd like to hear what is needed from the AMI system, or the meters themselves in order to support them. Is it in the current technology? Does it need a new technology, or does new functionality need to be added?

I'll throw it out to the panel.

MR. KING: David, I think the short answer is the current technology supports it.

In order to do a variety of time-based rates, anything from real-time pricing to time of use rates, you need to record data at some interval more often than once a month. The hourly base that these jurisdictions seem to be adopting will support all of those different rate options. Once you've got that data at that level you can consolidate it into different rate periods. This could change over the years as requirements change, and so on.

The other things that you need to support some of the other demand response programs, critical peak pricing, you need some sort of customer notification infrastructure that can be in various programs. It's done via communication to a smart thermostat. Paging signal; it can be done through an automated phone call. It could be done through some sort of mass media if you had wide-spread saturation. It doesn't go through the meter is kind of the bottom line there. You don't really need anything extra in the meter.

The other area is for control, some sort of automated control which always increases the amount of response you get from these programs and is popular with customers. That can use the same communication network. In fact, I think probably every advanced meter communication network supports load control as well, automated control. And again, the meter is usually not involved. And there's not really any reason to involve the meter. Those can also be separate communications systems and be cost effective as well.

Smart thermostat programs often use two-way paging in combination with advanced meters that use their own communication networks.

MR. DE MARTINI: One of the other things that I think -- building on what Chris said -- and maybe addressing part of the question that Commissioner Brownell asked -- is that we do see a difference in the scale of these systems. For the most part, most of the deployments to date -- with the exception of PPL, PECO and a very few others -- have been greater than a million meters.

With most of the smaller systems some of the scale issues in terms of the communication latency -- that is, the time it takes to send information back and forth -- haven't really been tested. As we looked at this, when we looked at a system the size of five million meters it became an issue of the geography.

So one of the things we're looking to address to do the things that Chris is talking about -- which we agree with -- is to be able to make sure that these systems can scale at the size that we're facing.

MS. ALLEN: When I look at what Ontario has laid out in their smart metering initiative they've put out what is believed to be the final step relative to metering. We talked in circles. As a community, you hear people describe AMR projects that they infer can be used for time based rates. AMR has traditionally been monthly reads. There is no clock. So we use examples and we make references that don't address the functionality.

I think Allison earlier had stated if we know what function we're trying to address then as a community we can offer various programs to do that.

In Toronto what the draft spec says is -- there's two camps. There's the camp that says that consumers need to have the ability in the future, if they want to integrate to their own meter and automate their house, or if energy service providers want to tap into that meter to offer service programs to the home, they have the ability to do that. It doesn't mean that you have to run a demand response program integrating directly to the meter. There are some examples where people have talked about the systems, giving access up in the head end. There is no one formula. And so it should not be proscriptive to dictate one way or the other.

In Toronto you can implement a one-way or a two-way system. You can implement time of use in the meter as long as you can remotely dynamically change the time-based pricing for consumers.

So a utility does not have to bill customers by collecting hourly by hourly intervals. Why is that? What is the importance of that? If you look at a million customers and you bring them back hourly by hourly data, while it can be used for load survey and many other very, very useful things, if you look at the payload you're looking at four million customers, about 12 gig, for one year. If you have to have spinning storage for three years, multiply that up. If you bring them back just to three tier time of use buckets for that same one million customers it's about 70 megabytes.

What utilities then have to decide is what am I trying to do in my project beyond time-based rate-making. They have to then equate the costs and the benefits of deploying whatever technology -- whether it's a meter with communications or a meter with a whole infrastructure -- versus the benefits. And the case is not based just upon demand response but across a myriad of utility applications that they are trying to integrate together.

MR. KING: David, I was remiss -- and I'm glad Doug talked about this. We always focus on the meters and the communications. The other piece that's critical to this is the data management software. That's critical for a couple of reasons. One is handling the data volumes that Sharon was talking about. Another is providing the ability to feed data to the utility systems. Another is to bring these different communication networks together that I was just talking about that might have different functions. Another one is to accommodate flexibility for the future. So if you have a flexible meta data management platform and new technologies come along, you can plug those in as well.

And then finally, from the customer perspective, putting on my SVLG hat for a moment, our customers are very eager to get access to this information. Many of them already have hourly meters as part of the California real-time metering for customers above 200 kW. But there's some frustration in accessing that data because it's through a somewhat cumbersome interface.

What we'd like to see -- we being SVLG -- is a standard interface -- and I believe the utilities agree with this as well -- where that data can be exchanged automatically and openly, provided there's appropriate security and authorization for using the data. But you could have an automated exchange so they can bring it in-house into their systems and therefore have their energy consultants get the data and help them manage their energy use.

MS. HARPER-SLABOSZEWICZ: I'd like to make one comment.

From the smaller customer point of view, I don't think the smaller customer is going to be satisfied with seeing a stream of hourly data. They need to have that data triggered to information. That's one of the things utilities are working very hard on is to figure out how to present that information to customers so they can actually use the information to manage their energy bill.

One of the things that's happened over just the past year is the move from just providing energy usage information on a dedicated device that is likely to get stuck under someone's sofa after their kids get hold of it to instead putting it where the customer used their data, talking about using instead of programmable communicating thermostats -- or sometimes abbreviated PCT -- so you'll send the signal to the customer programmable thermostat. And they need display information there, so when a customer goes to their thermostat they'll have the information where they need it.

That could be expanded to other areas rather than automatically control someone's washing machines and dryers, I'm a firm believer that we should not interfere with people's washing machines and dryers. But it would be reasonable to display what the current prices is there for them so they could decide whether they want to start a load of wash or start the dryer at that time.

This is not a case of what engineers can do versus what they should do. I don't want anyone turning off my dryer. But I would certainly appreciate the information at hand when I'm making a decision as to whether or not I would consume. It certainly wouldn't be appropriate to include this in every single appliance because not all appliances are that big of a load. The washing machine isn't actually that big of a load. But normally you go from the washing machine to the dryer, and the dryer is a bigger load.

I don't think it would be appropriate to put it on hair dryers and microwaves and toasters because they just don't stay on very long. We need to be reasonable about what we're doing. But we need to give real information to customers, not just streams of data. Most customers don't understand the concept of demand. They really don't even understand the concept of kilowatt hours.

MR. STINNER: A final comment:

When we talk about all this hourly data, if you put it in the context of demand response, by having all this data, even though it's a large volume for residential customers, we can go through that data and segment it so we know this class of customers used data this way; then target demand-side programs to the way the customers use the energy. From that we can see how much they may have reduced demand as they go on these programs. So it can be used to identify the best customers for programs, and then to calculate what their demand response has achieved as they go on those programs.

MR. DE MARTINI: David, to pick up on your question about requirements, there's two areas that we might suggest that folks ought to take a look at. One has to do with security.

As Sharon's describing, that is the nature of how these systems are designed, are evolving. It's no longer just at the meter. And so the security of these systems is going to be quite important in two ways: One is obviously protecting the customer's data and the usage. If we're collecting information at a very granular level, obviously there's a lot of intelligence you can derive from that in terms of what people are doing in and around their homes or in their businesses. So protecting that is quite important.

The second is, as we look at these systems to be interfacing with load control it seems to us that we need to be looking at how the application of the NERC cyber-security standards will apply to these systems, which really in the past hasn't really been applicable. Either the loads were below the NERC standards or the NERC standards have only just been -- in the last couple of years been evolving. So it's one of the areas we think is important to work with the industry, both the vendors and the utilities to better define that.

The other area we're focused on is this issue of serviceability. What I mean by that is really a couple of things. One is that the most important probably for this forum is that over time there's going to be creativity, innovation and different tariff options, different pricing schemes and so on. To the extent that those tariffs or pricing schemes are embedded in the system in some way, either by how you time bucket data or some way in communicating to the customer, or you do some processing of this information or intelligence out in the system as opposed to the back end, it's very important to be able to have the ability to remotely upgrade any sort of programming of software that's out there.

There's a lot of ways today that are available from a computing system standpoint where, for example, in large corporate networks it's very common today to have remote provisioning of software so that somebody doesn't actually come out to your desktop and change out the software; somebody does it from some other place and does it overnight or makes any upgrades, patches or bug fixes and the like. The same thing with these kind of systems is something we're looking at. As they get more sophisticated there will be an opportunity that we'll want to take advantage of that.

The other aspect obviously has to do with being able to manage very large complex networks and having the maintenance tools to be able to do that. Often that requires, again, this level of interface and what we see as two-way communication.

MR. KATHAN: Sharon.

MS. ALLEN: I know as FERC undertakes the responsibilities it has to measure the penetration, the first part of the survey I really believe that the only way that you can move forward is in the approach you're taking with a functional viewpoint because there is such diverse opinion and definition over what an advanced meter is. So the approach that you've taken on looking at are you doing three rate tiers or are you doing hourly will then have to be digested into how many different meters and systems that utilities are putting out there will be able to be utilized for time based rates.

There's evidence going on in the marketplace today that you can do residential without hourly. So while hourly is a good thing, it is not the only way. And as companies continue to innovate we see a merger of communication companies and metering companies. It's already happened in the market. And there probably will be further acquisitions that blend this together.

So as you're tasked with measuring it your only way, unless you come out with a definitive definition that is clear for all utilities to respond to, asking what's the penetration of an advanced meter, a distribution engineer is going to tell you that requires power quality monitoring. But for residential, if the focus is just on time-based then your response would be something different.

So structuring the questions that are what are the functional capabilities seems to be a much better approach and getting rid of the term 'advanced meter' because it's meaningless. There is not a unified meaning for it.

MR. KATHAN: I'd like to follow up. I'm a little confused still about something you said, Chris, and I think is implied in some of the answers I heard from Paul and Patti.

You're talking about the information back to the customer and you're talking about its being a separate system. What I think I'm hearing is possibly the technology will be implemented by 2013 in SCE or perhaps the information display Patti was referring to. Is that part of that AMI or is that still going to be a separate system? I have some confusion on that issue.

MS. HARPER-SLABOSZEWICZ: Can I answer that question, please?

The reason you may be confused is because different utilities will handle that differently. As Chris said, you can use the AMI network to talk to load control devices. Some utilities -- I believe SCE -- may be planning to use the AMI network to communicate to their customers. Other utilities may plan to use a separate network. Utilities will make that decision probably based upon what they already have deployed, what they want to accomplish with their demand response program, and you don't have to use the same network. You can use more than one; you might use three, you might use one. That's why there is no definitive answer to that question because you will see it implemented differently by different utilities.

MR. KATHAN: There's a whole group of them that are AMI?

MS. HARPER-SLABOSZEWICZ: That's where there's been some confusion in the market. AMI used to mean just the fixed network AMI system. When open AMI was formed they took a broader definition which included the fixed network AMI system. The meter data management system and I think the load control devices, they kind of had a bigger view of it. It created some confusion in the industry.

I still tend to think of AMI as just being the fixed network AMR system. Then you have the meter data management systems. You may have a separate network to communicate to the customers, which I maybe would call the R network, whatever you'd like to call it. There's also confusion on exactly what AMI encompasses.

MR. KATHAN: Anyone else?

MR. DE MARTINI: Just building on what Patti said -- and maybe this is something of what Chris was talking about -- you know, people trying to define this get onto the slippery slope between defining the overall objectives on the system versus getting into sort of the requirements of the system at a more technical or sort of system design basis.

Our view is it's more important to stay, from a policy standpoint, stay at the objective level and not sort of dive into the parameters because they will be one off. Each utility is going to have its own set of economics and these trade-offs that Patti was referring to in terms of looking at these three systems, I think it's recognized there are sort of three systems. The question is how to best integrate them from an economic standpoint, an engineering and economic standpoint.

In our case our outcome was that we are going down one track. That doesn't mean that that won't work for somebody else, a different solution.

MR. KATHAN: I'll open it up to any other questions from the staff.

MS. WHITE: I have one.

This morning one of the points that wasn't reached in the first presentation was the issue five that we needed to talk about was the lack of interval metering is a significant barrier to the deployment of price based demand response. I assume that's why Congress would ask us about both meters and demand response.

What I have been hearing mostly is that most of the programs are targeted first at commercial and industrial. So what are the barriers to wide scale deployment, or are utilities rolling it out to all of their customers?

MR. DE MARTINI: My remarks were largely based on the larger deployment out to the residential and small commercial because our larger customers, almost all of them over 200 kW or greater, have interval metering today. In fact, in California for the most part, at least for the investor-owned utilities, all have interval metering that are 200 kW or greater. Really the question in California, at least for the investor-owned utilities, is so what do we do in terms of making a business case for the residential and small commercial. My remarks were really focused on that. And the big difference between roughly 20,000 large CNI customers on interval metering and going to five million, it's a big scale difference.

MR. KING: I would answer that there are two barriers.

One is the business case Paul was talking about. What you find is that for most utilities it's marginal; if you don't include customer benefits and demand response benefits flow to customers. If the utility is looking at a big investment it's marginal payoff. It probably is cost effective, but it might not be. I'm taking some risk by making a big investment in a new area. Generally the decision is to back off and study it some more.

The business case becomes positive, largely so when you include demand response. What that requires, getting over the next barrier, which is the political barrier around demand response with small customers.

You mentioned the commercial customers. Utilities have forever done demand response with large customers partly because you get a lot more bang for your buck with those customers in large part because of the political realities and not wanting to rock the boat with all the residential and small commercial customers.

So I think one of the issues there is an attractive demand response program at the residential level. One is load control, which works fine and has been out there. On the pricing side, a price that is attractive. And we're talked about TOU forever. There have been studies forever. Critical peak pricing works really well. Getting large high levels of participation, marketing to customers and getting them to opt into the program is a challenge.

One thing that the City of Anaheim has actually done as a different approach where they're using the carrot, Alison's carrot to go to customers, leave them on their existing rate. And then when they call a critical peak they notify the customers. The customers get paid a rebate if they reduce their usage below their consumption for that day. So there's no penalty, no high price on that day. If they don't do anything they just pay their normal bill. If they actually provide some load reduction they get paid for it. In that sense it really works like the large customer programs. But because of the technology it's now available to small customers.

MS. HARPER-SLABOSZEWICZ: I'd like to add to that, if I could.

Part of it is kind of the chicken and the egg.

One of the reasons you didn't see a lot of customers switching to retail offerings in the various areas where that restructuring occurred was not only because customers just weren't engaged but maybe because the savings that were offered were not very great.

One of the reasons the savings offered were not very great was because the retail offerings really had to mirror the rates offered by the provider of last resort. Otherwise customers could not tell whether they would save money or not by going to their new rate.

One of the things that customers are is reasonably rational. If they can tell they're going to save money and they're going to save enough money, they will take action. But you have to make it clear that they're going to save money. How is a customer going to know that they're going to save money on a time based rate if they don't know when they use their energy. The utilities are faced with, well, if I'm going to install this am I going to get this into the rate base. I think there's a lot of work that could be done by a partnership between the regulators and the utilities. Once customers know their pattern of usage they will know whether they will benefit from having the time based rates, and I think you'll see some movement.

We programmed our programmable thermostat for the first time this year for our heater. We've had that programmable thermostat there for eight years. We never bothered before until this winter when we had two winters of increasing bills. It was finally high enough to get our attention.

And actually we did a pretty rigorous analysis of our energy use for gas this winter and we reduced our therm usage by sixty therms, accounting for different heating degree days per billing cycle. I actually calculated it per billing cycle, not just per month. I was pretty rigorous about it. I should have done it a long time ago. But actually I was trying to avoid a bill increase rather than get bill savings. Perhaps that was more motivating for me.

But you have to get it high enough to get the customer's attention and you have to give them information that they can use before they will become really engaged. So I think we have a chicken and egg thing here.

MS. ALLAN: I must not have answered this question eloquently enough when I was making my point.

The key point on the barrier for why we have not penetrated into residential -- and you see the programs in CNI -- is because the CNI had based infrastructure there. There are clocks in the meter. What utilities -- most of those meters provide pulse outputs such that the retailer or the consumer can hook up to their own meter, go into their train system or however they want to do to manage. So base infrastructure was there, called an interval meter, oftentimes with communications for time based rates to be applied to residential. There are not clocks in the meters today.

So there is this business case or this capital investment that has to be made called infrastructure for communications or meters that have clocks. This business case is now being framed in terms of terminology, AMR, AMI, the future nirvana meter of the future, the reality is you've got to be able to time to be able to bill someone.

MS. WHITE: Is somebody just going to have to tell them to do it?

MS. HARPER-SLABOSZEWICZ: If there's reasonable savings and customers know there are going to be reasonable savings they'll go for it.

MR. KING: I think you need to give the utilities a rate of return kicker, give them some financial advantage in doing this.

MR. KATHAN: What I've been hearing is, from everyone thus far, is basically that a uniform rollout is the way to do AMI. I just wanted to explore that a moment or two.

Is there an ability to do a targeted installation of AMI or advanced metering to get at certain customers or should it be done on a uniform basis across the whole service territory?

MR. KING: The economics don't work unless you do it in large scale. It affects both the costs and the benefits.

On the cost side it's much more expensive to install one by one and the communications tend to be much more expensive. In the California pricing pilot, which had meters scattered over the state, the price per meter was over $1000. And I told you earlier that in a large scale rollout it's closer to $100, a little over $100.

The other side is on the benefits. Again, as I mentioned earlier, you get operating benefits for the utility that covers almost all of the costs -- in some cases, all. If you do a scattered deployment you don't get those operating benefits either because you still have to send a meter reader out to walk the neighborhood. You don't have all the points to manage your outages and so on.

For both those reasons, to make the economics work you really need large scale.

MR. DE MARTINI: As Chris said, in the business case that we put together in response to the California Public Utilities Commission that we filed last March, 2005, we did look at a partial deployment scenario actually within that where there were several variations on that scenario. It was not positive. It was more negative then the full deployment case in our analysis.

To Chris's point, the back end systems costs, the network costs, by the time you had fewer customers to amortize over, you don't get all the labor savings benefits that you would normally accrue from not having the meter reading done. It becomes a bit tricky. We did look at it from a geography standpoint, looking at it from the price zones based on the statewide pricing pilot, trying to optimize around that. We looked at other aspects of geography where we could sort of cherry-pick the best places. But at the end of the day the numbers just didn't work.

MS. HARPER-SLABOSZEWICZ: If you turn it around from the customer point of view, as I said again, the customer has to do know when to use it to determine whether they would benefit from being on a time based rate.

If we're doing a voluntary program we're expecting the customer to either make the choice to move to the program or whether they should stay on the program, we have to give them the information. The only way to give them the information is, using Sharon's terminology, to have a clock somewhere in the metering at work to keep track of when they use energy. You have to install it for all customers to give all customers a chance to participate, and furthermore to give them the chance to decide whether they want to participate.

MR. GOLDENBERG: I just have a layman's question. But I was not clear on, for example, when I buy a computer one of the things that a lot of people say is you buy as much memory as you can possibly afford to buy because you're going to need it some time.

Is that really true for meters or, as Sharon said, you don't need to buy the most memory, the best meter, if you're going to roll it out. Or does the cost make it prohibitive to do it that way? And once you're going to roll out with the metered system you want to put as much into it as you can when you roll it out so that you can use it in the future.

MS. HARPER-SLABOSZEWICZ: If I could jump in again, I'll just say one more thing about this.

Utilities are not all the same. They have different risk preferences. You'll find some utilities are very focused on making sure they get an AMI system that works now, and they want it to be tried and true. And you'll have other utilities that are more concerned about it continuing to work into the future. You can see that in the California utilities. You have three entirely different responses to the same proceeding in California.

I think you'll expect to see that across the U.S. Utilities will have different risk preferences or different preferences for what they want. There's not really any one answer to that question.

MS. ALLAN: I'll go into your analogy on the pc. When you're going to Best Buy you don't say, 'I'd like to buy an advanced pc.' You say, 'I want one with a fast processor because I have an intensive application' or if you have teenagers that play the MMO, RPG games online you need intense graphics. There's different machines specialized for different things.

When you're looking at just time based, if that's all you were doing in a meter, the cost point would be different than if you have to meet being able to bi-directionally meter every resident because they may have their own windmills or renewables connected to their house. Once you start adding new functional requirements like voltage profiling, like renewables bi-directional metering, it's not just more memory and processing -- a bigger sized processor to handle the processing of that data. Now you're back-hauling more data back. If you go across the public network and you're using Verizon or Sprint, you're now paying for more data to move across the network. It's getting to a head end system that now you're storing more data so you need more disk space.

So it does make a difference. You can't just say, 'I want a meter that gives me time.' You have to say, I want a meter that performs what set of functions. And depending on the set of functions there is a different cost tag associated with that.

MR. GOLDENBERG: Suppose that I don't know what I'm going to do in the future. Do I put in a particular kind of meter today that will enable me to upgrade to do all those things that you were talking about? Or is that not -- Is that essentially cost-prohibitive and you have to put in what you want?

MS. ALLAN: It's cost-prohibitive today.

MR. DE MARTINI: Maybe I can add to clarify what you're asking.

I think the way that we look at it is you need to balance the needs of today in terms of making this all a business case based on what you can see in the next couple of years against making -- not foreclosing some opportunities, certain opportunities for the future. One in particular that I mentioned earlier when I talked about the serviceability is if, for example, you anticipate the potential -- you don't know exactly what the rate tariffs might be for price response, but you anticipate that you may want to explore some creative avenues down the road, the way that the system was designed is such that some of that rate information is embedded in the system.

You're going to want to make sure you have the ability to remotely upgrade or change that information in the system. So you may not know exactly what you're going to do but you can at least understand that you want to be able to do that and kind of define those sets of requirements, as Sharon said, so that you can accommodate that. So there are some things. But it is a balance. You're not going to be able to foretell everything that you'd ever want to do with these systems. But you certainly can leave yourself a few options, if you will, in a reasonable method that gets you -- that balances out the engineering economics.

COMMISSIONER BROWNELL: Can I ask a question, just pursuing this a little bit?

I understand ordering the Cadillac when you only need the Ford. I guess I shouldn't say that today.

(Laughter.)

COMMISSIONER BROWNELL: But I hear three entirely different systems in California. And 1000 years from now when this is all actually done am I going to find that by not defining some basic functionalities and basic data capabilities that I can't compare what's happening in different programs and in different parts of California? I mean I don't know if inter-operable is the right word. But am I going to end up, if I'm a State Commissioner, really not getting the kinds of information I need to get either to make appropriate rate design decisions or appropriate demand response programs because these guys -- these things operate entirely differently?

I'm concerned about this basic functionality. Does everything have a clock? Do they all have the basic same capabilities, whether you're going for the future or not, which I think is important?

I'm having a hard time getting comfortable with three completely different systems because I can see the nightmare that's going to happen.

MR. DE MARTINI: What I might point to is that the California Public Utilities Commission outlined six basic requirements for these systems. Each of us has -- Each of the three utilities has interpreted those requirements slightly differently in terms of the designs they're contemplating. But what I can say is from my understanding of what I am seeing in PG&E's testimony in terms of what they've proposed certainly, and what San Diego seems to be moving forward on, and from our own situation, we're going to meet those six requirements which satisfy the ability to support price responsive tariffs.

Now the difference comes in. Some of the added functionality in terms of how we need to make the business case work has been pointed out both from demand response, price response, as well as operational benefits. So in our case, for example, as I mentioned before, we don't get as many immediate benefits out of outage restoration from an AMR system. So one of the things we're looking at is trying to have the system be a little more sophisticated so we can get incremental benefits that we otherwise couldn't get.

We're also looking at things like incorporating an integrated service disconnect switch, so we might improve the benefits from not having to have people out there that do turn-on, turn-off for service, for customer service. That's not something every utility necessarily needs. We have a situation where roughly 30 percent of our customers, you know, basically move each year, and the turnover -- having that is something we think could be quite valuable. That's not the case for everybody.

So it's these other adders to try and make a positive business case that is sort of the distinction. The core systems in terms of the ability to deal with demand response, price-responsive tariffs I think are there. And then there's these trade-offs, as Patti said, in terms of whether you think the AMI system ought to be the communications system to interface with load control devices in and around the home. We think there's a benefit there. But others may think that the economics are better to have a separate system do that.

MR. KATHAN: This will be the last comment because we need to break for lunch.

MR. KING: It's important to think of this as an evolution. There's not one right system. And these systems are going to change over time. Right now California has probably over a dozen different metering systems jointly in operation. Even the utility electrical distribution systems are fundamentally different between Edison and PG&E. So it's that functional requirement, hourly, daily, ensures that you'll always have the flexibility to do whatever rate you can conceive of. And then the rest you can do at the head end of the system or add functions over time.

MR. KATHAN: Thank you. This has been a very enlightening panel. I just want to let you know that we have a very short, unfortunately, lunch period. We will try to get back here as close as possible to 12:45.

Just to let you know, down on the second floor there is a deli in the building. But there's also other options outside. The CNN building, which is over one or two buildings over, they have a deli. And there's Au Bon Pain on North Capitol.

(Whereupon, at 12:05 p.m., the conference was recessed, to reconvene at 12:45 p.m., this same day.)

AFTERNOON SESSION

(12:50 p.m.)

MR. KATHAN: I think we should get started. We still have three more panels to go. If we don't fall too far behind I think we'll get out of here at a reasonable time.

Our first panel this afternoon is taking a different perspective than the first panels. The first panel was looking at more of the higher level issues. We designed this panel to give more focus on what customers want, what are the various offerings that are being provided, and some of the options available.

Our first panelist is Peter Scarpelli from RETX. The reason I have Pete here is because he is involved -- his company is involved as being the operating agent for a task being operated by the International Energy Agency. The Commission has been in support of this project largely to learn and try to see if there's information that we can glean from activities happening in the rest of the world.

There are actually some neat projects, neat pilots that are happening in other countries. So I wanted to give a chance for Pete to kind of describe some of those and educate us on what we can learn from some of these other activities.

Pete.

MR. SCARPELLI: Thank you, David.

Good afternoon to all the members of the Panel and our FERC staff, and Commissioners, if they return.

I wanted to first mention that in the prepared comments that I have distributed we spent some time referring to the company, the background and the project background and stuff, so I won't waste time by referring to that here. But the project that we're working on with the International Energy Agency we refer to as Task 13, just the nomenclature, because it's the 13th project in the IEA DSM program.

In this project there are 12 international participants, and the United States is one of them. We would like to thank the U.S. Department of Energy, FERC, and the Demand Response Coordinating Committee for their participation in the project.

The project is designed to create tools and methodologies that will help facilitate demand response business case analysis. Some of these tools, as noted in my paper, include things such as a DR research library, a market potential calculator, evaluation methodology, a DR product data base -- and I highlight the word "product" -- and a DR technology data base, among other things. I'll offer just a few brief observations from this participation in this project.

First off, my personal observation is that I don't really think the United States is significantly different than the other participants in the project, meaning that most of these markets we all have different nuances on how the markets work and we all have different supply portfolios that demand response would integrate with. But that's true in the United States as well. If you do through the various regions there are different nuances. But I think fundamentally the same goal exists with all of our international participants. They all strive to include demand response into their markets primarily for the same reason I think the United States is. That is to create a demand spike balanced with supply side portfolio.

Some of -- Just to continue on this theme, there are a few common barriers that I've heard from our international colleagues that seem to be similar to what we face here in the United States. One that gets named a lot in our discussions is also the lack of interval meters and communication technologies. For example, one of the big challenges right now is that Sweden has recently declared the installation of new interval meters. Unfortunately, the declaration from the regulatory body did not necessarily say that they had to be communicated with on any regular basis. So while interval data might be collected, it might not actually be read more than a couple of times a year. That's because some areas are so remote.

Another challenge we continue to hear is also the tragedy of the commons. The benefits don't necessarily flow to one particular entity; they flow to many different entities. And trying to develop business cases for each entity is a little bit of a challenge.

Some of our participants were recently commenting that -- this might sound odd, but they're commenting that their markets are not peaky enough, meaning that they're getting a lot of flat curves, flat demand curves. If you don't get peaky enough there's really no need for an action. That's not necessarily a direct result of the market itself from a pricing perspective. Some have believed that there might have been some regulatory action to change the way the market operates and not giving a clear price signal.

The last thing I'll offer in the interest of time is one of the other issues that we hear from our friends is that there sometimes is a lack of price transparency, meaning that even though many of these countries utilize time of use rates on a regular basis they are still not necessarily able to transfer the real actual market price to the consumer.

In the interest of time, I have a whole bunch of examples, but I ran out of time. And I apologize.

MR. KATHAN: Thank you, Peter.

Our next panelist is Alan Wilcox from the Sacramento Municipal Utility District. We are interested in hearing from a public utility perspective. But my understanding is that you will be speaking to us about time based rates.

MR. WILCOX: Yes.

The Sacramento Municipal Utility District has over 580,000 residential and commercial customers within Sacramento County. We are an island within investor-owned utilities. Our customers benefit with rates that are 18 to 30 percent below the surrounding service area.

Since the early 1990s more than 25 percent of our retail revenues have come from time of use rates. Currently 100 percent of commercial customers -- in excess of 300 kW -- are on well-defined time of use rates that have prices approaching 20 cents per kilowatt hour in summer periods for up to 520 hours of the year. All residential and commercial customers have at least one time of use rate option, in some cases more than one. Enhanced pricing options include temperature-dependent pricing, residential thermal energy storage rates, and curtailment contracts.

SMUD has implemented a variety of demand response options that complement its rate design. We have air conditioning load management for residential customers. Customers receive a modest incentive to allow the District to cycle off their air conditioners during critical hours. Participation in this program exceeds 100,000 customers and can shed at the push of a button up to 156 megawatts of load.

We also have demand bid programs for industrial customers for bidding load shed during critical hours. This program is similar to critical peak pricing designs but is based on credits rather than higher pricing. It requires expensive interval metering, and consequently is limited to larger customers that have these hourly metering devices.

We also have voluntary load curtailment, which is something that's amazing. Our commercial customers actually will place up to 20 megawatts of load available in emergency conditions without any type of reimbursement.

And I mentioned previously the temperature dependent pricing which gives a very, very high penalty price signal for a limited number of customers on extremely hot days, giving us up to an additional 16 megawatts of curtailable load.

I wanted to extend into designing enhanced time of use rates without expensive metering devices. I wanted to share with you some of the concepts we have there.

In much the same way that deregulation was expected to be the silver bullet for curing all of the industry's growing issues, advanced metering technologies and critical peak pricing are now being touted as the cure-all. Before we take the plunge into raising rates to accommodate two-way communications for automatic response devices careful consideration of interim steps may prove more economical.

A typical TOU option with a four-month summer and six-hour peak for five days of the week will produce 520 hours of higher prices. If these hours are reduced to a two-month summer and a three-hour peak, the resulting 132 hours of higher prices would increase from 20 cents to as high as 35 to 40 cents per kilowatt hour. This strategy can be integrated nicely with customer education to avoid reduced thermostat settings for probably under $40 on thermostats during these critical hours. Combining this with an air conditioning load management device is likely to produce predictable load reduction at a much lower cost than is obtainable under a critical peak pricing strategy.

Combining these together gives us attainable product under existing technology without moving to advanced metering. However, as you well recognize, it does not provide that real time aspect that it may have.

The last item I wanted to discuss is pertaining to regulation in the context. The most important thing from our perspective is maintaining customer choice within our customer base. The thing that we would hope that you would adhere to is that from a regulatory perspective local control is the most significant issue, and that we should retain the customer option and the choice in their decisions on how to take power.

Thank you.

MR. KATHAN: Thank you, Alan.

The next two panelists, we're going to be hearing directly from the customer -- Thank you for that segue, Alan -- and hearing what are some of their issues and what they want and what are their challenges in providing demand response resources.

David Meade.

MR. MEADE: Thank you for this opportunity to share our perspectives on demand response.

Praxair is a member of ELCON, the Electricity Consumers Resource Council, a national association of industrial electricity users. Praxair itself is a large industrial gases producer. Our products are used to enhance efficiency, productivity, quality and environmental compliance in a wide variety of industries. To manufacture our products we process over a billion cubic feet of air per day. There's no charge for the air, but there are significant energy costs associated with the motors and compressors to handle this volume of air.

Our prime mover is electricity. We spend hundreds of millions of dollars on electricity each year. We're one of many ELCON members who, in aggregate, spend over ten billion dollars on electricity.

Now large industrial users often have some positive operating characteristics from a power perspective. Often they use large amounts of power in the first place. Demand is often in the many megawatts, if not the dozens or hundreds of megawatts. Industrial customers will often run at a high load factor, our constant usage profiles sometimes being 24/7 operations.

Industrial users oftentimes have a degree of flexibility. They can move in some cases production from more expensive times, powerwise, to less expensive times, such as nights and weekends. In some cases production can even be adjusted in real time.

Another level of flexibility which some industrials can bring is the ability to curtail their operations and their load, sometimes very quickly and on short notice. Given the operating flexibility that many industrials have, they lend themselves to being a productive demand response resource. And, further, the effective integration of this kind of demand response is instrumental to the reliable and economic operation of the power system.

Now speaking of the effective integration of demand response, we've had a diversity of experiences across the United States. And with that thought, there are three themes that I'd like to focus on. The first theme is that demand response should have all the opportunities of generation to provide energy capacity, and ancillary services. In some places we can provide one but not the other.

Demand response is an efficient accessible reliability and environmentally friendly resource. It should be encouraged, not discouraged or ignored. In some regulated jurisdictions utility suppliers decline to even consider demand response. In other areas demand response is hindered by the objections of generator interests who I believe wish to restrict competition and maximize their own revenues. And in other cases demand response can be compromised by the interests of marketers who wish to serve as intermediaries in facilitating demand response.

Four minutes already.

Theme number two.

(Laughter.)

MR. MEADE: Demand response ought to be encouraged and fairly compensated for the significant reliability and economic benefits which it brings. Economic encouragement can come in a variety of ways. Guaranteed minimum prices and event durations can be hoped for, particularly as these are constituted in certain demand and emergency programs. There should be no generation and transmission offset for demand response which is supplied at the energy markets. And further, demand response should be enabled to participate in energy markets where it does not yet have that capability.

It would be helpful, encouragement-wise, to establish permits to demand response opportunities by incorporating demand response provisions directly into the tariff provisions, along with generation. Meanwhile existing interruptible load should not be -- an interruptible contract should not be discontinued or sunsetted or compromised in those areas where utilities are not yet providing any kind of demand response opportunity at all and the customers have no other way of accessing that. Those utilities ought to be encouraged to provide that.

All the value that's generated by demand response, all the value that's generated by the load should go to the load without value being unduly hijacked by monopoly suppliers or intermediaries.

Theme number three is that all capable load should be eligible to participate. Barriers to entry should be eliminated. Last year certain customer interests had to fight to be able to bring their load into PJM demand response programs. They had to fight against utility claims that such participation was against state rules. This was ultimately resolved without a Commission order. But it would be useful to remove this kind of regulatory uncertainty moving forward and in all regions.

Another comment I would like to make is that just because a load is already interruptible under an existing contract or existing arrangements should not automatically disqualify that load from participating in other appropriate demand response venues.

Finally, I'd like to recognize, notwithstanding the challenges and opportunities, that there has been progress achieved with demand response. The inclusion and consideration of load -- especially in the RTOs and ISOs -- industrial customers appreciate that.

ISO New England and ERCOT were mentioned this morning, so I won't spend any more time on details with those.

And PJM has recently made some strides with their filing to further institutionalize demand response in their region. And they have a load to participate in synchronized reserves. Given the small positive steps we hope for continued and accelerated progress along the long road to incorporating demand response for the economic and reliability benefits to the power system, regardless of the state of restructuring in any given region.

MR. KATHAN: Thank you, David.

James, you're going to be talking on behalf of the Steel Manufacturers Association?

MR. BREW: Thanks, David.

SMA appreciates the chance to speak at this forum. I appreciate your efforts in organizing this panel and your stamina in sitting through all the panelists today.

The Steel Manufacturers Association represents the scrap-based electric arc furnace operators in North America. We operate about 130 facilities in 37 states. So it's not just a rust belt business.

They're dispersed throughout the United States. In fact, in your handout there's a map showing where many of them are. They're in Texas; they're in Florida; they're in New York; they're outside of Los Angeles. They account for over 50 percent of U.S. steel production last year, over 50 million tons of scrap recycled and recast into new steel products. They've developed highly efficient steel-making methodologies. They typically operate a batch process that runs around the clock, which is important for reasons I'll get to in a minute.

In my years in working with the steel-makers I have yet to come across the steel manager that didn't know exactly how many kilowatt hours it took to make a ton of steel. And the steel industry is all about tons produced, the volume out.

With that, it's interesting that the electric arc furnace operations have become the quintessential demand responsive load. We talked earlier in the day about New England and New York and the success of those programs. SMA's members provide over 3000 megawatts of curtailable load, which is more than the New England and New York programs combined. SMA members provide over 1200 megawatts of curtailable load on ten minutes' notice or less, which is more than New York's special case resources program combined. They are usually the largest electric load on a utility's system. They're almost certainly the largest curtailable load on the system. And they range in size from 50 to 150 megawatts of load.

Through the years steel-makers have evolved from a process from where curtailment was out of the question because it interfered with production to a state we have today where over half that curtailment can be cut off on ten minutes' notice or less. We've done that by evolving with utilities and developing tariffs and programs that will take advantage of that.

The reason is very straightforward: The batch process that we operate is an ideal resource for the utility because we can stop it and start it or hold off starting a new heat based on signals from the utility. That has made it an ideal resource. Many utilities have used it essentially as an operating reserve.

The problem is, of course, if you're being curtailed on a day ahead basis you can do some planning; if you're curtailed on ten minutes' notice you can't plan for it, which means you are encouraging production and productivity losses regardless. So to develop these programs it has always had to have been developed on the basis where it makes a business case for the steel-maker to do so.

That's really what I wanted to get back to here. The Commission has heard a lot of discussion today about time of day pricing, real-time pricing, and things that state regulators will eventually have to consider to develop.

One quick note there. Chuck Goldman talked this morning about a very successful RTP program in Georgia. I know of another southern utility that had a real-time pricing program that had no customers for years on the program. One finally signed up. It was a shredder that shredded cars for a steel-maker. They signed up for one year and got off it as quickly as they could. The reason was very straightforward: The tariff was designed in such a fashion that it contained base load responsibilities and ratchet features which made it uneconomical for the customer to do much of anything. And so the program simply had no subscribers.

Earlier today you were urged, I think by Allison and others for the Staff to take a closer look at some of the details. That's exactly what I'm suggesting. The Commission has direct responsibilities for implementation of demand response programs in the organized markets with the RTOs and the things like the PJM recent filing. You really do need to look at the details. It's not enough to say simply, yes, we're allowing load to participate if the rules effectively preclude it.

I couldn't urge you more strongly to take a close look at that because it does come down to program design. The customers will participate if you can find examples that work.

Just in closing, rather than point to the things that haven't worked, I would also urge you to look at the things that have. The emergency demand response programs in New England were subscribed very quickly. Those in New York have been very successful. They are customer-friendly programs that meet the customers' needs to make it worth their while to participate. They have worked. They have worked at retail as evidenced by our participation in countless programs, and the programs the Commission has approved have as well.

Thank you.

MR. KATHAN: Thank you, James.

The next two presenters will be coming from a different perspective, and part of the restructured markets and the way the ISOs have been formed in allowing additional participants bring in a new thinking on how to go after the customers.

Joe Franz will be talking from the competitive retailer perspective.

Joe.

MR. FRANZ: Thanks again for having us in to present.

Constellation New Energy is a competitive retail provider that provides customized energy solutions and comprehensive energy services to commercial and industrial customers. We're sort of an electric supplier to serve customers located within various service territories throughout the United States and Canada. Nationwide we serve about 15,000 megawatts of retail electric load. Customers include Boston University, Staples, Hyatt Hotels, Marriott, Georgia Pacific, as well as public entities such as school districts such as the Warwick, Rhode Island School District.

We are a subsidiary of Constellation Energy Group. Constellation Energy Group has three additional affiliates: Baltimore Gas & Electric, Constellation

Commodities Group, and Constellation Generation Group.

I'm here today on behalf of Constellation New Energy, which is the retail company.

Competitive retail markets like other regulated prices are tied to the market, creating the best opportunity for customers to engage in demand response. CNE is successfully implementing demand response in time-based rate products. Fully 60 percent of our customers are on some type of index product. It could be a real time price or a time based rate structure of some kind. This represents 9000 megawatts of load.

Constellation New Energy offers a number of different types of index product. The most common structure is what we call a block plus index structure, where the customer will buy a block of energy for portions of the load they do not feel they can take any risk on or have any load control. The rest they will let ride on an hourly index market. It could be a commodity price; it could be a commodity plus an hourly ancillary price.

In answer to the question of customers interested in participating, well, one other note on that. In addition to our own products we also promote ISO programs. We currently promote programs from New England, New York and Ercot markets as well as others.

It was interesting this morning, on the Georgia real time pricing, that they reached 80 percent market share. If you adjust our numbers by the portion of our customers that actually have interval meters and can participate in real time pricing programs, I think our market share would be very close to 80 percent as well.

I wanted to quickly talk about some of the challenges we're having in implementing programs. The first challenge, as I mentioned, is most of the customers on these products have interval meters. However, it's getting access to the data on those interval meters which is a real challenge.

Distribution companies own these meters. Distribution companies have put these meters in rate base. A lot of times these meters will have telemetry. We do receive in most cases the interval data from these meters. However the interval data comes to us 30 or 60 days after the customer uses it. Customers need to get access to these meters on a read-only basis so they can ping the meter whenever they need to, ping -- and if it's on an IP address, some way to determine what they're using at a point in time.

Customers need to be able to have that access. And to get that access they would need the distribution company to provide them with the password to that meter, a read-only password, and the phone number for that meter so they can access the data.

What CNE does with that data for our customers is we bring it into some information services. These information services let customers forecast their hourly usage, apply both distributions and retail products to it so they can see on an hourly basis what their consumption is going forward, let them do a scenario analysis around adjusting their load, if they adjust their schedule for tomorrow, how much money will they potentially save if they turn their generator on so they can do that cost-benefit analysis.

In addition, in some markets the uncertainty about the future market structures has stalled or delayed the implementation of demand programs and time-based rates. Utilities or ISOs are not permitted to offer programs or do not do so because cost recovery is uncertain. At the same time competitive suppliers such as Constellation New Energy will not offer these products if there's no real demand because customers stop rates and tariff do not reflect market prices.

Finally, for some of our customers that still do not have interval meters, that's the final barrier. If we can get more interval meters installed on additional customers they would be able to participate in real time pricing.

Thank you.

MR. KATHAN: Thank you, Joe.

The final panelist is Phil Giudice. And he is with EnerNoc. They are a demand response provider in a variety of the ISO markets.

Phil.

MR. GIUDICE: David, thank you for inviting us and giving me an opportunity to speak here.

We are a relatively new company. We've been really hard at our business model for the last couple of years. And at this time we have about 200 megawatts under management at about 500 client sites. Almost all of that is really focused around the capacity based type demand response programs.

We are active in New York, New England, PJM a little bit, and California. And what I take from the panelists before me and the panelists before me in yesterday's meeting over at the National Town Meeting is you have a very difficult job here to try and balance out all the advice and all the pushes and pulls of what different people think might be the ideal model here.

I don't sit here with an answer to what that ideal model is. I do know what's working for us and for our customers in those markets, and I can tell you a little bit about that.

We have really focused on kind of the highest priority societal need which we see, which is the lack of some capacity -- either generation capacity or transmission capacity -- in some of these markets, and then go into those markets either in existing programs or trying to work with utilities or others to establish contracts to go tap into the latent capability of commercial and industrial clients' ability to move load on command.

There's a lot of opportunity out there. There's a lot more opportunity than we thought there would be kind of getting into it. But one of the struggles is getting the market to sort of to open up enough for that. Customers want to participate. They particularly want to participate when they know that they're participating as kind of an avoidance of a peak need for the system, or last line of defense to keep the system on and reliable should the system be really constrained.

That's a great entry strategy. It's a lot better than building peaking capacity for that one percent of hours that account for about ten percent of the capacity needs across the country. We can very quickly go in, put our equipment in place, and aggregate that load so that the system operators then can get a very real time visibility as to how that load is actually performing when these events get called.

The amount of potential out there is pretty staggering. What we see in some of the program designs and some of the issues is sort of a veering from either one side of the spectrum or another side of the spectrum of trying to accommodate one user or another. One side of the spectrum is defined by the system operator's needs, which are very real needs for reliable, verifiable capacity when they call it and a willingness to pay for what it's worth in the context of their needs.

And on the other side of the spectrum is the end-user's needs, which is not about being in the energy markets -- not necessarily, nor not initially, at least. It's an economic decision: What's the payback; how much of a hassle is this going to be. The other need that they have is how stable is this kind of an opportunity as far as getting involved in this. Is it going to go away in a year or three months or something, or is it something that they're going to be able to count on on a kind of going forward basis.

Some programs will veer all the way over to the system operators and they'll want the demand response to be available for 12 hours and callable on any number of different triggers. That is understandable from a system operator, but it's not easy for demand response to participate. Other program designs veer toward the end user and say we're not going to have penalties, we're not going to require any technology; we're not going to -- you either participate or you don't whenever you feel like it. That's fine for end-users to get involved in it, but it doesn't really provide what that system operator really needs.

MR. GIUDICE: We've really called for a very thoughtful going through of what are the system operators needs, when does the peaking occur, what are the issues their trying to deal with. It gets back to Alison's comments earlier about being very clear about what goals are you trying to accomplish and then design the programs to actually fit that.

Metering is not particularly a problem. A lot of these clients already have the type of meters or were willing to put in metering equipment if the right economics are there. What we're really calling for is an open playing field and one of the things that might be something to consider is setting sort of a minimum standard of demand response -- a demand response portfolio standard that's set at something like 5 percent or so of peak load that has to be met with demand response. Or the utility or the RTO or ISO needs to explain why they can't do that or why it doesn't make sense to do that. That's not because 5 percent is any magic number. It's just enough in my mind to establish policies, procedures and practices to assure that demand response is getting looked at and get part of the opportunity here. Then it will achieve whatever economic value that makes sense in terms of the market.

This capacity-based demand response isn't the whole answer and it's really -- for many of our clients, it's only the beginning of sort of a way to get them involved in this. From this we do see them migrating in interest to get involved in more energy efficiency methods and also more price response and real-time pricing type opportunities. But certainly it's a nice to get them going on these kinds of activities.

Thank you for your attention.

MR. KATHAN: Thank you.

I'm going to start off on one question, which is actually geared toward you, Phil. You're very clear in saying that you're involved in the capacity markets. Is that the last thing you said? Because that's the customers first way to get to them or is this you're only going to be interested in participating in markets that have capacity? For example, the Midwest ISO was talking about doing an energy-only market. Is there any interest in participating in that type of market?

MR. GIUDICE: The details matter. Energy-only markets generically do not seem like they're going to be interesting. But the Midwest ISO also doesn't look to me like they need a lot of capacity, at least for a while, and so it doesn't surprise me that they're not really excited about the capacity issues that they're facing and so designing a market around energy only, conceptually, as an economist, I have a lot of appreciation for why energy-only markets really are an ideal way to go about this.

But the practical, and how it has actually rolled out, and what do you look at in places like New England, New York or PJM, it's not like energy-only markets seem to be signals to bring capacity on, not just demand response capacity, but generation capacity in an effective and efficient manner. So we definitely want to be and intend to be much more than capacity, especially our clients are asking us to get involved in energy information systems and get involved in upgrading capital spent on boilers, on HVAC controls, on lighting. It's a much bigger dream and vision that we have and our clients are asking us to get involve this than just capacity. Capacity just happens to be a really interesting way to get into the marketplace and it provides society a solution.

The New England ISO looked at last October and November that they were going to come up short, potentially, on natural gas to fire the natural gas generating fleet and said let's see if we can get some demand response up here real quick so that it could be available to us should we have to go onto to that instead of going to rolling blackouts, which is, of course, the other option they have. They put the program out. It got approved on November 30th. Something over 300 megawatts went into that program -- all new megawatts, all new clients. We were able to enable about a hundred megawatts of those folks over actually the first three weeks of the program. So a lot of latent capability there. A lot of interest there for those kinds of programs. It's a great entry strategy for us to be able to build into some of these others.

MR. MEADE: Could I comment on that, too, Dave? I'd just like to comment that even in energy-only markets, demand response can still potentially provide ancillary services, can still be a very important part of an emergency program and to the extent that demand response participates in energy markets. And, as I mentioned, it ought to have the corporate opportunities to do that. It would make their value even more so in an energy-only market. So it's still an important place for demand response and energy-only markets.

MR. KATHAN: I actually wanted to follow-up with Phil for a moment. That number of customers that signed up quickly for this winter what drove them to move so quickly? Is it the money?

MR. GIUDICE: Money was actually a stumbling block with many of those customers. They looked at it and said this isn't a good economic decision for us. Two things were important to getting them to sign up quickly. One, they read about the potential for blackouts. They saw it on the news. They saw Op-Eds. The ISO did a very effective job of getting the word out, spending time at the governors offices to let them know that this isn't just a "sky is falling" kind of situation. We really may have no options here, folks. We ought to get prepared for it. So a lot of customers really started looking at that and said, wow, we don't want to be standing on the sidelines here should the lights have to start going out to keep things going. That was one.

Second, there's a pretty strong sense by a lot of end users in New England that there's going to be some kind of capacity market that's going to come out in the not distant future. Maybe it won't be called LICAP. Maybe it will be something else. They know they want to be able to participate in that market in some manner. It's sort of like why get going on it now. But it was hard. Many of those internal processes for people to be able to do new things like this that had to get bubbled up through their inside counsel, outside counsel, CFO's offices. They sort of went around a lot of the normal decision-making processes to make that happen.

MR. KATHAN: Another question I have is a broader question to, I guess, Allen, Dave, Jay and Joe. I've heard a variety of different comments on what the customers want. I've heard some customers just want firm, unrisky offerings. Others want the flexibility and certainty.

Is it dependent upon the particular type of customer or industry? Is it dependent upon, as Joe was talking about, what's your default offer to determine what they're interested in? What do customers want in demand response?

MR. BREW: I'll take a quick stab at it first. It depends on the market you're in. For example, if you're taking a real-time pricing service from Georgia Power and you know it's a vertically-integrated utility with a lot of nuclear and coal capacity, you have a much better sense of the price risks associated with an RTP than you might have in other context.

Part of the reason, I think, the study that Chuck Goldman did on the real-time pricing experience and declining participation trends with the growing volatility in the spot wholesale markets. So, from a steel-makers perspective, many of whom have been on real-time pricing programs and were very comfortable with it for a long time because you understood the generation fleet and the risks that went with it. When those risks become harder to gauge and judge, the programs become much less attractive.

MR. FRANZ: For the markets we're doing business in, the majority of the customers are interested in time-based hourly products where they have that capability to fix portions of it with block plus index type purchases.

MR. KATHAN: Why is that? It is just that they've become comfortable with that?

MR. FRANZ: It seems to have been picking up over time. The markets initially opened and competition first started. A lot of customers were interested in a fixed price for all the kilowatt hours they consumed. As the markets evolved, they become more understanding watching how the real-time prices behave over time and they get more comfortable with participating with portions of their consumption that they feel they can control or take risks on, and then firming up prices for the production they do not want to take a risk on.

MR. KATHAN: Allen?

MR. WILCOX: Yes. If you back and track history a little bit -- if you look in the California markets just prior to deregulation, the industrial customers were clamoring for enhanced price signals, price risks. They were willing to take market risks, so we gave it to some of them. And, after we hit the problems that we did in deregulation, they were begging to get back on hedge positions, more solid rates.

The one thing from demand response that I would like to suggest it moves along the avenue that James was talking about. We can't establish a one size fits all concept. It's important that, as a utility, we understand those individual customers, their individual risk propensities, what they're willing to go through. Inherently, it means, as a utility, we should be interested in how they operate, where they can put offerings on the table and understanding how that may benefit, not only our electric side on the power supply, but including distribution benefits as well as transmission benefits. I think it takes a very customer-specific response, not just to one size that you're going to apply to everybody, enforcing it onto the industry as a whole.

MR. FRANZ: I would second that. We found that we necessarily have to sell literally hundreds of flavors of real-time pricing and demand response types of products in order to meet the customers needs.

MR. MEADE: I would agree. In aggregate, customers want flexibility from their suppliers. They want to have their specific meeds met and they want options and a truly competitive market will bring these desired options to customers.

MR. SCARPELLI: I just offer one other data point. I don't mean to beat the horse on this, but my friends in Denmark have reported that they started real-time pricing in the early '90s. They also happen to have a fully deregulated marketplace with multiple suppliers. What they found in recent years is that the demand curve actually remained flat. Essentially, what they've seen happen is, even though the market went to a real-time pricing structure, most consumers did migrate toward some sort of supplier to essentially fix the price. That's just one other data point to consider.

MR. KATHAN: I guess that goes to a question I would ask to Joe and anyone else can pipe in.

Is your data points mostly customers who are on a default real-time price or a market-based default? Are there customers that you have gained who are on more of a firm or a fixed standard offer?

MR. FRANZ: I would say all cases. Some cases where they've got a market-based default offer, maybe that adjusts periodically -- every three months or every six months or something like that. Other cases where they're on an index that might vary with time of use -- I'm sorry, vary in hourly index. In other cases we're competing directly against customers coming from other suppliers as well as we're renewing a lot of our customers. We've had them long enough that we've renewed their contracts a number of times and each time we represent them the full range of options from fixed price to complete index options and discuss what's the best fit for them. They have definitely migrated to this more real-time pricing structure.

MR. GOLDENBERG: I'd like to ask Mr. Meade what he meant when he said all the value should go to the load and how he would define value in that context.

MR. MEADE: The demand response participation generates value either through capacity credits or energy credits of some kind, and we've seen, in some cases, where if an intermediary were required to providing a demand response resource, that being in a monopoly position and being able -- it's all way or no way and we'll give you a 50/50 split. And, you know, we would find that to be a disproportionate taking of our demand response value just because they basically have to be in the middle of the transaction. Not that they might not be entitled to some compensation for their role, but that's just an example of too much value being taken. The customers basically sit behind the eight ball.

MR. GOLDENBERG: How do you stand on the issue that was discussed in the first panel with respect to subsidies and whether or not you should have your retail price subtracted out as part of your demand response payment?

MR. MEADE: Just to reiterate, there should be no generation and transmission offset to demand and response sales and the energy markets I don't consider that to be a subsidy in the scheme of things.

MR. BREW: Michael, if I could add on that.

From, I think, a systems operator's perspective, if you add a hundred megawatts of supply or you reduce a hundred megawatts of load, you've got the input to the system in terms of keeping the system balance.

A lot of the discussion on subsidy get related to what's the cost or often ignores the cost of value to the load. Sometime ago I think the FERC staff, in one of their reports, had an estimated supply curve when prices are going vertical and the benefits to the system of cutting that 100 megawatts of load. Part of the answer, at least from our perspective, is that if you're providing that value why shouldn't you be compensated the same way as supply, however you want to define that?

If the next bid into the system operator is to reduce the 100 megawatt as oppose to adding 100 megawatts and it's clearing at 80 bucks, why shouldn't you be paid its value?

MR. MEADE: It's reducing the LLPs over an entire region. There's benefits being realized over an entire region that likely far exceed the amount being paid for that demand response itself.

MR. GOLDENBERG: If I understand it, then you're not arguing that you are reselling the power. That, for example, you would have purchased at a fixed retail rate into the wholesale market, which is my understanding of what the subtraction is all about.

MR. MEADE: I wouldn't characterize it as reselling energy.

MR. WILCOX: It's an interesting concept. From my perspective, they're welcomed to sell it back at the prevailing market price if they have a take or pay contract. If they have like a two part rate with a base line, then they're more than welcome to take that product, sell it back to the utility. It's very unusual, if we're mixing price incentives with demand response incentives, they have to be dovetailed together. They can't be balanced up in such a way that we provide a double credit for the same energy supply.

MR. GIUDICE: That's my perspective as well. From an energy standpoint, you have to look at the price response type programs and where the benefits are being generated and how they're being shared. The capacity programs are really quite different. There isn't an equivalent. The commercial customer that reduces their load on call for the two hours, as the insurance policy to keep the grid on, they're actually making choices, doing things different in their business so they can make that capacity available to the grid, which is just a generating station needing to do things to make that available. That's sort of going beyond whatever is in their normal course of business to do something that benefits society and then letting them get compensated equivalent to whatever capacity prices are trading at in that market or under whatever contracts. It eliminates the issue of any subsidies or anything else.

The initial program with ISO New England for Southwest Connecticut was open to generators. It was open to new generation, expansion of existing stations, demand response conservation and whatever cleared the market -- whatever was the best economic answer got contracts to go forward and deliver those megawatts.

MS. McOMBER: I had a comment from Alcoa. I'd like to hear if anybody had a comment about regarding the legal restrictions that prevent the resale of government subsidized power by retail customers. Did anybody have a little bit more information on that for me from this panel?

MR. BREW: I don't. No.

MS. McOMBER: Thanks.

MR. KATHAN: David, I just want to follow-up. You were saying you don't want any middle man when you're selling your demand response. Is that different whether you're in a restructured market, whether you're served by an vertically-integrated utility, whether you're an ISO or not? Where is your major issue or is it just across the board?

MR. MEADE: We don't want middle men or intermediaries where they don't make sense or don't add value. If we are able to take care of our own business through direct registration with the RTOs, then we want to do it that way. We don't necessarily want to have utilities or marketers having to do what we can do ourselves for us.

Now if there is value to be brought by an intermediary, such as metering telecommunications, it's like -- you know, then by all means. We shouldn't hesitate to use that and negotiate an appropriate compensation for that, which may have nothing to do with the demand response value actually getting created. Basically, we want to be able to do it ourselves if we can, and if we need to involve other parties, then that would be our negotiated agreement with them at a fair price and not with us being held hostage.

MR. KATHAN: Let me just follow-up. Would one way of doing it yourself be to be fully into an RTP type of a contract where you could then make decisions and you are in a sense -- you know, there's no middle man if what you're getting is a pass through of the wholesale price. You're making the decisions. You're getting the value from the reductions.

MR. MEADE: You're talking about a pure energy market type participating.

MR. KATHAN: Right.

(Pause.)

MR. MEADE: I see what you're saying, Dave. We'd like to fix prices too sometimes or we'd like to -- like I said, we'd like to have options. We might have a whole portfolio of different products that we're using across the system. But, even if we were to have a fixed price by some means, we would still want the ability to participate in energy demand response. Basically, drop load, provide an alterative to generation to the clearing and to be compensated accordingly.

MR. KATHAN: James, you wanted to say something?

MR. BREW: A quick note. Firstly, it was clearly simpler in a vertically-integrated instance where the utility owned the generation and they were looking at their demand response load basically for capacity because the energy really rolled into a weighted average fuel cost. So the energy issue really wasn't a driving factor in the legacy-type of interruptible service arrangements. The second is -- and this gets to the whole range of options. If you're simply going to do RTP and you're suddenly telling the customer figure out what your price point is for sell curtailing, you'll do that but that price point, for a lot of businesses, is going to be very high.

If you're going to be saying at what point would I participate in the market and give it up, that's curtailed. That's less than that. I've got to cover my costs. That gets into what level of payment form the system makes it worthwhile to do so. You can walk along your price curve looking at the system benefits you're providing and deciding where you'd like to come out. And that's, I think, part of the whole development of the energy markets in PJM and New York is to try to encourage those loads that can be flexible, since you don't have the meters in all the homes, to get some actual price response on the energy side. Otherwise, you'll see participation levels. Even in the energy markets now in New York, you've got what? Several hundred people subscribe to the capacity programs and 18 are participating in the energy market. So, if you're trying to energize that market, you can't simply say just put them on ITP.

MS. WHITE: I guess I'm still trying to understand something. I wish I had your comments in front of me. I really enjoyed reading them. But you said something about you can't do it on 10-minutes notice. Are you saying that there are 10-minute ahead notices that you think it's deliberate?

MR. BREW: No. What I was saying there was that SMA's members have collectively, from our survey, about 1200 megawatts of load that's curtailable on 10 minutes notice or less. We've worked that out through utilities over time. The point I was making earlier was, when you're scheduling production, an event that will lead to a 10-spend event when you're called is something you can't plan for. It's just going to happen. You're going to lose the productivity from what you were doing at the time. You're going to have down time. There are a lot of efficiency losses. Even if you try to make up the production later, you've lost time. There are costs involved, whereas, if you're working off a Day Ahead or something, you can schedule maintenance. If you're just cut off in the middle of the day, you can't do that.

For those steel makers that have agreed to 10-minute type of notice, the compensation for doing that has valued that in.

MR. KATHAN: Allen, I wanted to ask more questions about a statement. I think you were saying that you've been able to, with a combination of the air conditioner cycling program -- maybe I'm not quite clear on this. You're not needing to fully go to detailed metering? Perhaps you can talk a little more about that point you were making.

MR. WILCOX: What we're looking at, SMUD, is piloting. I know that was a nasty word in one of the earlier sessions, but setting up products rate designs so that integrate direct load control potentially with time of use options with very narrow peaks, we're looking at that as an alternative to going all the way up to expensive two-way communication. We're just now in the early design stages of this. Over the last several years, we've done real-time pricing products, monthly indexing and we even did a residential critical peak pricing product. What we learned out of that one was that -- I was very surprised this morning to see that the metering cost had gone down to 125 to 150 per data meter point on the critical peak pricing type meters. We were used to more around the 4 to $600 range. In addition, up to a thousand dollars for automatic response devices in our pilot. So it was something where we were looking for another strategy that would get us to an improved price signal to those residential customers without escalating their fixed costs significantly. That's something we're looking into exploring at this time. We think there's still a lot on the table with enhanced time-of-use rate designs. By looking at narrower summer periods -- three seasons -- and there's relatively inexpensive meters on the market today that produce up to 12 seasons per year with three periods per season, so there's a lot of room in there to move without jumping all the way to the two-way communication.

MR. KATHAN: Thank you.

Pete, I actually wanted to ask you about looking at your notes and about Norway. Norway, I believe, the Staatnet is pretty much an energy-only type of market. They've been moving to incorporating options.

Could you speak on that a bit?

MR. SCARPELLI: I'll speak as much as I can. The Norway market does work on an energy basis, as you indicated. However, the TSO is named Staatnet, similarly to an ISO here. They have a responsibility for maintaining the operating reserves. Since they have that responsibility, what they've done was to create something they call a reserve option market to get to the 2000 megawatts that they need for their operating reserves. From a system of 2300 a total megawatt system in their reserve option market they allow both load and generation to bid on an equal footing and they've established rules for allowing that. They've been doing this for a couple of years now and it's been very successful from their perspective.

They've received a high volume of load. I don't have the exact number, but a high volume of load participation in that 2000 megawatts. It's gone so well from their perspective that they are currently expanding their options down to smaller consumers, so they're currently designing pilot projects. Again, a nasty word, but they're currently designing projects to integrate smaller consumers into the reserve option market.

From their perspective, they're driving towards making sure that any demand response is an actual function, a direct function of market structures. This is one way they thought that they achieved that.

MR. KATHAN: But it's providing operating reserves.

MR. SCARPELLI: That's the key. It's operating reserves and it's a call option, essentially, formed from the TSO.

MR. KATHAN: That's it for me as far as the number of questions I have.

Actually, we do have a few moments of our time left on this panel. If there's anybody who wants to make any additional comments.

MR. BREW: I'll take a shot at it. One thing that came up earlier that I wanted to emphasize that I think is very important for the Commission that's establishing consistency with the state commissions on their policies. New York is a superb example of where the New York PSC told it's utilities to convert its legacy interruptible service programs to conform to the New York ISO programs. So, across the state -- whichever zone I'm in, there's a consistent program where there's capacity or energy in contrast to what you experienced recently with PJM trying to figure out what you can do in various states with the PJM program.

Certainly, a key role for the Commission is establishing that sort of consistency and support of approaches. There's no easier way to undermine programs at either the state or federal level than if you're telling the consumer different things.

And a follow-up to that is I talked a couple of times about the 10-minute curtailment that our members often provide to different utilities and different places on a retail basis. If you contrast that to basically the fact that load really isn't participating in the operating reserve markets -- in the organized markets, there's a big disconnect between what historically has been accomplished using those loads for reliability operating reserve purposes and what you're seeing in the organized markets there as they exist now.

That's another thing where I think, in terms of looking at the practice rather than the policy, what are you actually getting in terms of results.

MR. KATHAN: Pete?

MR. SCARPELLI: My final thought is relatively small in its use, frankly. But, whenever I meet with our international colleagues, they constantly have beat in my head that I'm not suppose to call demand response programs "programs." They regularly -- all the time -- tell me that from their perspective they should be considered as demand response products.

Now, particularly the northern Europeans are very market-based focused. So, from their perspective, demand response is a product that participates in the market, not a program designed from a regulatory perspective. It's just a small thought.

MR. KATHAN: What does that imply then? How do you then offer them?

MR. SCARPELLI: It implies to me we have to go back to the reserve option market again from their perspective. That is a tool that operates in the market. I would offer similar thoughts to the New England efforts and the New York efforts, specifically. It doesn't matter what you think about ICAP. It is part of the market structure and the way that demand response participates, and it is actually participating in the market, per say. So calling it a program may not be an appropriate thing. It's actually a product that works in the market. Again, it's a relatively small thing, but if we start to talk about things in terms of -- in these sort of terms, we might start to get to a place where it actually works in conjunction with the market as opposed to outside the market that we heard this morning.

MS. WHITE: I think one of the things somebody said yesterday is calling it a program makes it sounds like a temporary thing that's going to go away, and what you're trying to establish is long-term certainty for customers.

MR. KATHAN: Okay. If there's nothing else, why don't we say thank you to this panel and we'll move on to the next panel.

While they're getting up and the next panel is sitting down, I just want to say just a few words. The next two panels are going to have more of a focus on the regional focus. We're going to look at each of the various regions throughout the country.

Thank you.

(Pause.)

MR. KATHAN: In the interest of time, will people please sit down or take the conversations outside so we can move on to our next panel.

The next two panels, as I mentioned right after the last panel, are focused on regional perspectives. Part of what Congress has asked us to do is look at demand response and advanced metering on a regional basis. So we're interested in receiving information from how demand response has been working. What are the challenges? What are the barriers for each of the particular markets.

The first panel will focus on a number of different regions and we have representatives from the Midwest, from Texas, California and the Pacific Northwest. We'd like to hear what's been happening primarily and I'd like to have some discussion, after everybody goes through, focused on each of the regions.

Why don't we start with the Midwest? And, Ron, why don't you start off with the MISO perspective.

MR. McNAMARA: Thank you. It's a pleasure to be here. Thanks for extending the invitation to the MISO. What I'd like to do is provide a brief summary of the prepared comments that I provided to you. I look forward to the discussion that follows this.

As everybody will be aware, the MISO is a relatively new market. We started on April 1st with the centralized dispatch across all or parts of 15 states. We've been termed an "energy-only" market for more reasons than one. Primarily, because we have multiple control areas and those multiple control areas are responsible for most, if not all, the ancillary services. So what we actually centrally dispatch is the "energy component" of that.

That being said, demand response is of particular interest to the Midwest ISO. That is because we are looking right now actively, in conjunction with our stakeholders, at the issue of capacity mechanisms or capacity markets. You can't talk about, in our opinion, the notion of capacity without talking about the effectiveness of demand response because demand response effectively competes with peaking generation or peaking units to make load and generation balance. So it is a critical element of our market design that we're looking at and we're under orders from FERC to actually respond to the question of capacity in our footprint very shortly.

Let me review briefly. Like all our TOs, the MISO is required to perform regional transmission planning. We have to meet that requirement in 2003 and 2005. We have produced a transmission expansion plan. The planning process itself is an open process. It looks at both local issues as well as kind of regional and RTO-level issues, so it's kind of a bottom up and top down approach. It's focused primarily on reliability and not economics. It involves, certainly, as I said, it's an open process involving both stakeholders, including state regulators.

The one thing I'd like to now go on to is the fact that when you've established a market, things change. Markets inherently change the planning process in many ways. The planning process is a substitute for the market, not to say that markets don't use planning processes, but there's a certain amount of substitutability there, in particular, prices matter. There have been quotes made that we will run out of generation or the surplus in generation will run out in the next four to eight years across the United States.

To that I respond, and we respond, at what price? Does that assume the prices will stay the same or are prices going to change? I would like to distinguish very carefully between what we call "price response and demand," which is the development of a true demand curve, a demand curve that responds to price where quantity responds to price, including quantity in real time or as close to real time as you can possibly get it as compared to what is more commonly used in the industry -- the interruptible tariffs or the interruptible contracts, which are there really for reliability purposes and are not there to really base economic decisions on.

When we talk about price responsive demand, we're talking about how do we encourage and facilitate achieving a slope to the demand curve such that as price changes so to does the quantity demanded. Underpinning the planning process, as we know it today, is an idea or a paradigm in which really load is the same thing as demand. We take load as a given and then plan the cheapest way to meet that load. Once you open the planning process up to the fact that, if prices change, demand may change as well. You need to incorporate that into the planning process and things become a little bit different.

We are investigating ways internally and externally with our stakeholders about how we can better plan -- in the existence of a market, how can we use the information coming out from locational marginal prices to actually get a better plan for the future needs of the footprint. Once you open up a market, I think you also have to revisit how you actually define the concept of reliability. If, at certain prices, people will respond and demand less of the good, I think that has flow-on effect in terms of how you measure reliability and how you actually achieve a reliable system. That is something we're going to have to look at within the MISO footprint.

In closing, let me leave that the goal of the market ultimately -- and also I would include in that the planning process - is what we need to be able to do is to price reliability. In any market, you don't have a market until it's both supply and demand operating as a scissor that you effectively get a real price. So what we need to do with the market is, to the greatest extent possible, be able to price reliability. That's not the goal in and of itself. The goal, ultimately for society -- the objective should be that that price signal then flows on and leads to the appropriate investment and we get the reliable system that we're willing to pay for and we understand what the consequences of our action in demand are. We want to be able to price reliability with the goal of being able to send the appropriate price signals so you get investment. Underpinning all of this will obviously need to be long-term contracts that reflect the value of electricity.

MR. KATHAN: Thank you, Ron.

Our next panelist is Chairman Jeff Davis of the Missouri PSC.

MR. DAVIS: Thank you, Your Honor.

I'm proud to be here representing the great state of Missouri. We have a very diverse electricity landscape. We have four investor-owned utilities. We have approximately 50 rural electric cooperatives with an extensive transmission and generation network. We have an even greater number of small municipal utilities that own some generation and very little, if any, transmission in pockets all over our state.

Missouri has not restructured and there's no movement to do so. We have some the cheapest residential and commercial electric rates in the nation. Our people enjoy those rates and experience shows us at the Commission that it can be very difficult to change their consumption patterns. The four investor-owned utilities that we regulate offer a wide variety of demand response and time-based rates. All four of our investor-owned utilities have seasonal rates that are higher in the peak summer months. We recently improved an inverted block rate design for Empire District Electric in their last rate case. I believe we actually have some declining block rate designs that are actually still on the books.

All four of our industrial-owned utilities offer optional time-of-day rates. Most customers are interested in these programs because we have low rates and there's not that much of a price difference. Aquilla does have a mandatory program for part of their territory and Ameren has had a pilot project each of the last two summers to combine time-of-day rates with critical peak pricing.

Kansas City Power and Light and Aquilla offer real time pricing options for some of their customers. These programs were initially popular, but now they have relatively few participants because of the cost concerns. More importantly, based on what we have gathered at the commission, there's little evidence that the real time pricing in those cases changed the customer usage patterns. Missouri utilities have offered a wide variety of interruptible rates and curtailment programs for industrial and large commercial customers. They range from voluntary programs where the utility calls ahead and offers the customer a price per kilowatt to reduce their load to special contracts where customers are required to reduce their load for compensation. These programs were primarily developed to address load constraints on the system and not for financial reasons.

Ameren UE has been offering interruptible rates for more than 20 years. Since 200, 20 to 25 percent of the customers enrolled in their voluntary curtailment program are actually curtailing when asked.

Aquilla has been successful in getting load reduction when necessary despite having relatively few customers in their program. Ameren UE has been a pilot project on air conditioner recycling the last two summers. Kansas City Power and Light has initiated what I would say are most promising demand response programs on the residential side. They're offering to install a free digital thermostat for customers in exchange for allowing them to cycle their air conditioners during weekdays. Customers can manually override the system with a phone call. Their goal is to have more than 14,000 customers participating in this program by June of next year.

What has our experience taught us? It's taught us that interruptible rates, when they're voluntary, work well for some of the large, sophisticated customers. The key is that the contracts have to be specifically tailored around the customers needs.

Curtailment programs for residential customers can work, but there are several key factors in getting those programs to work. It's important for the utility to know the customers and their usage pattern. AMR is key for that. Making sure that when you're depending on that technology, it had better work. Because if you have a pilot program, and the technology fails, it's extremely difficult to get those customers to come back and participate in a new program.

In terms of the customers themselves, there's been some discussion about what customers want. My experience with customers in our state is they want to know what's in it for them. If they participate in a program, they're going to want to know what they can save and they're going to want to be able to verify that amount. It's extremely difficult to motivate people to change their consumption habits. The price threshold necessary to change their behavior appears to be fairly high. We have to make it easy for them to participate in the program.

One of the attractive things about Kansas City Power and Lights' program is, once somebody signs up for the program, the utility will come out, install their equipment and the customer can manually override the system with a phone call.

In terms of barriers that are out there, in terms of the interruptible rates, reliability is a concern for a lot of our large industrial consumers. We had a lead smelter a few years ago that was very close to signing an interruptible rate contract when they were in financial distress. The price of lead went up. They tore the contract up and never came back to the commission.

Economics is key when you're dealing with business. If they can make money, they're going to try to make money when the sun's shining.

Last, but not least, in terms of the role of demand resources in regional planning, we are on the seam between MISO and ESPP. We have the rural electric co-ops in between. We, as a commission, probably need to do a better job of promoting cooperation between the investor-owned and the rural electric co-ops in terms of demand response as part of resource planning. It's been our experience that without a requirement to include demand side resources as part of an integrated resource plan the tendency is for utilities to view the resource planning process primarily as an exercise to determine what capacity additions they need.

More over, reduced usage of a product is not generally considered to be part of their business plan and developing expertise in this area has not been seen as a valuable endeavor until recently when it's become more profitable for them to generate revenue through off system sales, which has certainly spurred the demands to conserve for off systems sales.

Thank you.

MR. KATHAN: Thank you, Chairman.

Our next panelist is Kevin Lawless from Xcel Energy. Xcel is actually a three-for. They are providing three different regions from the SPP, from the interior West and from the MISO area. I was interested in having Xcel involved because they're one of the largest providers of demand response historically and their participation now in MISO. I would like to understand how that might have changed things in terms of their interest in demand response.

MR. LAWLESS: Thank you, David, for your comments.

We are one of the nation's largest gas and electric utilities. We serve much of the central part of the country from states spanning from the Canadian border to the Mexican border, from the Rockies to the Great Lakes. We have over 5 million customers. We have a very diverse fleet of plants. We're the second largest purchaser of wind power in the country. Soon to be the first.

We're executing a $2 billion repowering of metro plants in both Denver and the Minneapolis twin cities area, which is going to reduce emission rates from those plants by over 95 percent while giving us some extra capacity.

As David said, we've been running demand side -- demand response type programs for a long time. We've spent over $700 million in our northern states power territories since 1990. This year we also announced $196 million plan for Colorado over five years. We will be spending upwards of $70 million across our territory in 2006. The way I like to think about it, demand side activities, demand response, energy efficiency programs are much like building your individual retirement account. Continued, constant investment, early investment pays off in the long run. That's what we've done and that's what we continue to do.

We run a load control program with over 350,000 customers participating. We continue to add 20 to 30,000 customers a year. One of the more exciting things there is we have a new technology we're implementing there, which is increasing the capability we get out of that system by over 30 percent without changing the customer base.

Customers, from our standpoint, are all about cost and they're all about choice. What we've tried to do is give them choices to control their costs. That's what the range of our programs have been. From the efficiency standpoint, we give them the capability to see incentives to help them invest in longer term things like changing their systems, changing their appliances, whatever it may be, for the class of customers involved. But we also have the shorter term options where, for instance, economic dispatch of some of our pricing programs is now very real.

In the last few years we have changed in conjunction with the Minnesota Commission. The criteria on which we operate our load control programs from basically a reliability measure to it be economically dispatched as well. From our standpoint, the biggest challenge around this, and one that we feel at some level we've been successful over the years, is making demand activities, giving them a competitive return to generation and transmission activities. This is not just a sales program. It's not something that we just do out of the goodness of our heart. But this has to be, if it's going to be truly successful for everybody across the country, it has to be something that can earn a competitive return for utilities, particularly those of us who are in a regulated retail environment for the most part.

And, while you're right, we are in three regions and fully participating in the RTOs there, you know, we're still basically regulated at the retail level. That's where we make our money. That's where we need to make sure that we're basically fully compensated for the activities we and our customers are taking charge of. We have other challenges. Technology is obviously a challenge. We have a wide range of legacy programs. Moving customers from the legacy programs to more economically dispatched programs is obviously something we look at very carefully. I think four years ago, when I was here in front of FERC at DOE, we were really worried about whether or not there would be basically destruction of that legacy that we built.

I think now today it's more easily seen that we can make that transition. And, perhaps, I believe that transition is going to take place more slowly than we were looking at four years ago. We've proposed some different things in some of our rate proceedings recently, including a financial neutrality factor in Minnesota, which should help us recover some of the earnings that we might have earned if we invested in generation plants.

We've proposed a time differentiated fuel clause. Because, as the fuel costs become larger and larger, that becomes a bigger part of our costs. Rather than having an overall average rate of fuel, looking at some time differentiation there, will help us send the right price signals. We've looked at more mandatory time of use. In fact, over 500 kilowatt customers we've proposed beyond mandatory rates in Minnesota.

Relative to the RTOs, we continue to work with them. Frankly, I think, relative to demand response, we're still in a time of infancy relative to the RTOs in the areas we serve and we have a lot of work to do with them in that regard. But, basically, we have a lot of, I think, very basic issues in terms of cost from the ISOs coming through into the retail-regulated markets and how the commissions view those. And I think one of the biggest challenges we all have is assuring that there's FERC, RTO, state commission utility interaction in a way that's going to create a positive win/wins for everybody.

Thank you.

MR. KATHAN: Thank you.

Moving on to Texas, we have Commissioner Barry Smitherman.

MR. SMITHERMAN: Thank you for the opportunity to be here, Mr. Chairman. I like your coffee cup.

(Laughter.)

MR. KELIHER: Bigger than the usual coffee cup.

(Laughter.)

MR. SMITHERMAN: Appropriately so.

In the ERCOT market, which is approximately 85 percent of the load in Texas, as you all know, we have a competitive wholesale and retail market that has resulted in bilateral contracts for most, if not all, of the supply. We like to believe that these contracts between generator rep to customer really have facilitated creativity. The type of creativity in load response and real time pricing that I think you all are considering.

Antidotally, our system operator says that the time of peak demand in the afternoon in August, in our market, has shifted ever so slightly. We believe that is a result of buyers and sellers negotiating to move off of that very expensive peak time in the residential market. In the last legislative session, House Bill 2129, put in place the mechanisms for advanced metering. For example, TXU is rolling out approximately 500,000 meters a year. They'll do that until they get all three million of their residential customers facilitated. The cost is approximately $150 a meter. We heard this morning $123 on the low end and $150 on the top. That's a non-bypassable charge that's facilitated by the TDU, the transmission and distribution utility.

We think this is going to give reps a lot of information about both profiling and allow them to customize products for residential customers that they presently don't have. In addition, a complimentary product whose result remains to be seen, was the implementation of broadband over power line. We had a bill last legislative session that permits utilities to facilitate and we think there will be some creative coupling and integration between smart, advanced metering and PBL that may results in outcomes that we really cannot anticipate in terms of customer response.

We continue to have our LAAR, our load acting as resource, which is about half of our responsive reserve. That is part of the two-step ERCOT four-step curtailment plan. If selected, a LAAR is paid the market clearing price for capacity. As you know, ERCOT is an energy-only market. The commission has decided to remain an energy-only market.

And, in the context of that, we're presently undertaking a resource adequacy rule. That encompasses price responsiveness of load really on a footing equal to resource adequacy and transmission adequacy, and we've received significant comments along that line.

In terms of transmission, I recall that there were questions about whether this has an effect on transmission and how do we integrate transmission investment with load response. We have not had a challenge with transmission deployment in the ERCOT market. We've spent about $2.8 million over the last three to five years on transmission and we have about 2.3 million on the drawing board today.

What is interesting is that going forward we believe that economics will play as much, if not more, of a role in here we site transmission infrastructure as reliability and congestion management has in the past. In the Q&A I'd be happy to explore any of these further.

Thank you for the opportunity.

MR. KATHAN: Thank you very much.

We're going to move on to the Pacific Northwest. Northwestern Power and Conservation Council. I have to keep on stopping myself because it used to be known as Northwest Power Planning Commission.

MR. CORUM: I work for the Northwest Power and

Conservation Council. We're an interstate compact made up of the four Pacific Northwest states -- Washington, Oregon, Idaho and Montana. We are new to demand response as it is being discussed here I would say. That is primarily because, historically, we've had the benefit of a very large and very efficient hydroelectric system that provided, at one point, 80 to 90 percent of our energy. That's changing. The hydro system's pretty much built out and we continue to grow so that now it depends on the year because the river doesn't have the same amount of water in it every year. But something over 50 percent of our electricity is still provided by the hydro system. So it's important but becoming less so.

A little bit more background. We have some very large transmission links with California which affect our situation. We shared the California crisis with California because pretty much the whole time their spot prices were our spot prices. We made modest steps toward retail access. I would guess that something like 10 to 15 percent of our load might have choice in Montana and some customers in Oregon have access to retail choice. We have no ISO. A long story. The short story is we don't have an ISO yet and I'm not clear when we may ever, and we are somewhat surplus in generation at the moment, which makes selling DR a little bit tougher because we're a pretty reliable system at the moment. We're trying to think long-term, but there is not a great deal of immediate urgency felt by anybody.

Certain utilities have used what we have called "demand exchange" programs generally, which are Day Ahead bidding programs. Those, I think, were fairly successful when the spot prices warranted participation. There's not a lot of participation now. A number of utilities have air conditioning, water heating cycling programs, mostly for summer peaking. The region, as a whole, is winter peaking, but there are parts of the region that are summer peaking and irrigation actually. The load controlling irrigation is a significant factor for some utilities in the eastern part of our region. We've got some pilot programs for rates, but I would say none of them very substantial.

We do have the advantage of having a Pacific Northwest lab in our region. They've been one of the leaders in the grid-wise, smart grid kind of effort. Actually, this isn't the only thing that's going on, but it's the thing that's going on today. There are 50 clothes dryers being installed in Gresham, Oregon being fronted by Portland's General Electric, which have devices in them that allow those dryers to respond to under frequency conditions in the western interconnection. It's a very, very small initial step in making the west-wide transmission system kind of self-healing.

In terms of formal programs, we're probably somewhere north of 200 megawatts right now. That, I think, will grow. But it's not, as I said, a very large thing right now.

In regard to transmission, I think we do have an interesting thing going on in the region. The Bonneville Power Administration owns -- they are the largest owner of high voltage transmission in the region and they've been running a process for a little over two years looking at alternatives to augmentation of their grid. That analysis, as you probably appreciate, is very, very site specific. You need demand response to be right where you need it in order to be able to put off or forego a new installation of the transmission system. But they've actually identified a couple of targets.

There's a substantial pilot going on, on the Olympic Peninsula, in Washington State right now. We have run into problems. I think we talked about the value chain -- both yesterday and today -- of the distribution system, the transmission system, the power system. All benefit from demand response, and pulling those benefits together to help pay for demand response is sometimes a task.

As far as planning goes, the council I work for modeled DR as a super peaker in its last plan put out at the beginning of last year and showed that it reduced both expected costs and risks over the long term, and several of the utilities in their long-term plans have modeled DR as well. I would say, in a pretty effective treatment of DR as an alternative to generation, the things we're working on right now, as I said, we're interested in what works. We're interested in how we can develop this capability at a time when it's clear we don't need to exercise an awful lot of it. But there's the research and development work that we need to have ready to roll these things out when they're actually necessary. We'd like to convert the work that we've done into some kind of cost effectiveness guidance for our regulators and utilities so they can judge what actually makes sense when a utility brings a program into them.

That's it. I think I'm around five minutes. Thank you.

MR. KATHAN: Thank you, Ken.

Our understanding is that Bruce Kaneshiro from the California Public Utilities Commission will be going first to talk about what's happening in California. California is one of the more active states on demand response, so we're eager to hear what's going on.

MR. KANESHIRO: Thanks for the opportunity to participate.

I'd like to start by highlighting our California Energy Action Plan, a roadmap of energy policies that has been articulated by the CPUC in addition to our sister agency, the CEC, as well as the governor. It addresses various energy issues in California of which demand response is one of them.

With respect to demand response, in our energy action plan I think the EAP does two important things. Number one, it sends a message to all of our energy stakeholders that demand response is a top priority of the CPUC and the state. It's listed second only to energy efficiency amongst the various resources in meeting our state's energy needs.

The second thing that the EAP does is it actually has, I believe, 12 specific action items, either to be fulfilled by the investor-owned utilities or by agency staff. I just listed a few of them there such as advanced metering, creating standardized measurement and evaluation mechanisms, et cetera.

Our commission, along with the California Energy Commission, meets on a quarterly basis. We call the EAP meetings in forums such as this where investor-owned utilities as well as agency staff are required to provide updates on these action items.

What have we done to date? I think it started as early as 2001. The CPUC, along with the CEC, started to deploy advanced meters or in-home meters to customers over

200KW in demand and placing those customers on time-of-use rates. In 2003, we've been working with utilities in developing new demand response programs, such as critical peak pricing, demand bidding as well as expanding their emergency trigger programs.

One of the key items of the Energy Action Plan is the adoption of a long-term megawatt goal for the utilities to attain. That is, specifically, by 2007 the utilities will have attained the equivalent of 5 percent of their system peak demand and that will be programs that are dynamic pricing, Day Ahead-triggered programs.

Yesterday you heard a lot about our statewide pricing pilot and the results of that, which is essentially a pilot to explore the demand response capability of residential and small commercial customers. There was some question going into that pilot as to how capable these types of customers were in responding to time-of-use rates or critical peak pricing rates. Those results have been very informative to our agency. Tied to the findings of that SPP pilot are the advanced metering initiatives that you heard about in the previous panel. Each of our largest investor-owned utilities have separate applications for full deployment of advanced metering.

Lastly, I wanted to highlight our resource adequacy requirements that demand response has been incorporated into those and effectively all load-serving entities in our state are required to demonstrated to the CPUC that they've acquired enough load, enough supply to meet their forecasted demand on a yearly basis. Demand response is incorporated into that in that it either counts as a supply side resources or it counts as an adjustment to the LSE's forecasted demand, depending on the type of demand response program it is.

The next few slides I have are the actual programs that we have through the investor-owned utilities. I'm not going to dwell too much on those except to say that we've organized them by programs triggered on a Day Ahead basis, programs triggered on a Day Of basis. We do also have customer education programs and programs that are providing tools for customers to understand how to participate in demand response.

I have one slide here that shows the progress we've made with respect to Day Ahead programs. Currently, as of November 2005, we have about 930 megawatts attributable to Day Ahead programs. The goal for 2007, assuming that system peak demand is about 40 megawatts for the three investor-owned utilities, that would be 5 percent of that is about 2000 megawatts. Basically, we're about halfway there. As I said, it's an aggressive goal. Is it reachable? Commission staff believes it is, but we'll see if it happens.

I'll close by just wrapping up on some of the challenges and barriers that, at least from the CPUC's view, that exist. How do we expand customer participation? How do we effectively meet the goal that we set? What we've been finding from some of our evaluation and monitoring programs, and through some surveys of customers who were either participants or not participants, is that there are misconceptions about demand response that still exist, misunderstandings of some of the basics of energy, misunderstandings or a lack of information about what programs are out there and what tools are available to help them participate.

We're also hearing that some of our demand response programs or dynamic tariffs don't provide enough of an incentive for customers to cover either their fixed or variable costs in participating in these programs, so it's not attractive to them. How do we effectively increase incentives and yet stay within cost effectiveness is a question. We also have a great interest in measuring or verifying the demand response savings that are generated by these programs. I think this issue was highlighted by a previous panel. There really isn't a lot of historical data yet, at least with the price responsive programs. That's making that a challenge. I think that issue is something that I think that has implications with our ISO, perhaps, in the future.

Again, cost effectiveness is something I touched on. And then, specific to California, I think there are some issues with respect to developing critical peak pricing rates. We have a bill that was passed during the energy crisis called AB-1x, effectively, depending on your legal interpretation of the code of the language in that bill, you could interpret it to mean that the commission is prohibited from actually raising the rates for most of its residential customers until the power that was procured by the Department Water Resources has been effectively paid off. That won't happen until 2011. So how does the commission comply with that bill with the ushering in of critical peak pricing rates for residential customers that would come in with the advanced metering?

One interpretation is that if it's voluntary, if we offer CPP rates that are voluntary, that's not a violation of the bill. That's one interpretation. There hasn't been an actual decision yet about that.

And then, with respect to real time pricing, I think the creation of the Day Ahead price will help make that separate tariff viable for large customers.

MR. KATHAN: Thank you, Bruce.

The last panel is Susie Sides from San Diego Gas and Electric.

MS. SIDES: Thank you very much for the invitation to let you know what's going on in San Diego. I think Bruce did a very good job of giving the overview of California. I'd like to spend the next few minutes talking about San Diego and what's happening in our service territory.

We are the smallest of the three electric investor-owned utilities with about 1.3 million customers. So I do appreciate being the smallest one here to be able to talk about what we're doing.

As Bruce mentioned, with the onset of the interval meters that came out in 2003, with that came TOU pricing for those larger customers. Actually, for San Diego, though, we actually provided time-of-use pricing to our customers with demands of 20KW and above back in 1988 and '89 -- before the '90s. So our smaller customers have been on time-of-use pricing since the late '80s.

Most of the programs that are in place now for demand response in California are designed for the larger business customers. Again, those customers with the interval meters, again, 200KW and above. In San Diego, because of the size of our customers, we don't have a large industrial base. We actually allow our customers 20KW and above to participate in those programs. It's very difficult right now to get the communication and the education across, but we do allow some of our smaller customers to participate if they choose to do so.

For San Diego, we have 14 programs that we're actually managing right now. We have four Day Ahead programs and eight Day Of programs. I caution to use the term "economic programs" or "reliability-based" programs because right now in California we don't have a transparent market price. So what we use as a proxy for Day Ahead is temperature, weather and system conditions. So that's something unique, I think, to California.

As Bruce mentioned, for the Energy Action Plan, it's very clear that we have the support of our commission and the California Energy Commission with demand response. That provides a clear signal to the utilities on where we're going with demand response and energy efficiency. The Community Action Plan was actually adopted in late 2003. San Diego actually embraced the loading order in May of 2003. So I want to use an example of how the Energy Act Plan and the loading order actually can be applied.

When we completed our resource plan in 2003, identifying the needs for San Diego, we identified that we needed some end region resources to meet greater reliability needs. So we issued an RFP in May of 2003 to address these issues. We made it very clear in that RFP that we were seeking demand response resources first to meet those needs. Secondly, would be renewable resources, then fossil fuel generation. And, to the extent that we did receive, and were able to negotiate two contracts of an RFP for demand response, it didn't satisfy our total need, so we did need to go to renewables and generation.

But one of the requirements from the RFP for demand response was that these demand response resources needed to have 10-minute dispatch requirements and we were able to get two of those contracts. The challenges behind that was it took a long time to negotiate and work out the contracts. But I can say that those programs are working now. We have one program that's been in place for about year with about 10 megawatts. That's the direct load control type air conditioning type of program.

Another program that's very unique and innovative is what we call "a clean backup generation" program, which allows our customer to use backup generators for demand response. I think that's a clear example of how the Energy Action Plan sets the direction and we followed it.

Also, in California, what's working, as Bruce mentioned, is the statewide pricing pilot. What we found from there a couple of interesting facts. One that I mentioned yesterday. We found with the residential customers who are exposed to both a dynamic rate and also enabling technology such as a programmable communicating thermostat actually reduced demand twice as much as a customer with just the technology alone. Secondly, we found that 80 percent of the load reduction came from 30 percent of the customers.

What are the challenges? Bruce highlighted the challenges. One, we do not have a transparent market price, so we're not able to expose our retail customers to real time pricing signals. A second challenge is AB-1x. As Bruce already mentioned, that is another one. It limits our ability to allow residential customers to participate in demand response.

Finally, looking at program design, which I'm very much involved in, I'd like to say that, if we can make the program simple, sustainable and certain. Simple for customers to understand and for us to implement. Sustainable, knowing that the programs will last and there was some long-term benefit from that and then, certain. We need it from a resource planning standpoint to know that those resources are there when we call on it and that's how we're going to save dollars for both the system and for our customers.

Thank you very much.

MR. KATHAN: Thank you very much.

Before we start the Q&A, I was wondering does the

Chairman have any questions?

(No response.)

MR. KATHAN: I'd like to organize these questions as much as possible. There will be some broad questions across all regions, but I wanted to start off with some region-specific questions. I'd like to start off with the MISO and with the Midwest.

In your comments, Ron, you referred to -- that the energy-only markets comprised short-run reliability function. I wanted to understand a little bit more are you indicating that prices will, without any purchase of any options or purchase of any contracts, will be able to provide that short, 10-minute reserve type of resource?

MR. McNAMARA: I think, first of all, there are issues in our market as there are in others of the RTO markets. We need to make sure that we're sending the right price signals. The right price signal out there, in my opinion, would be one that includes the value of an operating reserve at the very least so your energy price would be energy plus operating reserves. That should then set the market price. That signal needs to get out there as, at the very least, a piece of information. That signal then translates, in terms of information, up and down the chain.

I think demand response should be paid that market signal if they choose to participate in the market in that way. I think we need to make sure that we get the right price signal. I think we need to get the scarcity price signal into the marketplace. And I think then on a voluntary basis we need to make the demand response or price responsive demand can get paid. In many cases, it's our belief that price responsive demand will actually be the one setting that price. They need to make sure that they can price that and I think that will then be reflected in long-term contracts and bilateral contracts that certainly will underpin our market. I think that's what we've seen in Texas and I'll let the commissioner opine on that. But I think that's what we've seen in Texas and we think that's a pretty solid model to go from.

MR. KATHAN: Are you saying that you don't need the type of northeastern ISO type emergency programs in MISO where you actually have participants ready and willing to reduce when needed?

MR. McNAMARA: I think you have to. In our world we're going to have to look at the efficacy of establishing a demand curve, if you will -- an administrative demand curve for operating reserves. In that sense, once you get into a very short timeframe, you're dealing with what we would call a public good in terms of making sure that the lights stay on.

I think that you have to possibly go down that route in terms of actually establishing some mechanism. But I think the first idea is, how do we get the right price signal? Let's see the response from the price signal there and then as a backstop have some sort of command and control. But, at this point, and only for the real time in terms of making sure that you can maintain the reliability of the system.

MR. KATHAN: I'm also somewhat curious about the role of demand resources within the MISO structure because you have the market, but also there is a variety of control area operators. Is the operation of demand response -- is that the responsibility of the actual control area operators or is there a reliability role performed by the MISO?

MR. McNAMARA: I'll speak in terms of the MISO's role, not the control area's role. We certainly allow demand response resources in our Day Ahead market. We have a shared responsibility in terms of the real time reliability with the control area, balancing authority -- responsibility kind of split between us.

One of the things that we are looking at in terms of the efficiency of our market is do we have that split correct and should, and I think, in particular, where we've seen with our stakeholders over the last couple of months, a move toward what would be the benefits and the costs of MISO essentially being responsible for that operating reserve -- that short-term reliability, sole function, which would then put more of that demand response into the MISO purview as opposed to a split level between us and the control areas.

MR. KATHAN: Kevin, you, I believe, are one of the control operators. Do you see -- I think you stated in some of your comments that you didn't see much of a difference.

MR. LAWLESS: I don't think we're yet seeing a lot of difference. Maybe a couple of real life examples would be helpful.

This past summer on June 23rd was our peak day in our control area. We called in our programs. We reduced our peak or forecasted peak by 8.2 percent. I think, in general, that goes over and above sort of the short-term, very short-term reserve we might be looking for in some of these situations. We're still operating, to a great extent, as a vertically integrated utility. I think a second example happened this winter. About a month ago we had a very extreme ice storm in the Dakotas. I think the fact that we had these programs in place basically saved the system at that point in time -- not just our programs, but the other utilities in the area. We were under some very extreme circumstances and just to have the framework of something in place so that we could get the customers very quickly. And, while it's sort of an economic program, it obviously has huge reliability aspects to it. I think those are two examples of how we've been running things now. I think we've still got a long way to go before we fully incorporate the MISO signal into operations.

MR. KATHAN: You're saying then the valuation -- you haven't quite moved to where the existence of the markets that the MISO operates is effecting how you are valuing or viewing your resources.

MR. LAWLESS: As we feed information into the market, we're basically feeding in with what we can do on the demand response side.

MR. KATHAN: As part of your portfolio?

MR. LAWLESS: Right.

MR. KATHAN: Chairman Jeff Davis, have you noticed any difference inside your state, your utilities in being part of MISO at this point?

MR. DAVIS: I think we're experiencing some growing pains. I think it's complex and we have some entities that, even though their utilities are not necessarily -- some of our small municipal utilities are not very sophisticated and they do not have the resources to really participate in the MISO market, so there have been some definite growing pains there that we've been working to try to get those issues resolved.

It's just extremely complex. My impression, from talking with some of our utilities, therefore, there's a lot of details to be worked through and there are some growing pains that are still going to happen.

MR. KATHAN: That, to me, is one of the interesting parts of the Midwest and the MISO is that it's a combination of states that mostly are vertically integrated still with an open market. Trying to understand how things are moving, I think, is something that needs to be observed over time. Do you have any comments on where it may be going.

MR. DAVIS: Obviously, as a state commission we're very concerned abut having our cheap base-load generation siphoned off to serve customers in other states. Our customers paid for that generation and they're entitled to first usage of that generation. So we're very protective of that. Other than that, I'll turn it over to Ron.

(Laughter.)

MR. McNAMARA: You didn't warn me on that.

Again, our position -- we obviously have a very large industrial manufacturing base in our footprint. It's very, very important for us to listen to the needs of those customers. What we're hearing, and it is complex for the smaller person, that's something that we need to overcome and hopefully we'll get the right mix in terms of what people must do versus the ideal state.

But, in terms of the industrial manufacturing base, they're in an increasingly competitive national and international environment and energy costs are certainly a large portion of their costs. We have to be responsive to the needs of that and what we hear is that they want to be able to partake and be involved in a price responsive demand regime and to be able to take the value that they can do for managing their load better and to get assess to that value. We think that's an important component that needs to be built into our market.

MR. LAWLESS: I think, David, from our standpoint, we've got a variety of programs where customers are asked to respond on a 10-minute basis two or three hours ahead of time. We also have on the load control mix -- you know, we basically forewarn customers in a broad way that this looks like this is going to be a control day and you may be in the mix. But I think that bodes well for the future. It's clear customers, given some certainty, given some understanding of the prices, given some choices in terms of how they might respond, and obviously the big guys are different than the residential customers -- you know, as long as there are some choices out there, and they come with a fair amount of certainty -- our customers need to make investments. They can make those investments and recognize that there's likely to be a payback. We're going to be able to make this change and we're going to be able to make this transition from what we have today to something more in line with where MISO and others are headed.

MR. KATHAN: Switching to issues of time-based rates, is there any prospects that there will be more price responsive load or more time-based rates coming up in the Midwest?

MR. LAWLESS: Colorado is not exactly in that footprint, but we are launching that pilot currently -- a residential time-of-use pilot in Colorado. Irrespective of some comments this morning, well-run pilot programs are going to keep us from making very stupid and very expensive mistakes. I do agree there are times where they are delay tactics as well. But, you know, our expectation is that this pilot will give us information we can use across our territory. We're looking at multiple different models of time-of-use rates, critical peak period pricing and so forth. We're doing more of that. As I said earlier, we're implementing more mandatory time-of-use options for our larger customers, and I anticipate over the coming years, as we alter rate designs and rate proceedings, we'll be moving to that across our whole territory. I think we'll see more of it.

We have, in some cases, the metering systems in place to help us do this at some small scale. We don't necessarily have it at a large scale to be able to say -- do hundreds of thousands of customers at a crack yet. We'll probably get there.

MR. DAVIS: I think we'll have more time-of-use programs. I think I want to echo what the witness from San Diego said. The programs have to be simple for people to understand, and it's been our experience that they need to require a minimal amount of effort on the customer's part. It's set up so the utility can control it. The customer can override it. I think those programs work much better than requiring effort on the part of the customers just hasn't seemed to work very well in Missouri. I can echo very strongly that the customers don't like being exposed to real time prices.

MR. McNAMARA: The only thing I would add is, to the extent people want to do that, we'll facilitate it. I would say that customers, rather than talk about costs, we need to talk about the value -- the choice to consume now versus later needs to be reflected in what they're paying and they're going to find that out through having an active and transparent market that establishes that value and I think that's critical here, allowing customers to say what value they're actually providing to the system.

MR. KATHAN: Do any of the staff want to ask any questions of the midwestern representatives?

MS. WHITE: For Xcel. You said you've installed 4000 of those meter for customers for your pilot. Do you want to talk about what they cost? Who paid for them? How advanced they are?

MR. LAWLESS: I don't know that pilot costs are really indicative of the long-run costs. We have a lot going on in that program. We're trying to get a lot more information, obviously, than we might do when we're actually at a real program state. So I think the concern here is not so much what the metering costs is because it's kind of hard to break. In some ways it's not what you want to breakout, but we're really looking for is the cost, getting to the value of what these programs will do and how customers will respond. In that regard, we're spending everything we need to so that we can get to that information.

(Pause.)

MR. KATHAN: Okay. Moving on to Texas. One of the observations, when watching the Texas market for a while, is that there was a significant drop off in the amount of demand resources that happened when restructuring did happen. On the other hand, thee's a lot of nice things that have been said today and yesterday that Texas is the best market. I wonder if you could discuss how that transition happened and what was learned from that and what's the level of the resource at this point?

MR. SMITHERMAN: David, let me say a lot of that happened before I came to the commission, but my understanding is that, for example, with regard to interruptible load tariffs, that we are contemplating our rule -- that would be rule, Section 25186, which would basically say that any non-seasonal load that would have been eligible for interruptible load program back on January 1, 2002 would be considered. We limited that to a pool with an annual demand of about a thousand megawatts. It's an attempt to try to put something similar to what was in place in place now.

Really it's a compliment to our responsive reserve program, half of which, as I discussed earlier, has the LAAR component to it. We are blessed with a very robust reserve margin presently. After we deregulated our wholesale market, we had some 26 gigawatts of new generation installed, none of which went into rate base. We anticipate that between now and 2010 we'll be working some of that off as older, less efficient dirty plants are retired. So the need for demand response has not been critical. It will become more important as we go forward.

Again, we've reiterated our support of an energy-only market. There will be no capacity payments to generators. And, as a result, we've got to facilitate demand response as well as be cognizant of price points. We're considering that as well in our resource adequacy rulemaking.

MR. KATHAN: Just to follow up, when you say "facilitate demand response," what do you exactly mean?

MR. SMITHERMAN: On the residential level, what TXU is doing in north Texas with 500,000 advanced meters a year is a very aggressive program. We expect that will be in place at their current pace in four or five years. The law prohibits us from rolling it out any faster than three years. So we would hope that other TDUs, say, AEP or Sara Point will emulate that program as well. Again, that's for residential customers.

On the industrial side, the antidotal evidence is that bilateral contracts, for the most part, have a component of this in it. They have facilitated, through private contracts, a time of day pricing and seasonal demand pricing. We think that's been reflected in the kind of load shaping that we've seen in the market.

MR. KATHAN: Do customers or competitive retailers have access to the meter data or will they in Texas?

MR. SMITHERMAN: We hope that they will. At this point there are only some 50,000 that have recently been deployed in the TXU area. It's going to be important, obviously, for a competitive market that all the reps have access to the data. I'm not sure we've teased that out completely, but it would certainly seem logical that they would.

MR. KATHAN: Aileen?

MS. RODER: I just wanted to follow-up on a question from earlier today, Commissioner Smitherman, regarding stakeholder input into the process and how that's been working in Texas.

MR. SMITHERMAN: There are really two layers of stakeholder input. One is the ERCOT process itself. The board is comprised of stakeholders, independents as well as the chairman of the PUC and the CEO of ERCOT. That process works in a very collaborative way with regard to protocol revisions. At the commission, when we have a project like our resource adequacy project, which encompasses demand response, that is an open project. We have a number of workshops where all the market participants come. For that one, we've had three workshops as well as giving them generous ability to provide written comments.

MR. KATHAN: Any questions for Commissioner Smitherman?

(No response.)

MR. KATHAN: Ken, I wanted to go a little bit into the Pacific Northwest. The Olympic Peninsula -- I know it's BPA's project, but I wanted to understand. That, to me, is one of the good examples of where demand response can actually be a part of a transmission expansion. Or, at least, allow a delay of expansion and buy some time.

Can you speak a little bit more about that if you can?

MR. CORUM: The Olympic Peninsula looks like a particularly apt example of this. It's basically kind of a radial part of the transmission system. There are, I think, four main lines that run out to the Peninsula. It's not part of the grid. The lines go out and don't go anywhere else and they've got loads growing fairly slow, you know, at a pace that could plausibly be met for several years with some demand response measures. And, to just make it a little bit more attractive, it got some industrial load out there that might not be there forever. So it's not only a prospect of deferring this addition to the transmission system. I mean there's a kind of an option that you get that you might not ever have to build it if you delay it a few years.

Actually, there are some gridwise appliances going out there. There are some directed conservation that has a peak reduction component to it, of course. There's some distributed generation that they've located and I think they've actually exercised the demand response part of it already this winter, but I won't swear to that. I know they did last year. It's a winter peak problem.

MR. KATHAN: Was it a part of the RFP process? Was it anything specific. I'm to focus on this and I'll probably come back to this later.

One of the things Congress has asked us to focus on is the steps to incorporate the demand resources into a -- expansion on an equal basis. I'm trying to explore the steps. Was it a very specific action which they took or was it something that came about.

MR. CORUM: I'm probably not going to represent this absolutely accurately. I can give you the name of the guy to contact at Bonneville who is really the person that knows. This was a kind of specially designed program. It wasn't part of a cycle. But I do know that Bonneville, having separated their power line from their transmission line in response to the initial concerns of Order 888, they're now not bring the business lines back together, but to bring the information of the two planning processes back together because there really are some benefits from some actions that go to both parts of the organization and of course to the distribution companies that are involved as well. They want to get that information, at least, passed in the planning process. The same person, Brian Silverstein, can tell you about that as well.

MR. KATHAN: Thank you. Anything else for the Pacific Northwest.

(No response.)

MR. KATHAN: In California, my major question on California is more on observation. Any comments you want to put on it. If you look at the way California is developing its demand response resources, it's doing it differently than the Northeast. The state is taking a much larger role and is actually requiring or pushing its utilities to develop it as opposed to in the restructured market to the East, the ISO is taking much more of a role.

In California, the ISO does have at least one program, but it's not taking as much of an active role. Why is that? Is that a state policy? Could you speak to that?

MR. KANESHIRO: I think at the CPUC -- it was just identified in 2003 that the commission wanted to take an initiative on. At that time, my understanding was that the California ISO did have two programs in place that were demand response related programs, given the commission's push and aggressive policy position with investor-owned utilities, the California ISO just decided that the commission was going to cover this area, so to speak, thus, I don't recall any controversy over that. That the CPUC was essentially taking a lead role, along with the California Energy Commission and pushing that industrial-owned utility to develop these programs.

So there isn't a state law that directed it or anything else like that. It was just the commission taking its initiative saying that, well, we have the authority over our industrial-owned utilities to push this initiative, to push this policy stance and this is what we're going to do. That's essentially how it evolved.

MS. SIDES: If I could just add to that.

We heard a comment yesterday from the customer from Wal-Mart. I think from the utilities perspective, we have a very close relationship with our end user customers. We believe we have that connectivity to the customer. We can provide them with the information and help them facilitate demand response. So I think being closer to the customer -- how they operate their businesses can help increase the level of demand response. Where I believe at the ISO level they're looking at much larger load levels and aggregate. To participate in the ISO programs, you needed to be one megawatt or greater. In San Diego, that would be very difficult for our customers to do. The utility can help facilitate demand response at a level that I believe the ISO may not have the ability to do.

MR. KATHAN: I guess my question is, is that unique to California? Those are the same issues I would say and most distribution companies would say the same thing, especially when you move to Day Ahead markets and such in California, will things change or will you continue the same kind of state focus?

MR. KANESHIRO: I anticipate a lot more interaction with the ISO as we get closer to that. Will it change in terms of who's taking the lead, I don't anticipate that to change. At least, the two agencies will be working side by side pushing that forward. But I think the state agency will maintain a major role in continuing to push its initiative.

MR. McNAMARA: I'd second that from the ISO prospective. We anticipate, no matter what happens, that the states will retain a great deal of input and responsibility.

MR. KATHAN: Okay.

I'm sorry, Commissioner Kelly, I didn't notice you were here. Do you have any questions you want to ask of the panel?

(No response.)

MR. KATHAN: Thank you.

I wanted to go back to one of the key questions I already indicated to my question to Ken about the participation of demand resources and regional planning and transmission expansion planning. All of you did actually talk briefly on it, but I wanted to talk a little bit more broadly. Where is demand resources in that process in each of your regions? I know that in California it directly is part of it I think you were saying. I'm just curious. For example, in Texas, is demand resources -- is there a state plan that includes that as part of your resource adequacy or are there plans to do that? I know you mentioned you're looking at that issue.

MR. SMITHERMAN: The process for transmission identification and development comes out of the ERCOT stakeholder process. Historically, it has bubbled up from regional planning groups with stakeholders to the extent that they identify a place where we have congestion or perhaps even a reliability issue. That's identified. It's analyzed. It's brought up through the various committees to the ERCOT board.

What we anticipate going forward is that because we put so much transmission in the ground that reliability and congestion management are really not going to be the issues going forward that they have been in the past in spite of our load continuing to grow aggressively. What we want to look at is, what are the economics of putting a particular investment versus generation versus load response. So I could envision, say, down on the Houston ship challenge where we have large air separators, like we heard from earlier this morning, or in east Texas where we have steel mills, that incorporating them into a transmission-planning project and trying to get some understanding of what that demand response might be from a large load would be very important and figuring out whether that is an economically important project or not.

MR. KATHAN: Isn't that going to be a specific process that is being developed? Or do you just want to rely upon market forces to make that decision?

MR. SMITHERMAN: The commission has direct oversight responsibility of ERCOT. We have the ability, if a transmission project is needed, but for whatever reason is not making its way through ERCOT, to interject ourselves into that and put it on the fast track. We have not needed to do that and we may in the future. We have that ability. Everybody knows we have that ability, but we haven't had to use it. MR. KATHAN: Ron?

MR. McNAMARA: I would add, yes, it is part of the planning process as it has been in any utilities' planning process. I think a subsidiary question is how it influences the planning process. It is included. That's where I think we get to the central issue that price matters. At what price do I get -- or if the price is this, what sort of response do I get from the demand side and how has that been translated into a planning outcome or a planning answer? The question is certainly important. Is it included? The answer is yes. The question is, how is it included and how is it differing now that you have a market with transparent prices and so on and how should it be and how is that information interpreted then in terms of building.

MR. KATHAN: I'd be interested. You mentioned you're looking at how to figure out how prices will affect demand and how that will effect planning. I'm interested in seeing how that comes out.

Any other questions?

MS. WHITE: I had a general question.

It's been sort of a theme today -- pilot interaction and coordination between various agencies rules and jurisdictions is really important to make any progress. I'm wondering if there's any confusion on the jurisdiction between all these entities that sometimes erects unintended barriers to additional demand response or advanced metering going forward? Since California and Texas are each their own states, and the next panel, New York whether there are any lessons for other regions that are helpful.

(Pause.)

MR. LAWLESS: I'll go first. Yes.

(Laughter.)

MR. LAWLESS: We're in a state of infancy, I think, with RTOs and how this is all going to work in the long run. I think we're just scrapping the surface right now. We've got a ways to go before we really know how that works. I think with MISO and some of our jurisdictions -- you know, we seem to have some basic -- come to understanding about costs and how they're going to be recovered that, you know, when we're in a situation like that it's very hard to get to how do we design a demand response program. We need to understand that somebody's not going to be left holding the bag, whether it's MISO or whether it's us as a utility.

So there's got to be -- I want to be careful of my words here. There's got to be a common understanding of how it's going to work and how the RTO is going to work. How it's expected to interact with the utility. How it's expected to interact with the state commission. We've got to have all those building blocks in place before we get what I would call "fancy" with designing programs. So, yes, in that sense there is a barrier or a challenge maybe.

MR. McNAMARA: I'd characterize it as a challenge. I'd add we're helped tremendously by the existence of the organization of MISO states to have those discussions and to hopefully come to some consensus on that. I also think that one size need not fit all or necessarily needs to fit all. You have to have plans that are flexible across different stages of evolution in terms of the market, the politics and everything. You can't just have one size fits all. I think certainly in our region we're looking at something that facilitates on a wider, maybe several different options.

MR. LAWLESS: I don't think it's a thing, and I just want to make sure Ron doesn't take my comments wrong. It's not that we're fighting, per say. It's that I don't think we've got all common ground in place to fully move ahead.

MR. KATHAN: Susie, you had a comment?

MS. SIDES: I think for California the collaborative process we've had in place for the last three years has worked very well for us. The California Public Utilities Commission along with the California Energy Commission has facilitated workshops on demand response. Going back to what we talked about with the Energy Action Plan, it's very clear the direction from the Public Utilities Commission, and knowing that the EAP, is a collaborative vision statement from all the state agencies, and it's again very clear. I think the process has worked very well.

I look forward to working with the Cal ISO as we go forward.

MR. KATHAN: Anything else from any of the panelists.

(No response.)

MR. KATHAN: Why don't we go ahead and break. We're going to take a break for 15 minutes. Please come back at 3:45 p.m. Our next panel will be another regional panel. This one focused on the northeastern and Mid-Atlantic PJM areas.

Thank you.

(Recess.)

MR. KATHAN: Welcome back.

This is the last panel at the end of a long day. And, in a sense, we've save the best for last. In a sense, it's the same set of issues that we were asking and were interested in from the previous panel.

We were asked by Congress to look at demand response on a regional level. We have here three of the regions that have done a lot on demand response and wanted to drill down into some of the successes, some of the activities and some of the challenges and barriers that remain or possibly are coming up. And so a similar drill that we did for the last. We're going to go through the full set of panelists, then come back and ask questions on each of the regions.

Why don't we start with Henry Yoshimura with the ISO New England?

MR. YOSHIMURA: Thank you. Good afternoon.

I'm Henry Yoshimura, the manager of demand response at ISO New England. I'm pleased to be here to report to the Commission on the ISO's experience with development of demand response in New England and efforts to integrate demand response into the region's electricity markets. The ISO strongly supports demand response because it improves reliability of the bulk power system and improves the efficiency of the competitive electricity market, which, in turn, benefits all customers in the New England region.

It is useful to classify demand response into two broad categories -- reliability-based and price-based. I think we've all heard a lot about that earlier today. Reliability-based demand response consist of customers reducing consumption in response to ISO actions to manage real time bulk power system operations. On the other hand, price-based demand response consist of customers adjusting consumption voluntarily in response to changing wholesale electricity prices.

Demand response that is centrally controlled, that is, dispatchable by the ISO provides capacity resources that addresses contingencies on the bulk power system. That is, it improves system reliability. Price responsive demand, on the other hand, reduces price volatility in the wholesale market, which, in turn, reduces overall wholesale power costs which reduces the need for regulatory interventions such as price caps and market mitigation.

Both reliability and price-based demand response can defer the need for additional capacity. Demand response resources are integrated into New England's regional system planning process. Reliability-based demand response resources are modeled as generation resources in the system plan and are taken into account when determining loss of load expectations and installed capacity requirement. Price responsive demand, on the hand, is modeled into the system plan as a reduction in demand, which reduces the ISO's load forecast similar to that of the effects of energy efficiency on the load forecast.

The availability of a resource when needed, the magnitude sustainability and reliability of the response, the ability to monitor and control the resource in real time are all factors that affect the development of demand response as a reliability resource. Individual demand response resources can be small and disbursed, so symmetry requirements can be cost prohibitive.

On the price responsive front, the most significant barrier to development of price responsive demand is the lack of a pricing with customers. Wholesale and retail electricity markets are disconnected. Currently, none of the New England states required default service to be priced on the dynamic basis, though there are discussions ongoing among the states and with the ISO on improving that. The flat price design of default service gives customers and suppliers no incentive to respond during periods of high prices or to install advanced metering and control technology.

Demand response programs have been implemented by the ISO as a transitional tool until more effective market mechanisms are in place. ISO has implemented real time and Day Ahead programs where customers response to prices. The ISO has also implemented real time demand response programs, including short-term solutions for southwest Connecticut and the winter 2005-2006 where customers respond to reliability events declared by the ISO.

ISO is also working to implement a pilot program approved by the Commission in November 2005 to assess the effectiveness of demand response resources providing operating reserves. ISO believes that truly competitive electricity markets require active demand response. Our experience with reliability-based programs in New England demonstrates that demand response resources become available when they are properly valued. ISO has successfully attracted, within a very short period of time, several hundred megawatts of demand response resources to address reliability concerns for both summer and winter operations.

To better capture reliability-based demand response, ISO is working to implement capacity and ancillary service markets to provide market signals for investment in these types of resources and to enable full participation by demand response resources in these markets. Development of price responsive demand depends on creating linkages between wholesale and retail electricity markets. To better capture price responsive demand, ISO recommends that states implement dynamic retail pricing, as we have spoken about earlier today, and that's basically retail prices linked to locational energy and capacity prices, and also to implement associated advanced metering billing systems and customer education programs to provide customers with the tools to help control their energy costs.

That concludes my opening comments and I'll welcome questions.

MR. KATHAN: Thank you, Henry.

Our next panelist is Commissioner Anne George from the Connecticut Department of Public Utility Control. Thank you for being here. Go ahead.

MS. GEORGE: Good afternoon. Thank you for having me.

I am here as an individual commissioner from Connecticut, but also as a representative from the New England Conference of Public Utility Commissioners. So I'll give some general comments from NECPUC and then some specific comments from my Connecticut perspective.

Some people like to refer to us up in New England as cranky yankees and we are sometimes cranky. But one of the things that the states have all come together on is demand response and we clearly see this as something that should be a big part of our planning process and our market rules.

NECPUC supports market rules that provide incentives for demand response. We have been actively working with ISO and other stakeholders in the region to come up with ISO rules to recognize demand response. Actually, in the past several years we worked on the New England Demand Response Initiative. And, in the more immediate past, we have been focused on trying to ensure appropriate recognition for demand response in any capacity market structure.

NECPUC believes that demand response should be counted as a resource for regional planning purposes. The role of demand response should receive greater emphasis in regional system planning. That includes emphasis and calculation in installed capacity calculations because that serves as the basis for any resource adequacy mechanism. We really need a balanced portfolio. Resources in New England, including generation transmission and demand side resources.

Demand response should be broadly defined to include energy efficiency properly monitored, and verified efficiency measures provide similar benefits as load reduction.

We want to work with ISO to integrate all forms of demand response in wholesale markets to induce capital investments. I want to stress demand response is not just a retail market mechanism, but a wholesale one as well.

New England, as Henry mentioned, basically has two types of demand response. The resources that get turned on when ISO implements special operating procedures and resources that can adjust their usage in response to raising prices in the wholesale market.

With regard Connecticut-specific activities, Connecticut has been a strong proponent of demand response for many years. Most of the demand response in New England is concentrated in southwest Connecticut, which, as Commissioner Brownell likes to say, is not surprising since it's one of the most congested regions in the country.

We do have an energy plan in Connecticut that focuses on demand side resources. Demand response playing a key role in the state's energy plan. We consider it on an equal footing as transmission upgrades, new generation and we've had greater emphasis in the past on demand response in our energy plan. Connecticut enrollment ISO New England programs, I think, comprises -- and Henry might have the specific numbers -- approximately 50 percent of the total New England enrollment. We have worked hard to get our utilities involved with enrolling customers and we recently approved near term measures to address some of our congestion charges in the state. Those measures include additional load curtailment measures, programs to replace equipment with more energy efficiency models, additional support for customers enrolling in ISO demand response programs. These near term programs should reduce peak demand in Connecticut by 43 megawatts.

There is recent interest on the part of the State of Connecticut to participate in the New England Demand Response Initiative. The state operates 87 agencies and an excess of 5000 buildings. Participation by state agencies has the potential to yield significant demand response. We see this as a lead-by-example and the governor is fully supportive of the state agency taking a big role in this. There's new law in Connecticut called the Energy Independence Act. That requires mandatory time-of-use rates for commercial and industrial customers over 350KW and optional time-of-use rates for other customers. It also requires mandatory seasonal rates for all customers by Spring 2007.

In terms of the barriers we've seen, we have had some initial problems with lack of support from our energy conservation and management board and the utility in terms of how to spend the system benefit charge -- the funds collected from that. I think a lot of that was centered around not understanding demand response as a permanent tool. It was seen as more of a temporary tool. So we're working with them and getting beyond that I think.

There were some earlier barriers with some potential problems with enrolling customers in the ISO New England programs. We've worked beyond those, but those were some of the barriers that were presented. I think we've worked beyond them.

Thank you.

MR. KATHAN: Thank you, Anne.

Time Roughan is from National Grid. One of the few people I'm going to give a couple of minutes more because you're a two for. For the next part of this that you represent load in both New England and in New York. I'd like you to talk to both those regions if you can.

MR. ROUGHAN: Thank you, Dave. Thank you very much for allowing me to come and talk about National Grid's experience with customer side resources.

We talk about customer side resources as work we've been doing for many, many years. Just our standard energy efficiency program has been running over 21 years in New England. We recently surpassed a billion dollars in customer rebates. Those programs alone over the last 21 years essentially started from the last big capacity crunch with the Seabrook nuclear power plant delays. Those programs have been slowly but surely modified year over year over year to get more and more efficient.

We're to the point where customers are seeing some $2 billion a year in savings on their electric bill. That was based on estimates before commodity prices went to 15 cents a kilowatt hour this past few months here. Those programs have been designed for all customer classes -- residential, small CNI and large CNI. We have participation by almost two-thirds of our customers in those programs. The most striking aspect of those programs is they've had enough demand reduction that's been evaluated very thoroughly by a lot of outside parties and ourselves -- and I'll get to that in one more second -- to replace the 450 megawatt power plant in New England over 21 years.

So, in terms of demand side resources, these long-term energy efficiency plans are extremely important and we need to continue. We recently got extensions in Massachusetts and Rhode Island to extend them out to 2012 or so. Those are all naturally paid for through system benefit charges. So it's going to be extremely useful. It gives a customer a tool to manage their energy use and also how to manage their whole load profile in general.

Beyond the standard DSM programs, which we still run extensively in New York, we've been running a real time pricing program for about 300 large customers under default rates since 1999. Recently, we were ordered to include another 800 customers -- 500 kilowatts and up -- in that as well. Again, they're seeing the real time pricing unless the get with an ESCO and hedge that product, which some choose to do.

But, again, we can't know the details of these deals because of standards of conduct with just the wires companies in both New York and New England. So we're not allowed to work in the markets to understand or recommend suppliers for customers, but those have been going on for quite some time and are very, very successful.

The use of what I consider the very successful ISO New England programs and to a smaller extent, only because of the different prices available in upstate New York -- Niagara Mohawk. As you know, the old Niagara Mohawk is in upstate New York. So the high capacity, installed capacity charges -- they'll all down in the city as they should be because of the generational needs down there.

In New England, the price response program is something we've been promoting since the ISO first developed these programs. What's unique about the real time price programs, at least for our customers in New England, is that they provide the customers a learning tool where they earn real time credits upon a call. When they hit the trigger price with the ISO and open the window, if you will, the customers can now experiment with things and decide how well they can do demand response. In that way, it provides a very useful learning tool for them to then step into some of the more mandatory programs like the emergency programs that are out there.

Again, these other programs have penalties with them -- the mandatory emergency programs, whereas the voluntary price programs is a program they can get into and work quite well with. We have approximately 10 percent or 300 of our 3000 largest customers -- when I'm talking largest, those customers over 200 kilowatt enrolled in the price program in New England now. Our goal is to enroll 35 percent of those customers in the few year and primarily, especially in this day and age of high commodity prices, this is a tool they have today. Again, because of the high prices, the trigger point is hit frequently. These calls are made very frequently. Customers have this tool today to manage their electric bill and manage their electric flow. It provides them a simply way to learn without a penalty.

Specifically, what we also offer at National Grid are what we call "demand response audits" to help these customers understand how they break down their load, what their peak load curve is comprised of, what equipment is how much of a percentage of that load curve. We also dig into what are their costs internally if they modify that load, change it or shift it to some other time period. These demand response audits are paid for through the system benefits charges we collect in Massachusetts and Rhode Island. Those are done primarily to educate those customers except for a very small number of very, very large customers of very large multi-nationals, as I was reminded yesterday by the woman from Wal-Mart, most of the customers aren't aware of what comprises a peak load. We need to help them understand so they know what the plan is in order to shed load.

Specifically, what National Grid has also started the last four summer and will have a program this summer as well, we're working on targeted demand response projects at the distribution level. In other words, the initial discussion was some years ago similar to what I heard about the Olympic Peninsula. There was an area where a large industrial customer might not have been there. We were debating whether we needed to spend the $3 million and install a subsection transformer or not. We instead embarked on this targeted project.

We enrolled 20 of the largest customers in the area and taught them what they needed to do to shed load when we called. National Grid then pays them separately. The National Grid distribution company pays them separately. Those firms have been somewhat successful and we've been finding out with those programs -- again, those are voluntary as well and we really need to get to more automated control of those programs in order to actually get the load relief we need when we need it.

The long-term maintenance of those programs -- the customers in those programs is key. Customers come and go. Customer facility managers come and go. You set up a plan Year One. Year Three their business has change. They need to do something different. It's a very maintenance intensive project, but it shows real promise as well. That's the way we are looking to see how to use customer side resource to manage load in local distribution. And, potentially, if there is enough, as we understand it, hundreds of kilowatts might be enough. A megawatt or two might be enough. At the transmission level, I think we're talking tens of megawatts at a minimum, if not 50 megawatts or a hundred. Just the magnitude is so much greater.

We need to start at the level where we can get some good results, learn from that and see if we can actually turn that into much larger projects.

Thank you for your time.

MR. KATHAN: Thank you, Tim.

Now turning directly to New York, we'll start off with David Lawrence from the New York ISO.

MR. LAWRENCE; Thanks, Dave. I'd like to thank FERC for the opportunity to provide these comments on our experience with demand response programs in New York.

Since its inception in December 1999, the ISO has provided opportunities for demand response resources to participate in our markets. The ICAP Special Case Resources Program was developed as part of the original market design and allows customers meeting certification requirements to offer unforced capacity to load-serving entities.

A second reliability oriented program, the Emergency Demand Response Program, provides resources and opportunity to earn the greater of $500 a megawatt hour or the prevailing LBMP for curtailments provided when the NYISO calls on them. The Day Ahead demand response program provides retail customers with an opportunity to bid their load curtailment capability into the Day Ahead spot market as supply resources. Customers submit bids by 5:00 a.m., specify the hours and the amount of curtailment they're offering for the next day and the price at which they're willing to curtail.

Currently, there's a bid floor price of $75 per megawatt hour that's in effect. From May 2001 to December 2005, registration has grown from approximately 200 megawatts to 1400 megawatts. The number of end use customers participating has increased from roughly 200 in March of 2002 to currently around 2300 customers. Since the Summer of 2001, the NYISO has activated these emergency response programs, really a total of 11 times and this program performance is fully described in the NYISO's semi-annual response evaluation reports that we submit to FERC.

Moving on to some of the successes, challenges and barriers we see with demand response from the inception of NYISO's programs, the New York State Public Service Commission has been instrumental in assuring that regulated entities offer programs that are consistent with NYISO program designs. In addition, the New York State Energy Research and Development Authority has offered innovative programs to assist program participants with interim metering, load reduction strategies and emergency generator tuneup and emission testing. And New York stakeholders in all the sectors have worked together to craft market rules that are equitable and effective.

The growth of aggregation organizations offering demand response services indicates that demand response can be a viable business model in New York. Roughly have the megawatts in the ICAP SCR program are currently registered with aggregation organizations. The growth of program registration in all programs indicates that these programs can be financially attractive to participants while not placing undue metering and reporting burdens on them.

The program registration and demand resources have performed reliably during events, providing up to 900 megawatts of load reduction and providing a significant load restoration subsequent to the August 2003 blackout and our output of our remaining offline at low conception levels while the electricity was restored to other customers.

With increased demand response program registration, it's necessary to maintain a reasonable balance between program payouts, particularly those related to capacity payments and performance obligations. Lack of familiarity with the specific rules and program aggregators sometimes uneven emphasis on certain program features have sometime resulted in participant expectations that differ from actual program design.

As an example of an ISO's SCR program, the NYISO's SCR program requires that the participants respond when provided two-hour notice. While the NYISO provides a Day Ahead advisory, it might not provide a two hour notice and activate the program if adverse system conditions don't materialize. Some participants have taken action in response to the Day Ahead advisory. Taking two hours is inadequate for their particular response and suggest they be paid for their actions in response to the advisory. Such actions blunt the operational effectiveness of the program and create an unfair playing field for those resources that can respond within two hours. We will work with aggregators to ensure that participants are capable with complying with all these program requirements.

Another challenge faced by demand response programs is the need to design programs that balance the capabilities of emergency backup generators with environmental consequences. The NYISO firmly believes that the fleet of emergency backup resources should not participate in economic demand response programs unless they carry the environmental permits required of regularly operating resources. Future economic program designs will need to take into account environmental requirements that are likely to be imposed based on the vintage of equipment that may participant.

In contrast, the NYISO would like to see the quick response of emergency backup generation be allowed to participate in programs designed to maintain system reliability as long as these resources are used infrequently.

Finally, on the topic of the role of demand response resources in regional planning, the New York State Reliability Council performs an annual study to determine the install capacity requirements for the New York control area. As part of the study, both EDRP and SCR resources are modeled. The study for the 2006-2007 period is reaching completion. The approved study from last year assumed 975 megawatts of SCR, 299 megawatts of EDRP resources.

Also, the NYISO's comprehensive reliability planning process recognizes contributions that demand response can provide to the planning process overall. Existing planning and demand response programs are factored into the annual reliability needs assessments. The results of many of these assessments indicate a reliability need exists, both market-based and regulated-demand responses will be considered along with new generation or transmission options. The NYISO is currently in its first year of experience with this comprehensive reliability planning process.

We're looking to develop measures that will establish milestones and timetables to track progress for new demand response options.

Thank you.

MR. KATHAN: Thank you, David.

Staying in New York, moving to one of the biggest load pockets in the country, let's hear from Richard Miller from Consolidated Edison. It's been a long day.

MR. MILLER: Con Edison is a strong supporter of energy efficiency and demand response. It's been an active participant in the development of these NYISO programs. I'm pleased to hear today that they're very popular with the customers because I think that's what counts the most and I'm please to be here today to talk about more specific demand response programs that are going on in our service territory.

First, as just a background into discussion of the specific demand response programs that are going on in our service territory now, it's important to think about Con Edison's position as a utility in a restructured electricity market. Con Edison has completely divested its electric generation, except for a small amount of co-generation associated with units that provide steam for its steam system customers. It's no longer in the generation business and doesn't provide commodity services for approximately 50 percent of the load in its service territory.

In Con Edison's service territory there are currently nine retail suppliers. This is not the total number, but there are nine retail suppliers that individually provide around 200 megawatts or more of load to retail customers in New York. As part of the restructuring, the responsibility for demand management related to generation was transferred to state authority, the New York Energy Research and Development Authority, that Dave Lawrence mentioned, so that DSM programs can be made available without any real or perceived disadvantage to any competitive supplier. Con Edison's own demand management programs, other than helping out with the administration of the NYISO programs are related to T&D infrastructure, offsetting or deferring T&D investment.

Finally, I'd just like to note that reduction -- since this is a topic that came up earlier in the discussion and is a topic to be considered -- reduction in load and associated lost revenues were considered as part of our most recent electric rate plan and our view is that we now have no financial disincentive at all under this rate plan. We were especially encouraged by the positive incentives that I will discuss shortly.

The rate plan that I would like to discuss today was entered into in April of last year. It covers a three-year period of April 2005 to April 2008. The goal under this plan is to achieve 675 megawatts of energy efficiency distributed generation and load management, collectively referred to as the demand management over the next three years. The agreement at the time it was entered into projected 530 megawatts. Thirty-five megawatts in demand growth from the summer of 2005 through 2008. The latest forecast shows growth to be 650 megawatts over this period, but we still have a goal that basically matches the demand growth in the service territory matching what I discussed earlier.

It's only 150 megawatts of this projected demand management and energy efficiency that is suppose to come from Con Edison. That's from its targeted demand side program to offset or defer T&D investment. Most of the remainder of 450 megawatts comes from NYCRTA, which implements, as I said before, the state's generation related energy efficiency programs. We're looking then to an incremental 75 megawatts from the SCR and EDRP programs that they've launched described. I also note that for Con Edison's distribution reliability we have our own equivalents to these EDRP and SCR programs. Those also count.

The total amount of money committed over the next three years is approximately $435 million. There's a substantial financial commitment behind this goal of achieving 675 megawatts. Under the rate plan, we're entitled to recover all the direct costs of any demand management program that we implement, the lost revenues from demand management that are incremental to what are already contained in our electric rate plan forecast and urban incentive, as I said earlier, for the megawatt reductions achieved. The incentive amount is $22,500 a megawatt.

In conclusion, I would just note that in terms of keeping the company revenue neutral a revenue decoupling mechanism was explicitly raised and discussed at the time when these demand management programs -- their implementation was being discussed. It was opposed by the company and rejected by the Public Service Commission. It basically found that all the goals, and we agreed with this, of providing the right financial incentives can be achieved without a revenue decoupling mechanism and that a revenue decoupling mechanism has numerous downsides.

Finally, that trying to design one that could account for all these downsides would probably be a near impossible task.

Thank you very much.

MR. KATHAN: Thank you, Richard.

The last region to talk will the PJM region. Probably with a focus on the Mid-Atlantic portion of PJM.

Before Jeff talks, I just want to note that PJM is an active participant in the Mid-Atlantic distributed resources initiative, which Commissioner Morgan will be talking about in a few moments. I just wanted to note that this is a current active activity that I think has a lot of potential.

Go ahead, Jeff.

MR. BLADEN: Thank you, David.

Good afternoon. My name is Jeff Bladen, General Manager of Market Strategy at PJM. You'll forgive that I'm a bit hoarse today as I'm carrying the cold that my daughters have decided to give to me intermittently for the last three years.

(Laughter.)

MR. BLADEN: PJM is very happy today to have an opportunity to participate and to provide our perspective on certain of the issues raised by the questions and at this conference. We worked well with this commission, state commissions and our membership, we believe, to move demand response in PJM beyond programs and, instead, make them an integral part of the marketplace that we're responsible for, including capacity energy and ancillary services.

To that end, I'm going to try today in my testimony to answer the questions relatively directly that you posed, both in light of what's going on and what we're looking towards the future to implement. In terms of status of demand response programs as we like to think of them as products or market elements in PJM, in 2005 we've undertaken a relatively substantial effort to expand opportunities for price-based demand response in our markets. We filed with this Commission recently three significant demand response market initiatives that have a broad stakeholder support which is very, very encouraging. These include integration and permanent status, economic response is a market element, opportunities for demand response to provide synchronized reserves and regulation and enhancements to our participation of demand response in emergency events.

We actually believe at this point, assuming approval and implementation, that PJM will be the first RTO to fully integrate demand response into the ancillary services market. This goes beyond just about anything we've seen in other parts of the U.S. or even parts of the world.

As of today, PJM has three primarily demand respond products. The first of those three is an emergency load response opportunity. It's basically design to provide end user customers an ability to be compensated by PJM for voluntarily reducing load during an emergency event. That's based on the energy that they provide to the grid. That program is directed by PJM so customers respond when directed by PJM.

The second of the three main products is the PJM economic load response program. It's designed to provide access to PJM's Day Ahead and spot energy markets to curtailable loads through an agent member of PJM. LERP participants provide schedule information in real time. They provide bid information to PJM so they can dispatch the load reductions in real time or, in fact, offer load reduction in our Day Ahead market. It's worth noting that in the 12 months just past participating in the economic load response program has grown substantially. We've had about a doubling of megawatt participating, meaning about two times as many megawatt hours were dispatched from demand response in 2005 as were in 2004. In fact, we've had about a fivefold increase in the dollar payouts to demand responsive loads in 2005 versus 2004. We think that's a pretty good sign of progress.

Lastly, the third and certainly important and longest lived product in PJM's demand response portfolio is what's known as "active load management." That's, in fact, an opportunity for demand responsive loads to participate in PJM's capacity market. Basically, loads can be directed by PJM to curtail, and in return they are given capacity credits.

In terms of successes, I've already mentioned the real growth we've seen in the last year, so I won't speak to that again. But there are some challenges I think we'd like to see addressed. Chief among them is the real challenge of bridging spot market, hourly-priced wholesale markets with much longer term retail contract prices, which is what end users generally see. We're not here to say that there's anything wrong with end users hedging themselves with long-term prices. In fact, that's the sign of a well functioning market. What's key, however, is that end users have the ability to sell those hedges. In fact, that's what PJM's economic load response product is designed to do -- to give the end users the ability to take the hedges they've entered into and to sell them when, in fact, the value of the hedge is worth more to the marketplace than it is to the end user. That's a key market element we think the Commission ought to be very aware of.

I would also add that we don't believe, at this point, that sufficient demand response for a well-functioning, efficient market can ultimately be achieved without interval or hourly or better metering installed in a much broader base of customers. We think at the end of the day you have to be able to measure demand response at the same increments as you're measuring supply. Until those two are fungible with one another, you're simply not going to get enough of what you need.

You asked us to speak to regional planning -- to long-term planning. In terms of planning today, demand resources in PJM have generally provided about 1 to 3 percent of PJM's total capacity obligation. In 2005, that represented about a 2 gigawatt reduction in the pool's resource requirement. That's substantial and that comes through this capacity product I mentioned earlier.

In terms of long-term transmission grid planning, demand response is implicitly built into the process through the load-planning process whereby expectations for demand response capability, particularly this capacity capablity, is removed from the forecasted loads before, in fact, transmission planning is undertaken. Thus, we have an expectation of continued participation for demand side capacity much in the same way we have an expectation of the generator continuing to be there and therefore we plan the transmission grid accordingly.

However, it's probably worth noting that, as we work towards future enhancement to the grid, we do not take into account unknown demand response capability. In fact, as part of our desire to enhance our long-term planning process, we're certainly willing to entertain that along with long-term enhancements on the supply side. We think all resources ought to be considered as part of that process. It's just a question of how you design the process.

Let me note that at this point in time, basically, PJM's role is to facilitate the market and that we can order transmission upgrades only when the market fails. That's the last resort.

I'll leave you -- I know my time is up. I'm going to leave you with one last thought. There are really four components to make this work. You've got to get the price right and you've got to have access to the market and users have to be able to sell their hedges and they have to be able to measure the performance.

Thank you.

MR. KATHAN: Thank you, Jeff.

Our next panelist is Commissioner Richard Morgan from the D.C. Public Service Commission.

MR. MORGAN: Thanks, David.

Good afternoon. I'm Rich Morgan, Commission of the Public Service Commission of the District of Columbia, speaking on behalf of the Mid-Atlantic Distributive Resources Initiative known as MADRI.

I want to begin with some comments on why I, as a utility regulator, think that demand response is an idea whose time as come. DR is an essential component of a competitive electricity market. A supply curve without a demand curve is akin to one-hand clapping. That means that when the supplies are tight the generators hold all the cards as we witnessed in California a few years ago. And a sloping demand curve is actually a potent weapon against generation market power and price spikes.

DR offers a long list of other potential benefits that we've been hearing about today, such as operational savings, improved grid reliability, improved customer options and environmental benefits. But there are also formitable barriers that stand in the way of deployment of DR, such as the jurisdictional split between retail and wholesale markets, traditional rate designs that blend costs and dampen price signals, a ratemaking formula that rewards maximization of through-put, and particularly in our region a generation surplus that leaves little value associated with curtailing loads.

Finally, what we call the "fractured value chain," which is associated with unbundled competitive markets. As Chuck Goldman explained this morning, no single entity in an unbundled market has an incentive to pursue the benefits of DR, so we have to pice together benefits from different sources. It's this dicotome between the potential benefits of DR and these formitable barriers that have inspired the creation of MADRI in our region.

MADRI is a collaborative effort of state PUCs, federal agencies and the PJM interconnection. It includes five state commissions from the original PJM footprint, and those are Delaware, D.C., Maryland, Pennsylvania and New Jersey, along with DOE, EPA and FERC. MADRI's goal is to remove institutional barriers that stand in the way of realizing the benefits of distributed energy resources, which is defined by MADRI to include demand response, distributed generation and energy efficiency.

MADRI has no office, no staff and no budget. It's just a commitment by a group of state, federal and regional decisionmakers to work together to solve problems. We feel that we've made a lot of progress in less than two years since MADRI was formed. We've enhanced coordination of our states as well as with the federal government and PJM, and we've moved the ball forward on both technical and policy issues.

MADRI's heavy lifting is done by a working group which meets about every six to eight weeks. This consists of mostly commission staff, staffs of other state agencies as well as a variety of stakeholder representatives. They work with our MADRI policy advisors whose services are provided courtesy of DOE. A couple of those advisors are here today -- Brad Johnson and Wayne Shirley -- who many of you know.

MADRI is overseen by a steering committee that consists of five PUC commissioners and well as representatives from the federal agencies and PJM. Our emphasis is on providing decisionmakers with strategic data and analysis as well as with actionable items such as model rules and regulatory mechanisms.

MADRI is organized around five focus areas and I want to highlight three of those which are directly related to demand response. The first is the development of advanced metering tools. PUCs need to be acquainted with cutting edge, smart metering technologies. But, more importantly, with the policy implications of those technologies -- we held a workshop last spring where we brought in experts from across the U.S. and Canada. We turned that into a website that we call our "AMI toolbox."

Second, we're focusing on enhancing the business case for demand response, which involves assembly of the first set of benefits and getting those numbers to add up can be a real challenge given that fractured value chain associated with demand response. We're working to identify the unmonitized benefits of DR, including benefits associated with the distribution system and with mitigating price spikes.

Third, we are looking at the removal of regulatory barriers at the state level that prevent the benefits of DR from being achieved, such as replacing traditional rate designs with dynamic pricing and also tweaking the ratemaking formula with a revenue stability mechanism to remove the utilities incentive to maximize sales. We're now delivering those tools through a series of onsight briefings of the state commissions, which we began earlier this month.

The need for demand response in this region was driven home by a couple of events last year. We had a rude awakening on July 27th where we had a convergence of weather and system conditions that left us with a capacity shortage in the eastern portion of PJM and we had our first voltage reduction in many years. Indeed, we do have system constraints in some areas of PJM that can enhance the potential value of DR as a resource.

Another surprise last year was a sudden shutdown of the Potomac River plant just across the river from here in August related to environmental concerns. Fortunately, DOE and FERC have stepped in to make sure we keep the lights on in the downtown Washington area while we pursue a more permanent solution. The DOE's order has reminded us that we should be thinking of DR as a resource to help alleviate crises like this.

In conclusion, I want to mention a couple of factors that have made the MADRI approach effective. Certainly, one is the active participation by four types of entities -- the state PUCs, federal agencies, our RTO, the PJM interconnection and a number of different stakeholders. Secondly, the focus on actionable results and putting them in the hands of decisionmakers.

MADRI still has a lot of work ahead of us. We know there aren't any easy answers, but we're convinced we have the right people in the room and they have a strong commitment to getting results. So I'm very optimistic about the prospects for demand response in the Middle Atlantic region.

Thank you.

MR. KATHAN: Thank you, Commissioner.

I'm going to move this direction this time. I'm going to start off with the PJM area and ask some questions. One just as a general comment.

I am very encouraged with the actions and the activities of the MADRI. To me, it's a good indication of the state commissions coming and realizing that there is an issue and working together. I'm looking forward to the results and actually would recommend their AMI toolbox. It's actually a good source of information we will be relying upon as we're developing our metering section.

MR. MORGAN: Should I say what the URL is? It's easy to remember, www.energetics.com/MADRI. It certainly is a resource that is really useful nationwide.

MR. KATHAN: But I want to focus in on a couple of comments. I was struck by the fact that PJM talked about its RTEP. You talked about it differently when you're integrating demand resources than the other two ISOs. Is that a fair characterization that you are basically just reducing an off-the-load curve as opposed to -- I think I'm going to get probably asked more direct questions of the other ISOs. But they sounded like the reliability programs were taken off and considered as a resource.

MR. BLADEN: I can't speak to how they analytically come to their conclusions. I can speak to how PJM does it, which is we look at the expected loads based on a nonrestricted forecast, then we would restrict those forecasts based on expectations for demand response capacity, and those projections are based on our historic performance for demand response.

I think, frankly, from a bottom line perspective, the effect is the same, whether you add it on the resource side or you subtract it from the load side. You get to the same end for how much transmission you would expect to need.

MR. KATHAN: Do I imply from what you're stating that you don't remove the economic resources from that?

MR. BLADEN: We don't today mainly because what we're talking about is a reliability planning process, not an economic one. While, certainly, those economic resources may be there during times of system peak, there's no obligation for them to be there. And, therefore, from a reliability perspective, we have to assume they will not be. Whereas, a generating resource that is a capacity resouce has an obligation to be there during the system peaks if PJM calls them just like a capacity demand response has an obligation to be there. We can only rely on those that have the obligation to be operating or reducing as the case may be in order to reliably plan the transmission grid.

We are certainly open to looking at alternatives for economic resources. But, at this point, given our directives for planning the grid reliably, that's the course we've taken.

MR. KATHAN: I know that you have an economic planning process and, at least according to the tariff, it does have demand resources that are one of the resources that can participate. Has there been any success with any of the demand resources coming in and offering to participate and to relieve that congestion?

MR. BLADEN: In the most recent open windows that were created in the economic transmission planning process, there were, in fact, some demand resources just like there were some supply resources that suggested that they would be trying to deal with that, but we haven't seen that come to fruition. I can't say that we had much success there. We would like to see that work better in the future.

In fact, we have plans this year to substantially expand our transmission planning process to try and deal with some of the experience, the less than stellar experience we had in that process.

MR. KATHAN: So you will be incorporating expansion of that process -- more direct steps, borrowing from Congress' question, you know, to incorporate demand resources?

MR. BLADEN: Obviously, PJM is a stakeholder-driven organization. We're going to work with our stakeholders to try to come up with the best, more robust transmission planning process we can that incorporates any and all resources that are available to deal with the constraints as they're identified.

MR. KATHAN: Staying on PJM -- I'll probably ask a similar question of New York -- we've been hearing, at least antidotically I heard yesterday some complaints from some market participants that there is an issue with payment. That customers who reduced load, I guess, in the economic program last year have still not been paid. I don't know if that's PJM or whether it's New York ISO, but what is that issue and how can we resolve that payment issue?

I'll step back and say I did a report for NARUC four years ago. I raised this as an issue at that point. So I'm curious. Why is this still a problem?

MR. BLADEN: Well, for PJM, in fact, we did have some difficulty having timely payments this year. I think that was mostly a function of the substantial growth we saw this year versus prior years. We had a fivefold increase in the dollars that were paid out. We had a substantial increase in the number of participants that were actually active this year versus prior years. Those growing pains lead us to realize that what we had in place to manage the system was woefully unsatisfactory. What we choose to do in consultation with our stakeholders was to effectively rebuild the systems. We had to manage the system.

Everyone has been paid through this past summer through the most recent settlement period and we do not expect this -- we have rebuilt our system to be far more robust and scaleable.

MR. KATHAN: Aren't there some fundamental issues -- the length of time that the utilities have to provide their metered data?

MR. BLADEN: I think there are two different issues that really you're alluding to. One was a growth issue, which I just described. The other is, in fact, one that will be ongoing one, which is the access to validation data about performance. In fact, there have been some instances, although relatively limited, where data or meter reads that would support performance in our economic load response program have been very delayed coming from the meter reading company, usually the utility.

We're going to look at alternatives to try and deal with that that would expedite that process. But I think, particularly, because of the legacy systems that are in place in many parts of PJM, this is going to be a continuing problem that we'll have to grapple with. I think this ties mostly with the lack of a substantially upgraded metering infrastructure. You've heard plenty about metering today, so I won't repeat any of that.

MR. KATHAN: Commissioner Morgan, speaking of metering and also the related issue of real time pricing or even just time-based pricing, is there any movement besides in the largest customers of New Jersey and Maryland to bring more price responsiveness and more access to meters?

MR. MORGAN: After hearing Alison this morning, I hate to say that we're talking about three more pilots. But, actually, there's one in New Jersey already that's underway. We heard about that yesterday and we have a pilot about to get underway in the District. I know there's discussion about some similar project in Delaware, but I don't have any details on that. We're certainly looking at things like real time pricing, critical peak pricing, perhaps testing one or both of those in different circumstances for different types of customers. I'm very much interested in learning about how customers respond to those kinds of approaches and how we can use that as a possible spring board to more of a full-scale type of program. Of course, the verdict is out until we see what kind of results we get from those pilots.

There are other possibilities, such as the fact that we are a region where the old legacy programs have kind of fallen by the wayside, as Chuck Goldman explained this morning. But some of that equipment is still in place and those customer contacts. There could potentials to reinvigorate those programs and perhaps reinvent them. These are all the kinds of things that might be possible, but we still have a lot of work to do toward exploring what the potential is.

One thing I see happening is, of course, all the states will have to have a proceeding to look at the new PURPA standards under EPAct. That may be a forum. I would expect that would be a case in the District, at least, to look into what possibilities are that are out there, especially to the extent we can leverage resources we already have.

MR. KATHAN: Thank you.

Any other questions for PJM?

MR. GOLDENBERG: I was wondering how is it you have such a large footprint and you integrate your programs with those of the states and state retail tariffs.

MR. BLADEN: That's an interesting questions, as was alluded to earlier today. There's been some bit of controversy about whether assess to PJM's demand respond products is, in fact, universal across PJM or is somewhat more limited. This is actually right for this Commission and the state commissions to try and come to some agreement on. I think it would be useful to have clarity on that questions. While, in fact, the complaint that was filed here was, in fact, resolved, it's not clear, in fact, what the ultimate opportunities are going to be in some parts of PJM. While most parts of PJM, in fact, have direct access to these PJM markets, there are parts that do not. As long as it's understood, in fact, what the rules are in those areas, I think that's fine. But I think clarity is called for.

MR. KATHAN: Okay.

MS. WHITE: As a follow-on to this question, I think --it's sounds like in some areas where all the stakeholders are working together it sounds like it's something that MADRI is already doing. Could a taskforce be set up to talk to each other?

MR. BLADEN: The MADRI organization is really focused on the Mid-Atlantic where, in fact, there's pretty much general consensus, if not very much consensus that everyone ought to have access to the PJM demand response products. It's the expanded territories of PJM where there's some question about who ought to have access directly to the market through PJM's products. I think there might be an opportunity to have some further discussion. But, at this point, there's none planned that I'm aware of.

I think whatever discussion occurs has to involve the state commissions. I know that there are certain parameters by which commissions can approve participation.

But I think having advanced resolution of those questions would obviously help things along.

(Pause.)

MR. KATHAN: Thank you.

I wanted to focus on New York and I was curious to hear a little bit more about the various measures that were included in the Con Ed rate case in terms of removing the disincentives.

As we've heard earlier, it is a key issue. It's so recent and not well publicized -- a rate case yet. I'd like to know a little bit more about that.

MR. MILLER: We have, you know, a rider on our tariff similar to, I guess, a fuel adjustment rider where we recover extra charges on a per kilowatt hour basis. We were given the right, under that rider, to recover lost revenues associated specifically with the demand response programs that were going to be implemented pursuant to the rate plan. So the issues going forward are simply, really calculation and measurement issues with respect to the programs that will be implement. But the distinction between that and what is referred to a "revenue decoupling" mechanism, which is really more of a general rate stabilization mechanism in which you compare overall revenues to what they were forecast and then have things match up at the end is, I think, much different from mechanisms that are just associated with specific programs and providing lost revenue recovery.

You know, if the question as to programs is just the nice sort of programs and the Con Edison T&D infrastructure programs, which can have a lot of subprograms underneath them --

MR. KATHAN: Is this similar to the old ERAM?

MR. MILLER: No. It's entirely different from the ERAM. The ERAM was a general revenue decoupling mechanism that ensured that the company would receive its revenue -- what the forecasted revenues were even if the sales deviated from the sales forecast.

We had an ERAM in effect, I think, from like '92 to 97. It cost our customers approximately $70 million. Most of which was believed to be at the time having nothing to do with energy efficiency or demand response, but due entirely to weather-related and economic-related reasons. I think in one of the issues that has been raised with respect to revenue decoupling mechanisms is whether they are fair to customers and we certainly -- our experience was that it wasn't fair to customers, even though the company benefitted.

MR. KATHAN: The difference it sounds like -- is it monitoring and verification? What's new in this lost revenue?

MR. MILLER: What's new is in this lost revenue is that we don't look at the end each year as to how our sales may have -- our projected sales may have matched up with our forecasted sales and then have a revenue adjustment as a result. Instead, I think probably the best way to think about this is as a top down versus a bottom up measure. Instead of looking at things from the top down of did sales match up with what they expected and then let's equalize everything, instead let's do this bottom up. Let's look at each individual demand response program, look at what we think it produced in terms of lost revenues, then provide the company compensation for the lost revenues associated with those specific programs. And what it does is eliminates the risks associated with the top down mechanism that you may be providing a revenue adjustment for something that's totally unrelated to energy efficiency or demand response.

MR. KATHAN: David, I wanted to focus in on the similar types of questions I asked Jeff about the regional planning and also -- let's start with that. We'll get to the payment issue next.

MR. LAWRENCE: Sure. The regional planning -- again, keep in mind we're talking about two separate processes at this point. One is the process that calculates the installed reserved margin requirements on an annual basis and that's where we do model, using multi-area reliability studies. We model specifically both EDRP and SCR resources. We have the capability of actually letting the program handle them and it actually then determines the frequency with which those events would happen, given the overall modeling that's done, which, again, is a fairly large, involved stakeholder process. That is how we would then determine what the overall capacity requirements are on an annual basis.

Looking at the planning process, per say, this comprehensive reliability planning process we have, the intent there is to do a forward-looking assessment of reliability needs. And, if a reliability issue is identified, first of all, the regulated entities are asked to provide backstop solutions. What we call "backstop" solutions, which are, essentially, if you cannot get anything else, this is what the regulated entities will do in order to ensure reliability. But, then the emphasis is really on obtaining market solutions. In that aspect, we're looking at generation transmission and demand response to fill the bill.

I think, because this is a new process, we really don't have a lot of experience with it. I know one of the areas we want to gain some more experience on is how we better can track the overall performance as these resources go forward. For instance, if a demand response project is contemplated to be in place three years from now, what are the milestones, what are the performance measures that we use to basically track progress in developing these just as we would with a transmission project or a generation project?

MR. KATHAN: To make sure I understand, you're saying that there will be areas of backstop.

MR. LAWRENCE: Yes.

MR. KATHAN: When does that trigger? The upstate/downstate congestion is endemic. It's been there a long time. Is that a trigger or is it something worse than that?

MR: LAWRENCE: No. Again, we aren't looking at congestion relief as necessarily being a reliability issue. With the bountiful joys of having a full market, you provide economic signals with congestion that indicate it's time to build resources where prices are high. The issues with reliability are, can we meet the reliability criteria that are set up, both nationally and locally within the state? Those are the issues that would trigger the need for demand response or any of the other solutions.

MR. KATHAN: Moving on to the payment issue.

MR: LAWRENCE: Payments you say. Yes.

MR. KATHAN: What is the status of the payment issue? I understand there is an issue in New York. I could be wrong on that.

MR: LAWRENCE: I'm curious. You mentioned that you thought it might be related to the economic programs. To my knowledge, generally, people are not shy about bringing to us issues involving payment, so I'm a little surprised that I haven't heard about it. But, generally, we don't interact with the end use customers -- the ones actually doing the curtailment. We act with their representative. That would be an LSC or a curtailment aggregator. It's conceivable that one of those entities hasn't passed along the payment that might be associated with that end use customer's reduction. That's possible.

On the emergency programs, the reliability-based programs, we have, as part of the overall market settlement process, a 1-month, 4-month and 12-month settlement invoices that go out. Currently, with the metering and the analysis requirements, all of the settlements for the reliability programs are put in four-month true up invoice, which, in this case would have occurred in December for the July event that happened.

Certainly, it's noble goal to look toward getting the metering and communication in place to allow us to do the settlements in the first month's true up. I think that's certainly something to shoot for, but it involves more than just metering and communications. It involves doing the actual processing and validation and preparing the invoices. So, certainly, it's something to shoot for. But, currently, we see that as a four-month process.

MR. KATHAN: I'm possibly not 100 percent clear on this. The state policy has been to move towards more time-based rates, and I know upstate in the Niagara Mohawk and National Grid service territory they've had that for a while. In Con Ed's service territory, are you moving in that direction and response?

MR. MILLER: Yes, we are. Con Edison has time-of-use rates -- mandatory time-of-use rates for customers with demands of 1500KW and above. They've been under that regime for a while. This is not hourly pricing. It's based upon peak seasons and peak periods of the day. The PSC has instituted a proceeding to implement mandatory hourly pricing for that customer group -- the ones with demands of 1500 KW and above.

We have filed draft tariff leaves to implement that. But, as I discussed earlier, I will note that this would apply to our full service customers only. And, in particular, it's our largest full service customers who have moved to competitive suppliers, so they don't form a substantial part of this service territory peak.

MR. KATHAN: Okay. Moving on in the time we have left, let's talk about New England, and particular --

MS. WHITE: Before they turn cranky.

(Laughter.)

MR. KATHAN: I want to ask the same question about the regional planning. I know, Henry, that you mentioned you have -- it sounded like a similar type of exercise to New York and I just want a little more detail about how that planning actually does work.

MR. YOSHIMURA: I think, just to clarify how we do things, first, when accounting for a demand resource into a regional plan, one has to first consider where do you reflect it? Where do integrate that resource into the plan? Because we think about some of these demand resources as a resource, meaning that it's doing something which is affecting demand in certain time period, i.e., let's say the peak. Then it looks a lot like a generation resource, so it looks like supply. So maybe you should integrate it into the resource plan as a supply resource. That may be one way of doing it.

However, the value of that resource is produced by reducing demand. It could also be accounted for in the demand side of the equation. The question becomes where do you want to do it? Does it make a difference? And we think it does. Some resources, particularly, reliability-based resources, capacity resources -- they are called upon by the

ISO to respond in certain conditions. They're not called every day. They're called seldom. They're not producing demand over a lot of hours. However, they're improving reliability of the system because they can be relied upon by the system to respond. So, in that particular instance, reliability-based demand response, we think, ought be accounted for in the planning process.

You have to model it. You have to model how it behaves along with the other supply resources to affect the reliability of the system. Basically, how does it affect the loss of load probability on the system? Once you know that effect, then you can figure out what sort of resources you need to maintain long-term resource adequacy. So, for a resource that's dispatchable in that manner, we think it has to be integrated into the plan as a supply and modeled that way.

However, other type of demand response are not controlled in that way. Price response to demand. Both the program that we run, the ISO runs, the real time demand response program we were talking about before, the Day Ahead program or any price responsive load that's out there that we're not even aware of that gets reflected as a reduction in demand and shows up in the load forecast. So its value is there. It shows up on the demand side of the equation. That's where we think it ought to be taken into account. So that's how we draw the line. Those resources that we know exists that we have control over that we can model. And they do, in fact, improve system reliability. We feel should be accounted for, modeled as a generator.

The other price responsive demand ought to be accounted for in the system plan as a reduction in demand, just as energy efficiency should be accounted for as a reduction in demand.

MR. KATHAN: So the resources that Connecticut is developing in response to the Energy Independence Act, the DG and the various incentivized resource, are they going to be incorporated then into the next transmission plan? What are the steps in order to ensure they're reflected? What is the need within Connecticut and within New England?

MR. YOSHIMURA: They'll be incorporated either in the way I previously described. If they're participating in the market as capacity resource, let's say, then it's a DG resource participating in our real time demand response program. They will be taken into account on the supply side. Other forms of demand response -- economic demand response, time-of-use rates, any impact on demand that's not under our direct control but is going to be affecting demand going forward, we could figure out how to measure that -- figure out the impact of that. It will be reflected on the demand forecast, the load forecast.

MR. KATHAN: Commissioner George, I wanted to ask a couple of questions.

You mentioned that the Act -- may I need more information on TOU rates and is voluntary for small customers and mandatory for large. Could you speak a little bit about that?

MS. GEORGE: Sure. As I said, the time-of-use rates are required for customers -- large customers, 350 KW or larger. And there is a mechanism for us to determine a way for them to opt out of that. Time-of-use rates are optional for the smaller customers, but that's what the legislation requires. We have two open proceedings looking at time-of-use rates. So we might look at how to maybe use time-of-use rates and make them mandatory for others -- large residential customers. That's sort of the base amount that's required by the legislation, but we do have open proceedings looking at further requirements.

MR. KATHAN: Are you looking at critical peak pricing as part of that? I know that wasn't listed in the Act.

MS. GEORGE: It's not required in the Act, but critical peak pricing, dynamic pricing, as Henry said, are things that Connecticut has been discussing. We're scheduled to go off of transitional standard offer at the end of 2006. So it is something that we will be looking at in those proceedings.

MR. KATHAN: One last question for you, which is, I just read that Connecticut has made a decision similar to what I'm hearing happened in New York, not to go to rate decoupling. I know it's an issue that has been discussed inside MADRI. I'm just curious. What is the feeling in each of the regions? It seemed like there was a disinterest, at least in New England and New York on rate decoupling. I'd like to have a conversation among all three regions on what are the benefits and the disincentives?

MS. GEORGE: I guess, from our perspective, we looked at decoupling. There was a range of decoupling mechanisms we had for our electrical distribution companies. We'd had some experience with some conservation adjustment mechanisms. I wasn't there at the time, but according to staff they were administratively difficult and didn't necessarily produce the benefits that we were looking for.

On the electric utility side, we found that providing proper incentives for the utility is the best way to achieve increased use of demand response or conservation measures and energy efficiency instead of going through the more extensive decoupling mechanisms.

MR. KATHAN: Yes?

MR. MORGAN: If I could comment about what MADRI is doing. We're looking at a model rates stability mechanism, which is actually based on a mechanism that's been in place with Baltimore Gas and Electric's gas services for, I believe, about 20 years. It was recently expanded to the Washington gas company as well in Maryland. We're looking at the possibility of adapting that to electric companies in the five MADRI states. Naturally, it's just a model that would then be made available to the commissions if they choose to adopt it.

The idea is to come up with a mechanism that can help to mitigate the extent to which the current rate-making process serves as a barrier that might discourage utilities from actually aggressively pursuing both demand response and energy efficiency generally.

At this point, it's just a model there some states may find useful in some form, but no state has made any commitment to it, other than the extent to which it's already been implemented in Maryland for a couple of gas companies.

MR. KATHAN: Okay.

MR. ROUGHAN: Dave, can I give you some insight in terms of some of our DSM programs in Massachusetts and Rhode Island. We're allowed to earn an incentive for how efficient we are to deliver the dollars per kilowatt, so to speak. That's been in place for many, many years. Naturally, every year the different folks who regulate us all tweak it a little bit and we've got to work a little harder every year. But, again, that's incentive that you get just from doing something very efficiently and it doesn't cover our revenue loss, per say, but it does goes some ways toward covering it.

In addition, our implementation of the ISO New England demand response forms in Massachusetts. We're also allowed to keep a percentage of those payments for our marketing and admin costs.

MR. KATHAN: Similar to New York, right?

MR: LAWRENCE: Yes.

MR. KATHAN: So that provides you an incentive to participate?

MR. ROUGHAN: It covers our costs. And, depending on how extensive we want to get -- we'd have to have additional discussions in terms of probably more incentives in terms of really going above and beyond what we've been doing today.

MR. MILLER: Remember at Con Edison we get an actual dollar incentive for increasing the enrollment in the program separate and apart from what may be any administrative costs.

MR. ROUGHAN: I like that idea.

(Laughter.)

MR. YOSHIMURA: If I may, the issue of the distribution companies earning incentives for participating in demand response programs administered by the ISO was an issue that was discussed extensively in the NEDRI process several years back. The issue there, which is an important one to keep in mind is, that we have, as New York and other places have, competitive demand response providers in addition to utilities who provide services to customers to bring load response to the market. If the utilities are passing all of the savings, dollar-for-dollar, from the ISO incentives to the customer, that makes it difficult for a competitive supplier to compete with that. It could have a market-distorting effect. That was one of the issues that we discussed extensively in the NEDRI process and the NEDRI process recommended that utility companies actually retain part of the incentive payment that is derived from participation in ISO programs, partially as a contribution to costs. But, partially, to ensure that the competitive market doesn't get pushed out.

MR. KATHAN: Jeff?

MR. BLADEN: I guess I wanted to add, given that PJM has participated in the MADRI process, I think part of what Henry just alluded to is actually one of the reasons MADRI has looked towards the decoupling mechanism rather than some kind of reimbursement tool or incentive structure as the means to properly keep the distribution companies that want to participate in demand response whole. It's mostly to try and create as even a playing field. Because PJM has similar structure with curtailment service providers operating in the footprint to extent that one set of market participants was getting a revenue stream from the state regulator via state regulation that others were not. That might somehow distort the marketplace or the value of the commodity.

From PJM's perspective, we really want to see the most transparent price and value proposition possible transmitted to customers such that we get the right economic results. Not to say that regulators cant's come up with the right formula, but as was alluded to, sometimes those formulas change over time and it doesn't always track with the real value in the market.

MR: LAWRENCE: I would just add to that. In our experience what we've seen to date with those payments that go out to LSCs versus aggregators, as we note, we've got almost half the megawatts in our programs that are registered with aggregators. I certainly wouldn't underestimate their capability to come up with very creative business propositions for customers. That's really been the evidence that we've seen. That regardless of what you do with the regulated entities that the aggregators will develop programs that will be just as competitive.

MR. MILLER: I will note that the PSC did handle that with our retail tariff. We are barred from passing through the entire benefit to the customer. We have to cover our admin costs in order to create a level playing field for the competitive providers and they have been very active in our service territory.

MR. KATHAN: That's interesting.

Looking at the time, unless anyone has anything they want to add -- Jeff?

MR. BLADEN: I just wanted to try and clarify one thing about the transmission planning process. We talked about it a little earlier and I know Henry, from New England, referenced how their process does, at least, include the economic demand response. In fact, PJM's process does implicitly include economic demand response. It is built into the load forecasts implicitly because those forecasts are derived from actual performance of the marketplace. So I don't want to leave you all with the belief that, in fact, it's not part of the planning process. But it's not an explicit part of the process. It's implied.

MR. KATHAN: It's been too long a day for me to be able to fully summarize everything that was learned. You'll find that in August.

(Laughter.)

MR. KATHAN: But I did want to thank everyone who has participated. This has been very valuable. And, in addition, I wanted to state that we are still interested in receiving comments.

Aileen? Okay. We are interested in receiving comments. And, if you want a response to what was stated today, any supplemental comments, please enter them into the docket and we'll put out a supplemental notice indicating when the due date for those comments is. It will likely be 30 days from now.

Is that fine?

(No response.)

MR. KATHAN: So, with that, again, thank you everyone for your participation. Have a good flight home and a good night.

(Whereupon, at 5:10 p.m., the above-entitled matter was concluded.)