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RAPPORTEUR'S SUMMARY *

Session One.
Demand Side Response: What Price Efficiency?

There is a broad consensus that providing meaningful mechanisms to incorporate demand bidding into the electricity market is both socially and economically desirable. The consensus, however, begins to break down when the question is further refined to ask about the appropriate way to address price and participation. Bidding a demand curve seems straightforward. Offering demand response as negative demand seems more complicated. How much incentive is necessary for end users to bid their demand curtailment into the market place? Indeed, how much value should we put on obtaining demand response? Is it worth more than supply options being bid? If we consider externalities in the pricing, how should we apply them? If suppliers are compensated at the market clearing prices, is there a reason to compensate demand side bidders differently? Do the compensation issues for demand side providers in capacity markets differ from how the issues play out in the context of energy markets? Are the positive externalities identical in each market, and if not, how do they differ?

Speaker 1. I stand before you contrite, humbled, and apologetic because I earnestly worked to develop and defend load as a resource. I will talk about how and why this happened in the past and why it was a mess. I should've known better because I've been around too long and been involved in too much. After I discuss this issue I'll return to the issue in front of FERC now, and discuss my more nuanced views that I have now.

The original idea of load as a resource was something noble and grand, about making markets work better. The various folks who were involved with this – including myself – knew at the time that they were messing around with economics in a bad way. They used the favorite cop-out: market transformation. The idea was that a market can't work right now so we're going to intervene and mess around with it to help it get to the point where it's going to work.

The end result is that all that help has not helped the market at all, but left us right where we started from. Let's look at why that happened. The justifications included economic dogma,

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welfare analysis, and other approaches. The various cheerleaders were ultimately guilty of irrational exuberance, or some sort of new paternalistic liberalism.

One can rationally differentiate between energy efficiency and demand response. Let's look at demand response. Customer choice and control should be done by utilities, or Load-Serving Entities by cooperatives, with dynamic pricing and fully hedged pricing. There's nothing wrong with a fully hedged price as long as the hedge that the customer pays is based on dynamic pricing.

All that should happen on the consumer side. The wholesale market should create incentives for generation, the right signals for capacity investment, and the optimal dispatch. Unfortunately what happened is that FERC and others pushed ISOs into a focus where even customers got pushed onto the resource side. Instead of trying to fix the problem at the retail, get people exposed to prices, give them devices so they can respond accordingly, parts of the industry went to the other side. In the last ten years the real focus was to make customers day traders in a wholesale market. I should've known better, I'm trained as an economist.

The New York ISO in 2000 argued that customers should bid in the day-ahead market. The idea was that market efficiency would make the market work better.

Now, TOU [time of use] works, it always has worked, it's just that nobody wants to try it. There's long term TOU programs around the country that don't get dramatic results. On the peak days there isn't much of a change more than an off-peak day.

But systematically, it works for residential, commercial, and industrial sectors. Real time pricing works. The Niagara Mohawk model, which Georgia Power and others use, the customer bid in their typical load everyday and settle variations at the real time price.

How can this be any better? One has to buy a position to market or trade it. That model solves many problems but it never caught on anywhere except Georgia. There are 6,000 customers in Georgia, and almost 5,000 megawatts in load is influenced by real time pricing. They've been doing it for 20 twenty years in residential programs. It does work.

However, most of the industry gave up on all of that. There's other things, like hedging instruments that can make this work. A variety of studies demonstrate different kinds of price elasticity. Some Niagara Mohawk customers [now National Grid, in NY] have had 15 fifteen years of experience in real time pricing.

Price elasticities aren't spectacularly high in places where there is real time pricing but they aren't bad. They are distributed as you might expect, a measure of how much the load would change in response to a price. Load responds to price in all cases but much more in certain situations than in others.

Two other RTP [real time pricing] programs are Public Service of Oklahoma and BC Hydro. BC has a flexible TOU where the customer picks the number of peak hours, and the peak to off-peak ratio from a set of alternatives. It allows them to dial in the kind of behavior they can realistically provide. This program's worked very well, but got frozen in time and space because neither pushed them forward, even though they were popular with customers.

There are also lots of examples of direct load control. I'm not a rationing guy, price should do the job. However, vertical utilities have done that for years very well. There's no reason load serving entities or ESCOs [efficiency service company] couldn't run the same kinds of programs. However, one can't make these programs work when there's an ISO program that pays more. I'll get back to that in a minute.

In California during temporary programs, a customer gets 20% off if they reduce load by 20%. That worked for a short period of time. Another idea we'll hear about is priority service.

So how did the industry get caught in this trap? Why did they just keep pushing on, changing retail prices? Why didn't they run demonstrations and pilots, maybe get big DOE stimulus money in the nineties? The real reason is there is a lot of anxiety about prices. Neither regulators and utilities wanted another California to descend on New York in terms of the high prices the industry saw during the 1999 crisis. FERC was eager to help and started nudging utilities to get them involved. It was a lot of forces and pressures.

The other thing is that prices get a little scary. If we look at a price typography from PJM in 1999, it ranges from $20-25 to $70-80 in January. In July there are examples of $800-900 per megawatt hour prices. These prices repeat week after week, the same hours of the day. Then a long dead period, and then boom, they come up again. This price volatility really scares people because it seems like it comes out of nowhere, it happens at the same time of day, but you can't figure out where it's coming from. It seemed like that needed to be quelled and stopped. The problem is that economists argue that price volatility is the essential element for a market to work but then we spend all our time trying to get rid of price volatility. We've seen similar kinds of volatility in other places, including New York and the response is always that we have to fix it.

If one examines load data, loads have this nice bend right in the middle. If I were to lay the load on top of the prices it looks like the highest load over the highest prices. The answer is not more generation, not better marginal pricing, not fixed by the capacity market, but let's have customers act as generators and solve the problem.

This is an alluring and compelling approach, there's nothing like the smell of welfare gains in the morning if you're an economist. Consumers are paying a uniform price. Hourly prices vary. It is a welfare maximization problem, let's fix it. The graphs show it over and over again. It's supply and demand, if the LMP is high and the tariff price is low, the result is deadweight losses.

These are transfers, these deadweight losses. It means people don't see the right price, and they're using more than they should. Therefore we're squandering resources. Coal, the core of a nuclear reactor, natural gas, etc. It's being spent in a way that's not optimal for society. This is well documented by economists.

The argument at FERC is whether customers bidding on a load in the energy markets be paid LMP, should they be paid LMP minus a retail rate something else? The real argument is here. This analysis, which is in every textbook, presumes that the price changes and response received by customers is their reaction to their best self interest.

That's not what happens when customers are paid. There's additional costs because the ISO is paying them as a resource. The math and the economic analysis demonstrate that negative welfare results from setting it up this way. It really only works when prices are really high. When the supply curve is steep and you're way out in the steep part of the supply curve you're almost always assured of having the welfare triangle exceed the payments to customers being paid LMP. That is why there's now a $75 floor in New York and PJM, and I think New England has something equivalent.

But if one examines the studies the floor should probably be closer to $150. The only way to prevent long-term welfare losses is to raise that price. But at 150, most customers are not going to play. It's a stalemate. There's an optimal way to do it, only allow customers in when they will contribute to positive net welfare. The customer then says, "I won't make any money." Either way there is no positive net welfare gain.

So what's wrong with consumers acting as day traders? There are four concerns. First, moral hazard, the kinds of people who have loads, and are going to be able to bid and not do anything and get paid. You've got adverse selection. Some players will bid on days when they know the plant was going to be down anyway. In fact there's no real effect. All these are negative welfare additions. Third, opportunistic bidding, another form of moral hazard, being very clever about how to do that. Some problems have emerged in New England and elsewhere that revealed some problems with using the CBL [customer based load]. All these problems require proving that someone would have done something else in a non-nefarious situation, establishing a counter-factual. There's no real way to establish the counter-factually, universally improperly for each and every occasion. This problem doesn't go away.

Instead we just need to give consumers a price that they can respond to. There are none of these problems, and no counter-factuals to prove in the case of bad behavior, and the market works very efficiently. Each customer decides, I don't want to do this or I do want to do it, and I pay it. It's that simple.

The last problem is attractive nuisance. It's almost impossible to run a good pricing program when the ISO is dominating and allowing you to bid a day ahead in real time and paying LMP but also allowing you to bid in a capacity market to get capacity market prices. How does one make any money? Essentially, the market value is transparent so there's very little an ESCO or utility can do.

There's no more money just because you offered at retail. You have costs, you have to offer customers something less than the market. And it's a lot harder to get people to go on a real time pricing program where they pay the streaming prices, when in fact for free they get a free opportunity to bid when they want to without ever taking a market position. They're free to sign up for a flat price and decide each day, under each circumstances, do I want to use, or bid or buy through.

We're now lost in a morass where we think that load is a resource. Let me be clear, load is not a resource. There isn't any parallel where people take a position in the market without having a counter-position of some form. Wholesale markets are meant to do one thing and retail are meant to do another.

Over the years we've been hearing about demand response and integrating into ISOs. The correct skeptical response to this is, what's wrong with just giving people the prices and letting them do what they want to?

We need to fix the problem at retail. We need to have customers realizing how much better off they can be when they take things into their own hands. This is all customers, not just a few who happen to have the ability to bid in the ISO markets.

Question: Are baselines always useless and not to be trusted?

Speaker 1: There's nothing wrong with a baseline between two parties who decide they want to settle that way. What I don't like is a baseline in a wholesale market. If two parties agree upon it, that's fine, with whatever counter-factual they want to establish.

Question: That's not what I'm talking about, I mean a baseline established as parts of a demand-response program.

Speaker 1: Well I don't like them used in wholesale markets. Individual parties at retail who choose to do a transaction based on the counter-factual should be free to do that.

Moderator: I expect we will hear from demand side providers in the question and answer.

Speaker 2.

I'll provide a brief historical background, talk about alternative approaches, and use some economic theory as a way to provide insights. The difficulty is not really in new ideas, it's escaping the old ones.

It has been over three decades since the PURPA [Public Utility Regulatory Policies Act] was passed, with many ups and downs. The market restructuring has been focusing on introducing competition on the supply-side. The establishment of the ISO markets, PJM, New England, New York, and California represents progress. There are also downsides, like California's electricity crisis.

One result is a hybrid market structure. On one hand the wholesale electricity markets the prices reflect the marginal cost. On the other hand the retail market is under the old regulatory compact. The price is fixed uniform and the quality is undifferentiated. There is an unlimited quantity option. One can consume any amount that you want by as much as you want. That is requirement service.

The overall system is based on a single settlement, after the fact, based on the meter of the load. One lesson from the California electricity crisis is the importance of demand response. Many experts have noted that competitive electricity markets cannot be sustained if consumers are insulated from market prices. Progress has been made since the Energy Policy Act of 2005. FERC has done a great deal in reviewing this area and most recently the NOPR [Notice of Proposed Rulemaking] has gotten all the attention around this topic.

Let's start from the very basics to understand better what really is a demand response product. The FERC definition is clear. Demand response means a reduction in the consumption of electricity. A demand response resource represents customers' ability to reduce electricity consumption.

Thus demand response is really a derivative product. It's complicated. It's a composite option. There are several elements here. Baseline, as discussed with the previous speaker, is not trivial at all. The baseline is a quantity threshold in this option. It is established only when the unlimited quantity option is exercised. In the basic electricity service, you can buy as much as you want. In demand response it's real to give up that right.

The first thing is a threshold. The consumer will only get paid if they consume less than baseline, however the baseline is established. But in the basic service you have that option. You have to give up that option by exercising it. Baseline is a way to do it. The price threshold in many of these proposed designs includes a threshold above which the demand response option can be exercised. So, demand response is allowed to offer into the wholesale electricity market when it's appropriate to set prices.

Finally, there are compensation rules for how much demand reduction one will get paid. For example, under the condition that your consumption is less than baseline, when the wholesale real time price at LMP is greater than the threshold, or the wholesale price is greater than offered. These are very typical in the derivative or composite option structure.

There are two options that I want to highlight. One is the unlimited quantity option. The second is to exercise the demand reduction option. So there are two stages in terms of settlement. One is about demand response as a capability. Demand response as a capability has many benefits, including some public benefits, like mitigating market power. It's the existence of that capability that is designed to produce an elastic demand curve. That can mitigate market power. Demand reduction without elasticity is nothing but conservation. Further, the demand reduction is really a realization after the option is exercised. Before the option is exercised there is a value, and after the option is exercised there is a compensation rule associated with that.

The demand response resource has at least two dimensions. One is akin to a capacity product. The other one is an energy product. So first, demand response is allowed to be paid in the capacity market, which I view as appropriate. The capacity market is in large part created by the missing money because of a lack of demand response. The demand response capability can get a revenue stream through the capacity market.

In the energy market, the energy component is truly a private product. The single price roof of a competitive market argues that all these perfect substitutes should receive the same price. If demand reduction and releases the energy, it's about comparable treatment of demand supply.

The complexity here is whether this demand option has been exercised. One element in this is the baseline. The presumption is that the unlimited quality option has been properly exercised. In many cases it has not. In this kind of situation, we may be trading an option in an energy market. So there are oranges and apples being traded. That becomes complicated. There are various rules that need to be put in place to make sure that the single-price rule still prevails.

One can group the proposals for dealing with demand response into three categories; the traditional approach, the "second best" pricing approach, and the "first best." The "first best" pricing approach has three subcategories that are not mutually exclusive. They share similar ideas, with some fine differences.

The only approach that is unique in what is paid is the "second best" pricing approach. There, the payment is a wholesale market price, less the retail rate. The others all use wholesale market price. This is the proposal that was been considered by PJM and ISO New England before the FERC NOPR was issued. The others all pay straight wholesale price.

The main difference lies in the contract for baseline, where the baseline is properly exercised. In the case of traditional approach, there's no contract. I will clarify that later. With "first best," there is a contract there, whether explicit or implicit, to ensure that the unlimited quantity option is exercised and that baseline is established. The "second best" approach can be viewed as a compromise option.

That option is within the FERC's jurisdiction without an ISO getting into retail. However it is still controversial. There is a sense that the demand response is traded as an option, and that the pricing rule is trying to adjust for this netting out. Using the retail rate is really an attempt to convert that option into something more comparable to an energy product.

OK, let's focus on the traditional approach and look at some of the issues. It is an unbundled contract in the use of a two settlement system. The traditional approach does not require that demand response providers show that they own what they are selling. The customer offers demand response to a demand response provider and the provider offers that into the ISO market, where it gets cleared and paid at LMP.

In earlier pilot programs this is the way it works. The demand response is determined by the difference between the actual consumption and the baseline. The baseline is administratively determined. There is no discussion about ownership of that amount. One cannot identify the owner of the energy.

The traditional transaction is based on metered load, and it's balanced clearly. The demand response transactions create a deficit for the ISO; there is missing money that needs to be recovered, so the cost allocation is needed. Also, the number of megawatts is not balanced so their load reconstitution is necessary. These elements are a part of life in a traditional program.

The problem here is the missing property rights. We cannot identify who owns what has been sold. A property right is the cornerstone of a functional market. Market competition depends on voluntary exchange of privately owned goods or services. The missing property rights can present problems.

The traditional approach is really inherited from the old vertically integrated utility. In a vertically integrated utility, customers are paid a voided cost. In this case it is extended to wholesale market price.

The administrative customer baseline is set using sophisticated statistical methods to forecast customers' consumption level. The ownership and entitlement issue is not really an issue in the vertically integrated utility. It's just a question of the money. There is no market incentive that can create problems. In a market setting the lack of ownership creates several unintended effects. Inefficient price formation is a concern. So is load-shifting behind meters.

Illusory demand response is certainly possible. Even though there are no illegal activities. One example is commonly called the double-payment incentive. The double-payment incentive allows a customer to put a generator behind the meter. The customer can get cheaper electricity than the retail rate when it is much higher than the baseline, offer their demand reduction as a response, and create their own electricity behind the meter. It is risk free profit. Imagine a consumer who has a generator with a marginal cost of $250, so that is his opportunity cost, and the retail rate baseline at the moment is $100. Normally he would not run that backup generator. But when the customer is offered a wholesale price, $160, and in this case the opportunity cost is 150 because you can keep $100, and the 200 minus 100 is 150, and compare that with the LMP 160, this unit will be dispatched. The demand response will be accepted in the wholesale market. This unit will run. The social cost, in terms of resource cost, is $90. This is inefficient. In this example the demand response is treated more favorably than the generator on the other side of the meter.

Another aspect of this is that even if this generator is efficient, let's assume that this generator's marginal cost is $150, and it's efficient to dispatch it in any case. Even though it lowers the opportunity cost of consumers from 150 to 50, no harm is done. Without the demand program the generator would have been dispatched in the wholesale market but now it's actually dispatched in the retail market. There is no impact on LMP at all, they just move it to the other side of the meter. In that case, who pays for demand response? The other customers. There is a cost shifting here. It is not efficient and it is a huge problem.

One shouldn't underestimate the scale of the problem because customers have an unlimited quantity option. That's like a bazooka that can blow up any small hole in a big way. In some situations and some analysis, it is possible for these kinds of economic losses and cost shifts to outweigh the overall benefit of a demand response program. The cure can be worse than the disease.

Further, even if we assume that all customers are staying in the market and honestly trying to respond to prices, we can have problems. For instance, phantom DR can be created without any market manipulation. The following example could happen daily. A manufacturing company owns two identical facilities, so there are two meters. This is a situation in which the load can be shifted behind multiple meters. Both facilities normally would consume the same amount of electricity, 80 megawatt per hour when these facilities are running at 80% of their full capacity. These numbers are established as their reasonable baseline demand numbers.

Assume that these facilities are offered a demand response program. Instead of running both facilities at 80%, the manufacturer will alternate running one facility at 100% and the other at 60% - remember they are able to shift load here. As they shift back and forth between each facility, the *average* load for each still reads as 80 mw, but the company gets credit for 20 mw of demand response each day even though they are still using an average of 160 mw per day. The company's total demand is not reduced, but by shifting load back and forth in their two facilities they create the illusion of 20 mw of DR each day, and get paid for it by the other customers.

What can we do about it? The demand response approach needs to be modified by a demand settlement system to complete the linkage between wholesale and retail markets. A two settlement system establishes the property right. It enables one to offer demand response into the wholesale market. However ISOs need to add a demand subscription service that is required for customers taking part in DR programs. This means that one can retain the benefits of demand response, but we lose the situations that I've described where some customers pay illusionary demand response.

With demand subscription the customer buys electricity ex-ante. That is established as a baseline in a demand subscription "standard service." In real time they can settle any refund or extra consumption through a default rate that can be linked to wholesale electricity market prices. So there is an unbundling of basic service into standard service, for subscription, and the default service to handle the differences. Once that is done then the rest is fairly straightforward. The demand response program allows customers to sell any unused amount in the wholesale market if that provides a better deal. It continues to provide access to any amount above the baseline at market rates.

This offers a two sided customer baseline, which was not in the current design. The property right or ownership, the entitlement, is unambiguous. That solves the dilemma that I mentioned earlier.

Critically, this is a win-win deal. The kinds of cost-shifting problems, consumer losses, and inefficiencies that I've described all go away. Further, modeling shows that the consumer surplus and peak demand response are maximized. Demand subscription basically pays the peak consumers to reduce demand. These benefits are obtained in such a way that there will be no customers left behind. Everyone gains. Customers in program and out of program makes gains, and this occurs both on or off peak. Demand subscription provides a way to introduce dynamic pricing with a default rate. It can overcome one of the key political barriers to dynamic pricing. It undoes the cross-subsidies in such a way that it creates no losers.

Question: Under the demand subscription service, somebody would subscribe for a certain amount of reduction. However they could still buy through at the market rate. So you really don't know how much that customer is actually going to reduce demand.

Speaker 2: Demand subscription is not to subscribe the reduction. It's to subscribe the total amount that you want to consume. For example, if you expect that you want to consume 100 megawatts, the next day, you can subscribe any different amount. And then if you consume 80 megawatts but you'd subscribed 100 megawatts, you can get 20 megawatts as demand reduction sold at your default rate.

Question: If you don't use your 100 megawatts but use eighty, but the market price is even lower than the subscription, does the customer then have to pay extra if they reduced demand but the prices are lower than during the subscription time. Do they actually have to pay for it? The subscription has an embedded price in it, right? Let's say it's $100. What if, in real time, the price is $50 and you only use 80 megawatts?

Speaker 2: When you say $50 you mean the real time price? The real time price will not affect how much you pay. Demand subscription is essentially a forward contract.

Question: And if they use less, do they have to pay for the difference that they don't use?

Speaker 2: No, you don't have to pay the differences for the amount you use. You only pay the amount that you subscribe. The two settlement system here is that when you subscribe you're already committed to the price and a quantity.

Question: You're committed to a price a quantity, but if you don't use the quantity, can it become a liability to you?

Speaker 2: No. The amount that you don't use, 20 megawatts, you can dispose of it any way. You can throw it away, you can sell it, you can get a refund at the default rate that you paid.

Speaker 3:

I'm going to try to approach this issues from a regulatory perspective. Let's start with basic stuff, what is the purpose of regulation? All statutes, federal statutes or the various state statutes, have something in common. They direct the regulatory agency to ensure reliable supply of the service at just and reasonable rates. That's uniform, you'll find that just about everywhere. They define just and reasonable rates in various ways, but arguably it's the lowest possible rate consistent with a reliable supply. This means all the costs of production are covered.

It also means there's a fair return to the producer because absent of fair returns you wouldn't have a reliable supply. So the lowest price consistent with those conditions is in fact a pretty good definition of a just and reasonable rate. And just to put it into an overly simplistic mathematical example, if you can get the exact same product for either $5 or $10, $5 is a just and reasonable rate.

If a commission fails to do things that would produce $5 and a reliable supply and instead customers pay $10, they are paying an excessive price. Five dollars is the just and reasonable price. In terms of the grids operated by the RTOs and the ISOs, our collective need for electricity over vast areas dealing with tens of millions of people should be satisfied at a lower cost than its being satisfied at today.

In other words, the grid can and should be operated more efficiently than it is today. When I use the word 'efficient,' I may be focusing on what you might think of as engineering efficiency. However engineering efficiency and economic efficiencies are very similar concepts. So where does demand response fit into this basic equation?

Demand response will make the grid more efficient. It will allow the grid to provide the same service to customers but at a lower cost. This means a grid in instantaneous, continuous balance. This is important because a change in supply or demand may change prices, but it also affects the overall capability of the market to perform. In electricity if there's no instantaneous balance, there's no market. Physical balance can be maintained by a decrement of load or an increment of supply. When DR clears in the market it displaces a more costly alternative. If it competes head-to-head and clears and get paid, it means a more costly alternative was displaced and was not dispatched. That makes the grid more efficient.

If DR doesn't clear because it's more expensive, it doesn't get paid. When DR does clear, it reduces LMPs and at the same time it enhances reliability. A lower load is generally speaking, more consistent with a reliable grid than a grid pushing the limits of capacity.

The primary reason this issue is controversial is because the dollar values are significant. They indicate the power of demand response to discipline the markets, and on the other hand they indicate how big the stakes are. In August of 2006 PJM hit its all-time peak. Prices also reached their highest point. In that month of August 2006 PJM paid $5 million to demand response providers in the energy market. The reduction in LMPs was $650 million. That's a very dramatic cost benefit ratio, 650 million to 5 million. LMPs were reduced by $645 million in that one month. You may consider that nothing more than a wealth transfer from generators to consumers but it certainly satisfies the purpose of regulation that I described earlier.

Second, the service was reliable. There was no welfare lost there. There may have been a wealth transfer from generators to consumers, but where was no net loss to society. There was a gain by consumers.

DR moves us down the supply curve to a less expensive, less soaked, less sloped portion of the curve. The function of reducing prices occurs almost anywhere where there is a little bit of slope to the curve. The only way this doesn't happen is where the cost covers literally flat. Some PJM studies show that reductions in LMPs by as little as 50 cents a megawatt hour have net gains that exceed the net losses.

That's at a 50 cent per megawatt hour change, as opposed to the $300 megawatt hour change that occurred in August of 2006. Further, the reduction in LMP is not the kind of arbitrary disallowance of cost that some regulators have implemented in the past. This is a market mechanism with a competitive outcome.

It's simply two resources. I do view demand response as a resource because it balances the grid. It's a competition between two resources where a less expensive resource clears and the more expensive one doesn't. So why should we pay for response demand at all, and why should we pay for LMP in particular? I'll offer you a couple reasons. I view demand response as a service provided by some customers to other customers. And generally speaking, in our free market economy services should be compensated for.

The service provided to other customers is that LMPs are reduced, and other customers are the principal beneficiaries. DR customers are selling a service in the market. It's certainly not costless, it's not a matter of walking through the building turning out the lights. It's a fairly complex decision making process the user goes through. They invest in building management systems, communications systems, or storage devices. They may be able to fill in a valley and cut a peak, another example of increasing the efficiency of the grid. If we can cut peaks and fill in valleys, by greater reliance on storage, that's undoubtedly a social good.

A DR customer has to weigh a number of factors. They are measuring preference for comfort versus the price they can get paid. The value of the service that the customer provides has a clearly identifiable wholesale market value, and that is LMP. And as we all know, LMP reflects the marginal cost to society of maintaining the grid in balance. It's either the cost we incur to keep it in balance, or it's the cost we avoid if we keep it in balance by DR. But it is the marginal cost. And when DR clears, the marginal cost that's represented by LMP is what's saved. LMP is consistent with the basic economic principal that welfare is maximized when price equals marginal cost. it is a competitively determined price, it's transparent, it's the right price in the wholesale market.

DR allows a reduction in the price of electricity to make the markets perform better. All the while not interfering with the primary market functions. In essence the world is changed, as the smart grid has developed, load is not the inflexible thing it once was. It's flexible, just like there are flexible supply resources that can ramp up and down.

There are other supply sources that are not flexible. We don't ramp nuclear plants up and down, they run all out and for good reason. They're not flexible. Load can be a flexible resource and it should be treated as such. It is dispatchable, and it can create the necessary balance. And it has a specific market value.

It's discriminatory, in the legal and economic sense, to pay two resources at different prices when they have the same wholesale value. I'd like to dissect for just a minute the customer's situation when they engage in demand response, because there's tremendous attention paid in this debate to the retail arrangement. The customer is engaging in two separate, unbundled transactions when they engage in demand response. One transaction, the buying of retail power, and they're either paying a tariff price or a negotiated price from their retailer, if it's a restructured state.

Then they're engaging in a separate, wholesale second transaction. They're selling a balancing service to the wholesale market at the wholesale clearing price. These are two separate transactions, in two markets, with two different prices. They are not the same.

Why a different price should apply as a practical matter is something else, there's virtually no DR in the energy markets at the moment. There is a fair amount of DR in the capacity market at the moment in PJM and New England. This is because demand response is paid the clearing price in the capacity markets but it's not in the energy markets.

Like any other economic activity if you pay more, one will get more of the product.

It is probably disingenuous to try to apply questions of welfare economics to these issues. There is no empirical evidence that the price of products that one might consume instead of electricity are priced at the welfare maximizing level. There's no reason to believe that the price of electricity is set to the welfare maximizing level. There are too many other factors at work. There are subsidies in the price. There are tax breaks. There are inefficiencies in the input prices that go into making electricity. There are economic grants earned by low-cost producers, which are part of the single clearing price mechanism. There are a myriad of externalities that are not reflected in the price. The idea that price itself is welfare maximizing is probably not true.

Ultimately, demand response is just another competitor, a new entrant. It increases completion and new entry which makes the markets more efficient. It's a market mechanism that can still satisfy everybody's preferences, but at a lower equilibrium.

We should focus on macro analysis of the grid, rather than microanalysis focused on the internal rate of return earned by the customers providing the demand respond service. They may very well earn a decent return, but we don't engage in that analysis on the supply side.

There's a single clearing price for all market entrants. We don't engage in that microanalysis for one class of resources, and we shouldn't on the other side of the market either. It's a double standard. Instead, we should focus on the big gains by bringing the grid down the curve to a more efficient point for the benefit of all of us.

Question: If we assume that compensation in the energy markets for demand response is LMP with no adjustment, should the inducement for a customer to respond in the energy markets be LMP plus it's foregone cost in retail rates?

Speaker 3: No. I don't view cost-saving as compensation. It's an externality to the market, not reflected in the wholesale market. It is not compensation. If you pay LMP the cost of the market is LMP and nothing more.

Speaker 4.

I'm going to talk about this issue from the perspective of consumer and environmental advocates. We've heard fairly extensively about the benefits of price responsive demand. The short-term cost-savings of reducing demand in high-priced situations are fairly well known.

What about long term price benefits? If you know you can avoid a number of price spikes when a long term contract is being negotiated, then obviously the price of that long term contract can come down a little bit as well. Let's take a look at both kinds of benefits.

There are market power mitigation benefits as well. There are also a number of market efficiency gains. If you talk to generation owners about how the energy markets work they'll complain at length about a number of situations that may or may not happen on a small number of hours. However, it's important to remember that the dispatch of generation units to meet load is far from perfect. There are a number of small inefficiencies that have to occur to run a reliable electric system. Demand response in the energy markets can help us improve the efficiency of dispatch.

We also know that the amount of capacity needed in the market can be lower. The amount of transmission and distribution that you have to build to meet that load can also be lower, and there are cost savings there. There are significant reliability benefits to having demand response. It is resource that can respond very quickly.

There is a very good benefit if the ISO or the control room has clear knowledge ahead of time of how much demand response is available to them, and at what times and locations. This is significantly different than just depending on individual consumers to respond and guessing what that response will be.

There are environmental benefits as well. Demand response is only in place a relatively small number of hours over the entire year. So if you're looking to solve carbon dioxide and greenhouse gas emissions, demand response is not going to give a huge benefit. It has other benefits, some long term. For instance, demand response can certainly improve the ability to integrate variable energy resources, such as wind or solar or hydro. We've some some ISO analyses that demonstrate through scenario analysis that the environmental benefits of demand reduction on a peak day are significant.

In terms of this question for consumer advocates, they ask is there enough of it? Some argue there's already plenty of it. However, I'd argue against this. Consider the obligation in New England's forward capacity market that starts in about 2 weeks, June 1st 2010. There are nearly 1,000 megawatts of customers who are reducing demand or have some other behind the meter generation that is not subject to air permits.

The majority of emergency generation is subject to air permits. However, over the past few months, the maximum response on any one hour was 14 megawatts. Given that there is 1,000 mw available, this seems like very minimal use of this resource. That seemed a little strange to me. I thought, maybe that's just January to May and it's not the right season. So I went back and looked at the prior two summers. The numbers are almost identical. There isn't enough yet. We have more evidence that demand is inelastic, and we're not getting the response to price that one would expect. There are times over the last six years where the price shoots way up during short periods and one would expect DR to be implemented at those points.

If we focus in on the top 5% of those hours, the problem gets even worse. It's a relatively small number of hours. The price shoots way up. There are a number of benefits if we can respond to those prices, and yet demand response doesn't seem to be happening at anywhere near the level that one might expect. The idea that demand response is being used extensively in our energy markets is not accurate.

We do need boundary conditions, some common sense conditions in place. We also need to address issues in the broader picture and perhaps adjust the way we're operating. There are some barriers to participation in the energy markets for demand response. I categorize them here as time, capital, knowledge, and tools. End use customers don't have these things and that's what prevents them from responding to high prices. Even if we were to force real time retail rates on consumer, they would not bother to respond. They don't have the time or knowledge to respond. They don't have tools, and they often don't have financial capital to finance tools they need.

From this perspective one should not think of load as a single block, although that is often the underlying economic assumption. One of the key questions is what these issues mean for an individual customer or rate payer. We should have three, or four, or five people knocking on my door offering to help me figure out how to adjust my load during certain hours. Right now I have none. That's residential. A small business would have a least a couple of them knocking on the door. More competition is a good thing both for price and for innovation reasons.

The key question that FERC put out in the recent NOPR is how much we should be paying for DR. There are a number of answers: full LMP, LMP minus a generation rate, LMP minus G plus X. Where X represents some costs to overcome the barriers that I outlined in the last slide. It's really hard to figure out what that X should be, it probably varies widely from one customer or customer group to another. Or should we pay LMP minus G, plus the T and D rate? It's hard to figure out exactly.

The answer for a non-participating customer is that they don't care as long as the load is coming in cheaper, and it's still clean and reliable. They do not care what is paid to demand response. They want a cheaper load over the long term, over five years or ten years.

One shouldn't fall into the trap of wanting the price of electricity supply to go down to zero or some really low number. This is because, over the long term all the generators go out of business and then the system is broken. We need a sustainable system that can serve load over the long term, reliably, cheaply, and as clean as possible. Arguably this has not been happening in New England.

What are the consequences of paying demand response the full LMP? The answer is that it is OK, the incremental cost to serve load in that hour is LMP, why wouldn't you pay them LMP?

Is it paying them too much? Well, electricity is not a conventional product. One is buying reliable electric service for the house. LMP has proven itself to be really good at economic dispatch. There are a couple of studies that have proven that LMP doesn't do a particularly good job at predicting where new generation will be built, or where existing generation will retire. There are a lot of other factors involved in those issues.

We have heard an argument about infra-marginal rents and the concern for too much price responsive demand in the energy markets. If an ISO were to pay full LMP and allow the demand response providers to provide some response during the high priced hours we would hopefully get quite a bit. However, that behavior would clip the high-priced hours a little bit, which makes it less attractive for them to participate.

The concern for too much, and is the market going to spiral in one direction or another presumes the wrong answer. The situation actually self-corrects itself, which is optimal. If there's not enough, prices will continue to spike. If there's too much, prices won't spike enough and they'll get less of it. And it'll just balance back and forth over the long term.

From a consumer advocate perspective, having a market is not the point. Having the long term lowest-cost that's also clean and reliable for customers is the point. So some would argue to pay them LMP but it doesn't work. There's a mismatch when you pay them LMP. You don't collect enough money. We've heard about two or three different algorithms that can collect the right amount of money in the energy market to get a balanced approach.

Yes, the price that gets paid to suppliers is different than the price paid by load. That's OK. There is a legitimate concern that the cure can outweigh the disease. It's clear there has to be a limit on this. You can't just allow demand response into the market at any hour they want, at any price that they set. Clearing generation, plus a significant amount of demand response, especially in hours where the supply load is flat, makes load pay more per megawatt hour. A stop-gap has to be set somewhere. Once the price gets to the point where it's costing more, you have to stop. Those issues can be calculated in a near real-time basis.

Another argument concerns smart grid. Advanced meters for retail customers would definitely help. We'll have to see if the the reality meets the rhetoric. However, we're not there yet. There is going to be a point where it rolls out to a large number of customers but that is not now. As it starts up we can look to early adopters to see how it works. Nonetheless, it's just not clear at this point how it will work on a large scale.

Once that technology is usable to a wide range of end-use customers, when the demand response provider comes knocking they'll say no thanks, I can do it cheaper on my own. Until that point, demand response providers can provide great service to end use customers. Even when all that technology comes out there's still a small number of people who are going to continue to use demand response providers for one reason or another, it's hard to predict what those are.

We need to stop wasting rate payer money. The way we're doing it now, by just allowing the high price spikes when people would respond given the ability to do so, just wastes rate payer money. The economic theories discussed earlier are very important. I'm certainly not suggesting we ignore them. We allow them to guide us. But we shouldn't allow them to constrain us in designing a market that works for customers. Demand response providers fill an important niche.

Question: I'm curious about your allocation proposal. Are you proposing that in intervals where demand response exists, that load would pay higher than LMP?

Speaker 4: I have to parse your words for a second. The best way for me to answer your question is to say no, but the problem I'm having is with the word LMP. The basic assumption is that set up the system so that you clear the main set of generation to meet the load at the appropriate LMP. OK, that gives you a number, call it $100 per megawatt hour.

Now stick into the supply stack all the demand response that has offered in. However much that is. Run through and figure out, OK, if I clear a bunch of demand response, I actually have fewer megawatt hours of load, so I'm going to call it billing units. I have fewer billing units over which to allocate the total cost of supply. So if I have fewer billing units in the denominator, I might actually make the price above $100, which is sort of my baseline in this case. If that's the case, the demand response doesn't clear.

So it's actually two different prices. One price gets paid to all supply, both generation and demand response. A different price is paid by load, because you actually have to subtract out in the load part of it, the amount of demand response that you've cleared. Because you've got that many fewer billing units over which to spread the cost. You go until there's a tie.

Moderator: If wholesale markets have evolved then there should not be concerns about setting prices for the generators' cost. The market should determine the price. That is how some argue we ought to treat demand-side. Is that a contradiction to the way supply-side options are treated, where we're not supposed to worry about the costs? I've heard this is a specious argument so I'd like to give the first speaker the chance to explain why. [Laughter]

Speaker 1: The only way to measure how markets can be improved is to have some standard for how markets operate. So if you dismiss welfare economics then there is no other argument, or way to explain the market's getting better. So the idea of a welfare platform is not that the current market is an equilibrium, but we can define that equilibrium, and we move towards it. We heard about the issues that come when you have somebody who does not buy a position in the market, and exercises a free option. Actions occur that are not consistent with the best thing for the market.

So this whole business about looking at the customer is that it's a baggage of welfare economics. If you want to approach it another way, then that's good, but you also can't carry around social welfare and efficiency.

Speaker 3: All I'm suggesting is that we value the two resources equally. If you want to engage in a detailed welfare economics analysis do so for the two resources on the same basis. We should make use of the tool. They are almost perfect substitutes for one another.

Speaker 4: I disagree. We should use welfare economics, as I said in my presentation, to guide us. It makes things messy, but I do think that the people overlooking the electricity system on our behalf are smart people. They can decide that welfare economics is a great guide and it can be used in many places but in other situations we have to moderate them a little bit, for the reality on the ground.

Question: Imagine this scenario. I want to buy an old textile warehouse and plug in every $15 hair dryer I can buy at Wal-Mart. I'll run those hair dryers so I can set my customer baseline. Then I'm going to bid in my load to the New England ISO and get paid at the marginal cost for shutting off the hair dryers, which serve absolutely no purpose other than setting my customer baseline. Exactly how does one stop that.

Speaker 3: Determining the right level of compensation does not turn on whether people cheat or not. The right level of compensation is going to be the right level of compensation.

Question: Why is that cheating?

Speaker 3: First, get the level of compensation right, and second, when you find people cheating don't pay them. That's point number one. Second, customer-based load should be based on a sophisticated engineering analysis, not on some historically derived baseline, where customers can ramp it up or down for the sole sake of taking a payment. The consumption in a given building should be based on well-modeled engineering assumptions derived from the building materials, the occupancy in the building on a given day, the temperature set point that's chosen, the ambient temperature outside. In other words it's a mathematical model of what a business' usual consumption is. It can't be gamed.

Question: All right, assume they just use the hair dryers to grow tomatoes then.

Speaker 3: A customer baseline the way I just suggested won't be able to get away with that. It's going to be an engineering analysis of how you run your business.

I'll repeat the first point. The right price is the right price. If somebody's cheating, penalize them, don't pay them. Don't choose an improper price because you're worried about people cheating. It really, two distinct questions.

Speaker 4: Thanks. I agree to some degree. However, if you increase the price you will probably get more people cheating. You do have to worry about it. Especially from the consumer advocate point of view. We don't want to pay people for demand response who inflate their baseline.

Nonetheless, it's a bit of a baby in bathwater argument. We should not throw out all demand response because somebody's going to cheat. People cheat everywhere, and no matter what a small amount will get away with it. We lose that money. The amount of savings is going to so far outweigh that. So we trust the market monitor to look out after that and monitor generator behavior.

Speaker 2: If the ISOs know who owns what, and that people sell what they own, they can police it. If by design the ownership is missing, how do they know what is manipulated?

In my earlier load shifting example it gets fuzzy. It's been suggested that it's not allowed. FERC should clarify whether that example of illusory demand response is a violation of anti-manipulation rules.

The problem for a market monitor is they need to have a way to find out what's going on so that they can implement the rule. Who is legitimate? The answer seems to be that it's legitimate when the benefits outweigh the cost. However, I don't know. Given some of the examples we heard about earlier, it's not clear how much of the cost is really paying for nothing? There are built-in incentives for people to do manipulative things.

I can imagine other legitimate uses of new technologies that may be nefarious. Resources will be misallocated. The calculation may not be legitimate.

Speaker 3: We can satisfy that very legitimate concern. Demand response is reasonably defined as a reduction in demand taken in response to price. So, first you want to prove that what has happened has occurred in response to price. It's not business as usual. So for example, we could have a customer, this building, and have a pre-set operating schedule where they tell us, normally we set the temperature in the building at 72 degrees. If you tell us the price, the LMP has risen to $150, at that price we're willing to sweat a little bit and we'll raise the temperature in the building to 75 degrees.

It seems to me that's not manipulative, we can show you that this is the action they took. They actually took an action, they changed the temperature because at that price they were willing to sweat a little. It seems to me that answers the MNV problem, it answers the CBL. It shows the customer did something, and they did it in response to price. It's an example of the kind of proof I think that most ISOs would say, yeah, this is legitimate.

Speaker 2: Certainly things can be tracked. Rather, given the missing property rights which are a fundamental issue in market design, can we identify all possibilities? A very simple example would be a shopping mall, if you have air conditioning in each shop and you try to shift their load, then no one would actually be able to track it down. This can create demand response when there is no reduction in actual load.

This should not be about identifying a specific situation because they will keep popping up. Rather, it's about certifying that demand response has truly occurred. There are deep concerns for monitoring.

Question: This is a clarifying question for speaker 2. If you have an explicit ex-ante contract between a buyer and a seller, and it's a voluntary agreement between both sides for a quantity, and then the buyer chooses to resell some of that quantity at the LMP, that's an explicit contract correct?

If there is a regulated tariff with a full requirements obligation under a subscription service where you make explicit the amount that they're subscribing for that's clear. However, without a baseline calculation policing, evaluation, or judgment it's open to abuse. So there must be a baseline calculation that is still part of the subscription service against tariff rates where it's a one-sided decision. That's my assumption. It wasn't explicitly stated in your presentation, I just wanted to clarify that.

Speaker 2: That's an excellent question. When the NE-ISO implemented demand subscription, the current system is a single-settlement system with an unlimited amount as an option. That new system is still unbundled and is an ex-ante subscription. You can still subscribe any amount in principle, and ex-post you have a default service which you can get.

Ex-ante you can get your price hedge. However, they have to determine a fixed quantity in advance. After the fact they can still get an unlimited amount at a default rate, which is linked to the wholesale price. The option is still there for the customers but they are unbundled. You are right, there needs to be a limit. The main reason is to allow customers their legacy. They are entitled to a flat, fixed retail rate and for the amount of consumption.

Some calculation, perhaps based on historical consumption, may still be needed to set a bound so that you cannot subscribe to a huge amount in a way that would allow for manipulation. That would set a baseline. The ISO subscription service can actually offer further options.

If an entity really wanted to hedge against the price risks for any amount above their baseline, there could be other opportunities for an option service. Say that, you have the option to lock it into a certain price if you need 50% above your subscribed level. Any subscription service needs to be finite and then the possible manipulation can be avoided by setting a limit.

Question: In circumstances where LMP is negative should demand response be paid for increasing demand, to pay the LMP? If so, I have some follow-up questions.

Speaker 3: I see the logic but I do not suggest it.

Speaker 4: I see the logic, but I'm trying to find the scenario where a demand response provider would actually clear in that scenario. I just don't think it would ever happen.

Question: I'm intrigued by the claim that by paying full LMP to demand response, that all consumers are always better off. PJM was asked to do an analysis by the Maryland Commission solely on customer expenditures under full LMP compensation or LMP minus G compensation, as it's being called in their stakeholder process.

It's not entirely clear that if you allow demand response to be paid in all hours, at full LMP, that all consumers are better off. In fact, it depends on the retail rate structure whether it's fixed price rates or customers facing a dynamic rate, real time LMP. As an example, in the BG&E zone in PJM for the year 2013, assume they had just 1.5% of load as demand response, and all of it was on a dynamic rate that was paid full LMP. Consumers would be worse off over the entire year by $17 million in that zone. This assertion that all consumers must be better off, is not borne out when one does a rigorous analysis. Now, if one wants to make the argument that we want to maximize consumer surplus, then that's something different than paying the market price in all hours. That requires a different mechanism.

Another concern in PJM, is the whole measurement verification issue, trying to measure the customer baseline load. By trying to avoid the moral hazard and the adverse selection problems discussed earlier, they've had to resort to administrative mechanisms to make sure that customers aren't submitting settlements for all 24 hours in the day because the baseline has been computed incorrectly.

When there is demand response at low prices on a consistent basis from the same set of customers at PJM, is that truly demand response? They have to go investigate this. That takes a lot of time and resources from the RTO that is not computed in demand response costs or savings.

Speaker 3: First, yes it is possible that DR can end up costing customers. This only happens when there is a lot of cost to pay for it, and it's at a very flat portion of the curve, meaning there's no LMP benefit. It's conceivable. I suggest that's not a likely scenario, it's rare.

If it worries you, there's a policy to address that concern. I'm supportive of an algorithm where one is only paid if in fact DR clearing makes customers better off. The way you do it is to run the 15 minute auction without DR in the stack. You run it with DR in the stack. This will produce 2 numbers, if DR is not in the stack and you have $100 clearing price with DR now you have an $80 clearing price, it looks good. The DR providers get paid because they've reduced the price.

Then you have to factor in the building unit problem. It does affect the price and it's the missing money problem. Just to pick a number, if there has to be a $4 charge to solve the missing money problem, you now have a price to load of $84 with DR in the stack instead of the $100 clearing price without DR in the stack. Customers are still better off paying $84 instead of $100. It's not as good as having them pay $80. By letting DR clear and charging them $84, you've made sure that customers are better off for at least that increment when you run the auctions. This can be done continuously.

Speaker 4: If I could just add to this. You're absolutely right. It could cost consumers more. That's why an ISO or RTO shouldn't pay DR full LMP in all hours no matter what. There needs to be limits in place that ensure that DR is providing a benefit.

Second, that flat spot in the supply curve that was just discussed is not always at low prices, it occurs at higher prices also. Especially as you start to look into constrained zones. My guess is that the BG&E zone is a constrained zone. If so, that flat spot might occur at much higher prices than you would expect. If the demand response is on that flat spot, that's at a high price but it doesn't move the price at all, then the DR wouldn't clear. And they wouldn't pay it.

Question: If DR is only paid when consumer's benefit, there will be stakeholder outcry at least within the PJM context. It's a fundamental shift in how demand response participates in the energy market. Currently they allow demand response to self-schedule similar to generators who may self-schedule in the energy market.

They don't see those settlements for quite some time. Implementing that suggestion is just not feasible. Nor would it be desirable on the part of a lot of the CSPs who seem to wanting to have that option to self-schedule that energy and not have to submit that data right away. In fact 99% of the DR settlements in PJM are through self-scheduled demand response. Putting in a strike price in the real time market and then being so-called dispatched according to that strike price has serious implementation issues.

Question: Speaker 4 observed that we might have 1,000 megawatts of demand response capability but only 14 megawatts of actually demand response that we were getting in the market. The conclusion was that we're not doing enough to support demand response because we could be getting so much more and impacting these high-priced hours. However the top 1% of hours, where we built lots of expensive generating and peaking capacity, has prices that are not much higher than a regular retail bill in Cambridge, Massachusetts. It seems that those prices aren't high enough, which would certainly provoke more demand response. How do we get to a point where we're really getting real demand response?

Speaker 4: We're not getting the demand response that you would expect. A demand response provider can address issues that are barriers for an individual end-use customer. They have to provide equipment, resources to go through the rigorous process of providing a baseline, setting up a system to provide for five minute data. They need to set expectations with the customer, all of the marketing and sales costs involved with signing up, especially small customers.

So a demand response provider still has to recover that money and make enough profit to run a business. One of the ways that regular providers do it is not just the energy market, but also to aggregate revenue streams from the energy market, the reserves market, the capacity market, for an end-use customer. Participating in two or three or four different markets lets them consider revenues from lots of different markets.

Let the demand response providers do the same. They provide that sort of aggregation of revenue service. A financing service that's really difficult for end-use customers to do. Some end-use customers can do this on their own but it's rare.

Question: Wouldn't it be easier to just have the prices go up until people responded?

Speaker 4: So just to focus on New England, take off the $1000 cap on energy prices. Let them go as high as they need to. The primary argument against that is that consumers don't have the ability to respond to that.

My counter-argument to that is pay demand response providers full LMP, give them some relatively small number of years and say, you've told us that at full LMP you can go get demand response for us. Go ahead and do it. There will be a couple thousand megawatts responding to price in some hours, definitely not in all hours. At that point take the price caps off.

Once it's been proven that demand will respond to high prices then there's a strong argument to have price caps go much higher than they are now or to disappear. It probably allows them to get rid of capacity markets as well. It might solve the missing money problem. We need to have this discussion.

Question: There's been a lot of discussion about the challenges of changing consumer behavior with respect to demand response. In February Sandia released a comprehensive report on storage and identified 14 value streams ranging from demand response, time of use, real time pricing, support for renewable generation and a host of ancillary services. The value of those value streams varies widely between the different uses and frequency of use. Is storage complimentary to demand response efforts, or an alternative?

Speaker 2: Assuming property right issues are clarified, they are complimentary. Demand response can promote storage technology because consumers are able to see the price variations. If there are opportunities to use storage to allow them to manage their load in such a way that can shift a load to low price period from high price period and benefit from that, that adds revenue streams to storage.

The concern is that absent the property right then storage can be misused. And in such way to allow load-shifting at the same time among multiple meters with set baselines. A clear property right is necessary to avoid this problem. It's all a question about how to do it. A subsidy doesn't bother me, if it is explicit.

Speaker 1: Storage is less problematic because it's a physical asset whose performance can be measured. A user can also make an arrangement with a utility that will improve distribution for the utility and perhaps get a small payment to the end-user. Storage is a form of physical asset. One can measure how often the storage works, the output of the inverter, the physical flows. There's no counter-intuitive to establish. It's all about supply.

This is true about many things on the demand side. People self generate or generate on-premise, but there's no fallacies and there's no counter-factual to worry about. The transaction rate is what it is. There's no concern that someone is being paid for a product in which they duped someone. Technical devices need to be looked at differently. It's a physical asset, not a virtual asset.

On another issue, we spends thousands of hours a year debating four things in DR. CBL? [customer baseline] How much is enough? How much we should be paid? And implicitly what would people have done otherwise? We perpetrate these questions. In other markets, we don't ask how much acreage of tomatoes should there be. How many acres of wine should be grown, well we all know that's an infinite amount. However, we're asking this question about how much demand response is enough and does it get paid enough? We've broken the basic part of the economic model.

The economic model lives on willingness to pay. Instead of guessing what the market is willing to pay, customers decide. Instead of patronizing customers, they've got to get active like they have in the telephone market. Everybody's buying complex products in the telephone market. Or changing plans because they want day and night, gee how hard is that? They pay more in telephone than they do in electricity. All these efforts are concentrated in the wrong place. We're trying to solve a retail problem at wholesale, and we must change that.

Question: We've heard that demand response should be just another competitor in the market. We've also heard that there should be more competition in DR. Is there a possibility to set some of these issues, specifically how much is paid to DR, in a competitive way? In other words, could participants be bidding in, not just an offer rate you know, when I get dispatch, but how much I get paid when I did get dispatch? That could help set consideration of who gets chosen.

Speaker 1: I hope that it's entirely possible. One would hope that DR competitors would go out and try and steal customers from each other. It's up to the DR provider to figure out how many revenue streams can I get compared with all my costs. What revenues can I get from the energy market by responding to prices? What revenues can I get from the capacity market to responding to reliability events? What revenues can I get from the reserve market? They need to do this like any other competing business model. A customer doesn't see the LMP. The demand response provider is the market participant.

The demand response provider gets paid the LMP. They then negotiate with their customers how much they pay their customers. As an end-use customer if demand response provider 1 is offering me ten bucks and number 2 is offering me 12 bucks, and the ease of switching from one to the next is pretty easy then I'm going to take the 12 bucks every time. So it's up to them to figure out how to bid into the markets to make the amount of money that they need, and how to cover their costs.

Question: We've heard about the notion that one megawatt of supply and one megawatt of demand are always the same. Aside from whether that's actually true all of the time, if that's going to be the underlying assumption then how do we address whether demand response should have to comply with all the same rules, cyber security, market power, NERC rules, environmental rules.

One speaker said that emergency generation would be subject to air permits under the cleaner tailoring rule, you would have the distributed generation qualifying for demand response. It would not have to comply with the proposed greenhouse gas rules, but would still be paid. How do we integrate demand response with the rest of the world we have to live with?

Second, many of the safeguards that have been articulated could be incorporated in a three or four sentence tariff change that would be uniform across all the RTOs. Why does this one element need to be made uniform across all of the RTOs?

Speaker 3: All of the RTOs have two things in common, they are big picture items that suggest the rules should be the same. They all have security constrained economic dispatch and some version of LMP.

The way DR fits into the market, given those two constraints, suggests the rule should be the same across all RTOs. Whatever differences exist among RTOs, they are very small compared to those two bedrock ways of operating. And on your first question, I think many of the rules that apply to generation should apply to DR.

Market monitor scrutiny of DR is appropriate, at least to the same degree as generation. I have trouble imagining DR having market power, but if it's a concern you can look at it. It's not an issue currently. Second, DR tends to be environmentally benign in most instances, but to the extent it has environmental consequences, those rules will apply. In many cases the rules will be similar and they should be.

Speaker 4: I agree. There are many cases where the rules should be very similar. Demand response is not the same as generation, so some of those rules are going to be different.

Question: That's not what's in the proposal on the table. None of that is in the proposal.

Speaker 4: Should they be exactly the same across? I think what the FERC has said is the payment rate is the same. What the NOPR says is that they should be paid LMP. There's eight other questions, especially bidding parameters.

Do I get to bid in for one hour? Do I have to bid in for four hours? There's all sorts of ramp rates and no-load and start-up costs. Those kinds of things the NOPR doesn't touch. Different RTOs would do those things very differently.

Speaker 2: Market monitoring is different for demand and supply. The things that you need to watch, on the supply side is to raise prices, on the demand side is to lower prices. On the demand side you monitor the customer baseline issue and on the supply side there is no customer baseline issue to worry about.

On the second point, demand response is closely connected with both wholesale and retail. The development of the retail market is important. There are variations in New England where the capacity market that has attracted close to 3,000 megawatts of demand response. In areas that have dynamic pricing programs, like California, will have different variations.

Question: My question comes from ERCOT context, which is not only idiosyncratic but maybe not quite FERC-related. In that context there is a huge role for demand response with a very specific context. In scarcity or close-to scarcity conditions, we might expect market power mitigation. Demand is really about getting prices under scarcity conditions up to competitive levels. In other words, getting prices higher. The whole debate this morning is kind of phrased in the opposite direction, but I'd like to hear what the panelists have to say.

Speaker 4: If you were able to have a robust demand response that showed it would respond to price, then it might be entirely acceptable to take off the price caps and allow the price to rise where it would.

Question: Often the pricing rules set price on the last accepted megawatt as opposed to the clearing price. It's the practice of the ISOs not to price at the competitive levels. Further, via market power mitigation, they keep the offers down low. In other words, prices are below competitive. And to me demand participation is the only politically palatable way for prices to get to competitive levels, by having demand be the market participants who set the price. That's the most important role of demand response.

Speaker 4: Now I understand your question a little bit more, thank you. Some actions that the operator takes for reliability are frequently cited as actions that set the price well below where it should be. There are some credible arguments there. It's a market imperfection.

I agree with your point. That to the extent that demand can be robust and can respond to price, a lot of those posturing activities and other activities might be allowed to disappear.

Question: If we ignored all of these programs to encourage demand side management, all of the cost of monitoring, all of the complexity of designing it etc., and simply put in real time meters for the customer classes with large load, so many of these issues would be irrelevant. Is there something I am missing in this statement?

Speaker 4: The answer will depend greatly on which region you're in. Some regions have a large amount of their load coming from single-large loads. New England has less of that than some of the other regions do. The benefit from a simpler solution would depend on how the load looks. I don't know exactly how much, what percentage of the benefit you would get.

Speaker 3: A lot of state commissions are not likely to first, spend the money on advance metering. Second, some state commissions will spend the money on advance metering and then not adopt the rate structure that goes with it. That's the worst of both worlds, but that's political reality. The hypothetical won't happen because there will be a lot of political pressure on the commissions not to have dynamic pricing.

Speaker 1: Ten years ago, the technology wasn't there but it is now. There would be 5 to 7% of customers who are price responsive; everybody else would be hedged up to their ears. There would be no central capacity market. There would be no missing money. There would be no CBL problem. There would be customers; the right amount of generation would come forward.

There would be periods of price volatility; they wouldn't last long because customers would quell them. But they'd be robust enough to have generation resolve them. We would not feel guilty about building a peaker because it serves peoples' willingness to pay. As long as we have excuses, regulators won't do this, then we'll have the same answer.

Question: Even if there is more demand response competition, isn't it possible that residential customers aren't inclined to sign up? They're not that interested in innovating with their electricity bill? Is there some other model for enrolling residential customers to sign up for demand response programs that isn't so reliant on demand response providers?

Speaker 4: Yes. One model, much like state-funded energy efficiency programs that allow either the utility or state-run efficiency, is a state-run demand response utility offering. I worry about that a bit because individual companies competing against each other do a better job with customer service and innovative offerings and technology. They deliver something to the customer that they actually want.

Even though we get annoyed by calls at dinner time by people trying to sell me stuff, if I see that a couple of my neighbors have adopted, a couple of the early adopters have adopted it and are saving money. Then we might see some of the independent programs hitting a successful threshold. So far I'm still convinced that's the best model.

Question: Most of the discussion so far has focused on DR subsidies in the energy market. However, I think there's a big inequity in how we compensate generators versus demand response in the capacity market. As long as they're in the same location we pay them the same yet the generator has a much tougher obligation, it has to bid in the day-ahead market.

Further, in PJM at least, DR is only expected to be called upon a maximum of 10 times. Only in the summer, and each occurrence is for no more than six hours. That's a big inequity. We're paying both of them the same price but for a completely different product.

Speaker 4: Absolutely. The issue of comparability between generation and demand response in the capacity market is critical. In New England the demand response providers have said they would gladly have a must-offer requirement if they could offer into the energy market. They can't do that right now. They would gladly take the peak energy rents in the energy market.

Another concern in New England is that if I'm paying a generator for capacity, if they're out on approved maintenance, they receive a complete pass on that. If they can't respond in shortage hours they get a pass.

Why are we paying for capacity now if in six months when we need it they do not have to provide it. It's possible to have 6, 8, or 9,000 megawatts of generation either offline or unavailable due to start time. All of that is being paid for but is unavailable.

Question: The generator can have a forced outage rate of 5% or less. However, you can't necessarily compare that to calling demand response 10 times during the year. There's a huge inequity there. You're right, sometimes the generator is offline, but if they're offline during a peak period they're losing a lot of money. They have every incentive to be available.

Speaker 2: One has to define the product very carefully. To the extent that both demand and supply fulfill an expectation as a substitute then they deserve the same payment. That's a basic market principle.

On the supply side there are a portfolio of supply technologies that are different. They all get paid in the same way. Demand is certainly different from supply. It does not have setup cost, it's different from a generator. It has other characteristics like how long it can actually last. The product definition in the capacity market is specifically for the shortage hour. As long as that they can fulfill that obligation ISO will pay them.

Now whether this is sufficient and complete characterization of the service is an open question. Demand response can participate in energy, capacity, ancillary services, and regulation markets. There is a question of completeness, of the design so that it covers all the attributes that demand resources can offer. As far as capacity market is concerned, it can be designed in such a way that demand and supply offer substitute products to fulfill a specific product definition.

Comment: Many of these comments and arguments should be set aside to address a foundational question. We have to make a choice between objective welfare maximization in the short and long run, or minimizing the payments that customers make in the and long run? They are not the same thing at all but the tendency is to confuse the two. Each path leads to very different kinds of policies. The problem is that we have to choose, and most of the time people in the industry act as if they are the same thing. It's an important issue, The industry needs to be aware that we are making a clear choice.

Session Two.
Financial Reform: Intended and Unintended Consequences

Financial regulatory reform has implications for the electricity industry. There is a high likelihood that derivatives will be regulated in some form. Which derivative products in electricity markets will be regulated? FTR's? Fuel Hedges? Price Hedges? Others? If they are regulated, what will that regulation look like and what effect will it have on the power sector? One of the most frequently discussed regulatory mechanisms with regard to derivatives is the mandatory imposition of a clearinghouse through which trade will have to be cleared. What are the implications of such a requirement? What role, if any, will ISOs play in that regard? How important is the distinction between hedging and speculation? Who will be the regulator, FERC and CFTC or some hybrid? How will credit requirements interact with banking reform? Are there unintended side effects of financial reform?

Speaker 1.

This issue is so broad-reaching, even if you're not going to buy or sell power in the next year, one will be impacted by this. FTRs [financial transmission rights] are involved in a jurisdictional tug of war between the CFTC and FERC. The question is will CFTC determine that they are a jurisdictional product? If they are a jurisdictional product, will FERC continue to argue they are just and reasonable? If they're not just and reasonable what happens to them? They can't be sold under a FERC tariff and we're left wondering what happens to auction revenue rights, how do all these things get managed, is there a revenue shortfall, how do underlying load servers monetize this stuff, how do they get it off their books? These are big questions.

We can talk about this issue in a lot of complicated terms. We can talk about re-hypothecation of capital, letters of credit, all sorts of things that might change the way we do business. These issues can affect our day to day life. Does anyone post variation margin on their house to their bank? No. If you had posted variation margin on your house to your bank would we have had the mortgage crisis that we have now? You certainly would have seen it coming and there certainly wouldn't be a backlog of foreclosures because there'd be a lot of people in default on their variation margin.

A mortgage down payment is in some sense the initial margin. When banks lowered that initial margin they increased the risk. When they liquidated Lehman on the Exchange they never even got through a third of their initial margin. They were cleared. So I'm not going to stand here and say there's no benefit to clearing. The question is, is it always right to clear? Do we need to clear all this stuff? Do we need to kind of look at energy?

So that said, why are we even thinking about this? It's because the nation's lack of posting of variation margin on our houses, our lack of requirements of initial margin or down payment on our houses created a mortgage problem. The inability to value the underlying credit default swaps created a problem in that market. Folks wound up trading a bunch of things that reasonable and smart people couldn't agree on what they were worth when they went to liquidate them, that meant there was no market to liquidate them. Ultimately this is about systemic risk.

Does energy create any systemic risk? That is the key question for this panel. Please remember too, that clearing will not eliminate the risk. You don't actually get rid of risk, you manage it. If we force clearing, in some sense the industry is trading counter-party risk for liquidity risk. It's not getting rid of the risk, it's just changing it.

From here on, I'll talk about this question from the perspective of a large energy trading and supplier company. If an energy supplier goes to serve a municipal load, a full requirements customer, that load isn't flat. It's got peaks and valleys that are served by a combination of base load, combined cycle, and peaking. The rest is generally supplied by chunks of 50 megawatt blocks of commonly traded power. Now these peaks and valleys don't always go off in 50-megawatt increments. So the supplier will wind up a little bit long and a little bit short. They sell these amounts all the time. The risk with financial reform is that packaging and reselling those small increments is likely to get the supplier tagged as a swap dealer. They're managing and mitigating risk using swaps.

Why do other people want this done? Well, in essence power is nothing but a heat rate derivative to the underlying fuel. There's that ugly word, derivative. Power is a heat rate derivative. Natural gas is the most volatile commodity that's traded, thus companies that use its energy are a heat rate derivative to it, an expansion of that volatility. Customers that don't want to wear that risk got to the energy supplier and trader.

There are several issues involved in power and OTC reform and whether energy suppliers should be included. First, people differ on the value of a credit default swap but the value of power is pretty straightforward. In a restructured market it follows a dispatch curve regulated by FERC and administered by an RTO. One can know the value of that power by walking up the dispatch curve. This means that the risk of fuzzy valuation is far less. The value of power is clearly defined, just walk up a dispatch curve and we know what we're dealing with.

Second, power suppliers work in a very regulated market. Whether restructured or non-restructured, electricity is the only market that is price-regulated in terms of a ceiling. Not like an agricultural commodity where there's a floor, but a ceiling. When a supplier bids into the provider of last resort or the SOS auction in Maryland, or into the basic generation service auction in New Jersey, they make an assessment of whether the bid is out of market. There have been auctions in Maryland where the whole auction's been thrown out because they thought everyone bid too high.

The last time we had a real liquidity crisis was when Enron went down. The change in the bid/ask spread was roughly about $2.00. For New Jersey that results to about a $200 million dollar a year increase in price, in total cost. That's non-trivial. That's 20,000 megawatts of total load just for New Jersey. EEI has estimated something like $200 to $400 million in just margin would have to be posted by every utility in the country. This is a ton of money.

In the wholesale market they're regulated by FERC, and every ISO has a market monitor. At the retail level they're regulated by the states. All of this is important because designation as a swap dealer could potentially force energy suppliers to clear, and ultimately to eliminate many of their bilateral lines. It basically imposes a lot of costs that they don't currently have. One way to think about this is if all of your credit cards were wiped out and you lived on whatever was in your bank account every day.

Ostensibly, a company's credit should be managed by their balance sheet, but in some sense that balance sheet is managed by the hard value of their underlying assets, whether they're Chesapeake Natural Gas or Constellation Energy, it's managed by the cash they hold on their balance sheet and by their cash flow position. When they are required to post cash or get letters of credit to post for margin the cost structure is changed. The problem is that power suppliers, particularly ones that trade extensively, are some of the largest retailers of power in the country. They serve much of the Fortune 500 and they serve them on low price.

The proposed bill doesn't draw clear lines between FERC and CFTC. Companies will be subject to dual enforcement, dual compliance, that again increases costs. If they are a major swap participant or a swap dealer they will have all sorts of reporting obligations and increased back office costs. In this economic climate, significant cost increases, especially for companies that compete on cost, are a serious concern.

The Dodd bill creates new definitions of swap dealers. We've had a Securities and Exchange Act that's had a clear definition of a swap dealer for a long time. Now electricity traders will be swap dealers or futures commissions merchants.

Clearing is useful, many transactions are cleared by suppliers. There is a concern for moral hazard that we're creating for our DCOs. [derivatives clearing organizations] The current bill say if a DCO accepts a product to be cleared it must be cleared. So what's their incentive? To clear everything. Right? To the extent that they feel they can manage the risk, they get money for clearing a supplier. If they clear a very thinly-traded product and someone goes bust who do you liquidate it to? What is the underlying value? Can reasonable minds differ if it's thinly traded? Think about the SO2 market. A 100-ton trade moves the SO2 market $20, $30, $40, it can double it, right? We saw that happen at the end of last year when the court reinstated care and somebody window-dressed their NOX book to the tune of $6,000 for annual NOX. Annual NOX is now trading $400. They traded only 200 tons to get it up to $6,000. It was a Merry Christmas for them, you know? I hope they got paid a nice bonus on that.

These new rules could create a race to the bottom. I'm worried about the incentives that it's going to create, similar to the banks that we saw, of lowering the amount one had to put down on their house? Are they going to lower the initial margin until there is just a concentration of risk. Currently, there is diffuse risk with many counter parties. A company manages credit risk by setting up diffuse risk among many counter parties? Now there'll be one entity holding a ton of risk and competing for all this business. This legislation could unintentionally create a concentration of risk. Senator Dodd worries about it, too because you'll see that clearinghouses will now be able to access Fed funds. This legislation will institutionalize the bailout. If DCOs concentrate risk and fail they'll be able to borrow the money from the Fed.

Finally, consider the exclusion of Forex in the bills and the fact that commodities are 1% of all traded OTC derivatives. Why are the energy suppliers included in this legislation? Even the crude market is not that much. Forex is huge, CDS [credit default swaps] is huge and it's not clear why energy players are a part of this.

Speaker 2.

I'll address a financial derivatives perspective within the financial reform and its effect on energy derivatives and the energy sector. I'll try to explain the legislation and come up with some answers. It's sort of a Herculean task, at least with respect to the energy sector. There's some very good questions as to whether the intent of the legislation is to come up with answers or there's some other agenda with respect to regulating energy derivatives. I'll give a brief overview to navigate some of the terms and the structure to get everyone up to speed for a useful conversation.

The Senate will be closing debate on a bill jointly sponsored by the agricultural committee under Blanche Lincoln and the banking committee under Senator Dodd. I'll focus on that bill although there is a bill out of the house under Barney Frank, and they will have to be resolved.

The existing federal regulatory framework for over the counter derivatives and energy derivatives was set in 2000 with amendments to the Commodities Exchange Act through the Commodity Futures Modernization Act of 2000. This created different categories of commodities and designated some categories as exempt, including metals and energy. Except for certain anti-fraud and anti-manipulation provisions they were exempt from regulation and pre-empted from state regulation, state bucket shop and gaming laws. On the regulatory front, that legislation was concurrent with predominant FERC jurisdiction.

Now how is that landscape going to be changed? All the bills, have four ways that they intend to regulate derivatives. The first is regulation focused on specific types of transactions. Is this a type of transaction that is subject to this regulation? The second would be whether an entity is regulated by a different regulator. That's why we've been hearing the term swap dealer or major swap participant. Third, there are provisions regarding transparency disclosure in reporting. Fourth, there's regulatory oversight and enhanced enforcement capability on the part of the CFTC and the SEC.

I'm going to be focusing on provisions that apply to energy derivatives, which the bill gives to the CFTC, not the SEC. Only to the extent that there are energy-linked securities, or derivatives that embody securities that are linked to energy products does the SEC have jurisdiction.

The first question is whether a transaction is a swap. Essentially a swap of payments which is conveyed on an executory basis without conveying an ownership interest in the underlying commodity is a swap. The Lincoln bill excludes any sale of a commodity for future delivery, or forwards, or any sale of a non-financial commodity or security for deferred payment or delivery, so long as the transaction is intended to be physically settled. Well, those are somewhat elastic definitions. There are some more elastic provisions, ambiguous provisions, elsewhere in the act than this. Cash-settled, natural gas and oil options swaps would fall within this definition.

The more difficult questions are with respect to physically-settled swaps. What if there was an exclusion if a swap was intended to be physically settled? What if the swap itself has features for physical and cash settlement? How do you determine whether the intent was for physical settlement? What criteria does one require to determine the intent?

There are practical problems like book-outs. Book-outs occur when two parties settle their obligations with a cash payment even though the contract may provide for physical settlement. Would that be an exclusion from physical settlement? FTRs, if you look at the definition of swaps in legislation, are swaps. On the other hand they're based on physical attributes of the transmission system. They're not derived from an underlying asset and a notional amount that has no relationship to the amount of the physical asset that's being traded or settled.

The second broad question for transaction-based regulation is if it's a swap, is it regulated? Is the transaction regulated? There's a clearing requirement, unless an exclusion applies you have to clear it. What is the exclusion? There's a mandatory exclusion for anything that a clearinghouse will accept for clearing, which is vague.

Under most variations of the bills there is an exclusion for commercial end users. This has been the subject of much debate in the energy sector. The definition from the bill that's now pending is an energy company is not a financial entity, it's a commercial end user. Its primary business activity is that it owns, uses, produces, manufactures, goods, services or commodities, including coal, natural gas, electricity, crude oil, gasoline, propane and other hydrocarbons.

At first that looks pretty good. However, the commercial end user can't be a major swap participant, which I'll come to later. It must use the swap to hedge its own commercial risk. Well, that's a concern for power marketers or generators, whether they're actually using the transaction to hedge their own commercial risk, especially if there is excess capacity that they may be selling or trading away. It must be the primary business activity. An affiliate of a commercial end user, so a power marketing arm of a generator or utility, may use the exemption if the affiliate is an agent and is using the exemption to hedge or mitigate the commercial risk of the commercial end user affiliates.

This brings us back to the question then, what is a commercial end user? And again, there is an issue as to whether regional transmission organizations and ISOs would have to clear as well. The implications of having to clear are higher margin requirements and a less liquid market. Many companies pledge physical assets in order to meet their trading obligations. I'm not clear whether a clearinghouse can margin a power plant or some other physical assets. That might be somewhat difficult.

Further, is the entity regulated? Remember, a major swap participant is an entity that maintains a substantial position in swaps for any of the major swap categories determined by the SEC or CFTC. The definition of a substantial threshold that they determine to be prudent for the effective monitoring, management and oversight of entities that are systemically important or can significantly impact the financial system of the U.S. So there's still a lot of discretion on the part of the CFTC to determine what is substantial. The test is not necessarily whether what they're doing leads to greater price transparency and stability in the energy markets or in other markets. The substantiality test excludes positions for hedging or mitigating commercial risk. An eligible contract participant will have to be registered. There will be disclosure requirements including capital and margin requirements, business conduct and compliance standards. this is another layer of regulatory oversight.

It's not clear whether the ISOs and RTOs have to be regulated as derivatives clearing organizations. If one considers the definition of FTRs and some other ancillary products then it's possible that they would be deemed to be DCOs, which would have business conduct standards and registration requirements in addition to what they may also have under other state and federal law, including FERC.

Transparency and disclosure pretty much applies to all types of swaps, whether they are required to be cleared or not, or traded by a major swap participant. If they're not required to be cleared and even if neither one is a major swap participant or dealer, even if they're bilateral parties they have to report. There will be a new swap repository, which must meet certain criteria that will aggregate the data and report it to CFTC and SEC. If entities do not follow these regulations, there will be penalties but the contracts will still be in place, they will not become null and void.

The fourth issue is the concern for concurrent regulation. The act sets out jurisdictional boundaries between banking regulators, which are called prudential regulators, and the CFTC. FERC is not defined as a prudential regulator. There's no express jurisdictional limits set forth between the FERC and the SEC and CFTC. Some versions of the bill an M.O.U. between the two agencies to set out their respective jurisdictions.

There has been suggestion for a specific exemption for electricity products and services under a FERC-approved tariff should be exempt. It hasn't been added to the current draft and Chairman Gensler of the CFTC has vociferously argued against it. He argues that if you create such a bright line exemption it may create loopholes. That may strike someone as counter-intuitive.

Let's bring this all together. The topic of the panel was unintended consequences. Will the next AIG come from the energy sector? Alternately, critics of the legislation from the energy sector argue that it's a solution in search of a problem and it can lead to regulatory application to products with no connection to the financial crisis.

There are certain ambiguities that are a concern for the legislation. There are always ambiguities. Further, there are some key definitions in the act that need to be further defined and guidance provided. Some of these should be addressed clearly in the statute, rather than left to regulatory interpretation.

Again, the consequences of uncertainty and enforcement could be less liquidity, higher costs for consumers. We may lose track of whether rates are just and reasonable.

Question: The swap repository, could you explain what they are? Would this be something like Platts or an agency-run database?

Speaker 2: Not run by a federal agency. It's anticipated to be a private entity. It would have to be independent from SWAP dealers. It could be an affiliate of a clearinghouse, which would be the most logical to service that function, or an exchange.

Speaker 3.

I'm going to talk about the value of a derivatives clearing organization and the value of clearing in terms of managing risk. Clearing is a good thing. It adds a lot of value to the system.

Currently we have electric power futures exchanges that do financially settled contracts. They're an exempt commercial market as defined by the CFTC. Let's talk a bit about Nodal Exchange as an example. They offer 1,800 locations on a very granular basis. It is all the hubs and zones as well as all the generation nodes in the Eastern ISOs, and more recently in California.

They have two platforms because there's so many different locations rather than use a live trading model. They use an auction-based approach. All the owners are in by 11:00, results are back by 1:00 PM. It's a blind Dutch auction, works a lot like the FTR auctions, but it's a direct match. So it's a mini-to-mini match, but you always have to have someone on the opposite side. There has to be an exact match in terms of the contracts that are there.

They also have the counter market too, where you can submit trades where you just submit it to be cleared until you get function. The central counter-party is the London clearing house [now LCH.Clearnet] – so Nodal is horizontally integrated. London clears a lot of exchanges in Europe, as well as other places around the globe.

Often a house will take some time until they are able to work in a given market. When Nodal did California, they launched in May 2008 but didn't go operational until April of 2009. London wanted them to have at least one year of data to look at, so they understand the volatility of those contracts, and could ensure that the risk was properly handled.

If LCH.Clearnet was here, they would argue that a clearing house should not be clearing everything. So to answer one of the questions, should we clear generation? Absolutely not. It should be standardized contracts. London does extensive analysis before they let a company like Nodal introduce a new product.

There is a question of horizontal versus vertically cleared models. A horizontal model separates those two functions, Nodal does not decide the margining in the exchange, LCH does. They're the central counter-party.

When the LCH does margins, they do an initial margin and a variation margin. The variation margin is that the price was, say, originally around $50 and then the price moves, so there's a variance for that, so it's a price for against.

So you're either given or take cash you have to put in based on that variance. Separately, there's an initial margin. An initial margin is there because if in fact somebody does default, the idea is the defaulters post a pay and they have enough cash there. There's a variance margin portion, but they won't be able to get out of those contracts immediately, it may take them a few days to do that. They look back at the history, look at the probability of the variance of that price could be over in that time period. They've got enough cash for those couple of days in order to get out of those contracts, so they can move it off their books. They don't actually want to be a party to any trade when that happens.

So when Lehman Brothers went down they had been in existence since the late 1800s. They'd never had a situation when any of their counterparties had not been paid on a contract in their entire history. LCH had $10 trillion of default by Lehman Brothers, because they were a large clearing house. They used a variation margin to start, because that's the difference in the price of those contracts. But then you have the initial margin left to go through. On the initial margin, which is the next thing they would go to, LCH used a third of the initial margin to get out. They took the other two thirds of the initial margin and paid that back to Lehman Brothers creditors. Anybody who was a counter-party to Lehman that had traded through on a cleared basis, was protected. As was the system. So that's why a clearing house process is believed to be a fairly safe process.

Nodal Exchange uses value at risk [VaR] as its approach for margining as opposed to SPAN. [Standardized Portfolio Analysis of Risk] SPAN is great for one contract. When you have 1,800 different locations and many different expirees, SPAN would break down because it wouldn't give you any of the offsetting benefits for all these different contracts, which are truly there. So VaR becomes more accurate in that situation, and it's more capital efficient. This is because they use bar methodology. Nodal's margin is based on the positions that a participants get, not bids into the auction.

The market failures were not just a question of regulating credit default swaps, the heart of the financial crisis. The issue ultimately is, it's not the product itself. It's that the fact that there was no accounting for counter-party risk, there was no margining in it. Warren Buffett argued in 2002 that derivatives were essentially a time bomb because of this counter-party risk dimension.

So AIG had business with a variety of different parties. If and when AIG went down and there was no support for them, then their counter-parties, which were stuck in bi-lateral transactions, they would've likely fallen as well. Eventually the banks would've gone down and we would've had a pretty bad situation. The proposed solution, rather than bailing out the banks and AIG, is to create an environment where the defaulter ultimately pays and is able to because they have been cleared.

In a margining environment it's the defaulter that pays. When Lehman went down, LCH had rights to that cash there, they used that. LCH ultimately paid for the moving and the unwinding of the transactions. Not the other parties, the counter-parties, on the other side. It's that approach that is appealing to a lot of people to prevent a future financial crisis.

Although this reform impetus came out of credit default swaps, and not out of energy, some have argued we should reform the whole thing. This is not just an American perspective, the G20 leaders met in Pittsburgh last September and said they wanted to have all standardized OTC [over-the-counter] derivative contracts traded through exchanges, where appropriate. Of course there's a lot in that word, where "appropriate."

The G20 also said that OTC derivatives should be reported in trade repositories, and that's a transparency issue. Further, non cleared contracts should be subject to even higher capital requirements. Because if you're going to put it off exchange then, they're worried there's other risks there. They wanted to put capital requirements in here.

So Congress has been trying to get something potentially passed. The big questions have to do with the shades of gray, the questions of what's standardized. Some contracts are certainly clearly standardized, but there are many in a gray zone where it's hard to determine if they are a custom transaction, a non-standard transaction. So far the definition is, "will a DCO choose to clear this product?" For LCH it's got to be a pre-defined standardized contract.

Then there's the question of whether one is a major SWAP participant? We heard about that from the previous speaker. and are you one or are you not? The third major question or gray area has to do with whether the trade is for hedging, or for speculation. These three areas are real questions – standardized trades, swap participants, and hedging. There are no clear definitions for any of them yet. The problem is that this means that there are many players who do not know if they will be subject to this regulation or not.

If legislation does pass, we will have to hear from the CFTC to provide clear definitions. It's really not clear what entities are going to do, especially those that are in a wide variety of bilateral transactions. Those transactions are "off-exchange" and could be subject to clearing, or to increased capitalization and reporting requirements. Clearly these are complex issues. Not everything should be cleared, but I certainly think that having good faith efforts to clear in these shades of grey may be appropriate. Doing nothing at all and saying, well everything we do is completely customized, I'll never clear. That would be a problematic position. Alternately, if you're a large power supplier that often clears many transactions, they're obviously in a good position to say, we make judgment calls, we have a history of doing that.

The benefits of clearing are tied to systemic risk. Participants have access to a wider range of participants, and it eliminates the need to monitor your counter-parties, and assess the credit aspect.

From the LCH Clearance perspective, they don't have to understand the credit risk of all different parties. Instead, the initial position is determined. In order for a participant to get onto this position, they need this much cash. If they have this much cash, and they have the variance margin, they can get onto this position. If things are moving LCH will ask for more margin, you don't provide it, they liquidate you. From that perspective they don't need to actually know, do they think you're going to go down or not go down? That's how that system works. The total transaction cost including the default risk, may be lower than a bilateral transaction.

Clearing also allows netting of positions, which has benefits as well. First there are more participants. If you look at the top 50 participants in the FTR markets, they represent 95% of the volume cleared. If you look at them on a volume-weighted basis to see how they are rated by the agencies, 45% are rated great, 7% are rated BA3 on the cusp, 8% are rated not investment great, and 40% are not rated at all.

If an entity only wanted to work with those who are rated investment-grade, that would wipe out half the volume on the FTR markets in terms of who you could have as your counter-party. The following logic is that that you're probably not getting the best price. Because you don't have as much competition for what you're doing. If entities can hedge via transactions that's better, and if they can do their transactions with more parties that's better also.

Second, in a bilateral transaction, an entity needs to monitor their counter-party. This is difficult when there are downgrades and a bad economy. Typically there's a batch of entities that are going to be downgraded at the same time. Rating downgrades can occur suddenly, and affect a large part of the sector. Monitoring this is difficult.

I had a recent conversation with a municipal entity asking whether they were clearing or not. They don't clear any transactions today. If they have a default they will charge their rate-payers more. They'll just pass it along. They figured they could handle one large default. The problem is that it could be 3-4 or more. There is a serious risk there for their ratepayers.

What will regulators do who are looking at regulated utilities that want to trade? They may say I'm not going to clear anything because I'm hedging. What do you do as a regulator? Do you say, that I'm still going to put that in a rate-basis? All their default risk?

These are the issues for entities that are choosing not to clear. Consider the transaction cost, which should include an estimate of default risk, right? If you're in a credit business you have to put some estimate of a loan loss. If I do a bilateral transaction I'm not reserving for loan losses, and that is another expense that should be on the books. You're exposing yourself. The committee of chief risk officers put out a paper in February 2006, before the financial crisis. Their estimate was that 84 basis points should be the amount of default risk to include in a bilateral transaction. As they analyzed it was more than the cost of doing the cleared transactions.

From an economic standpoint if you assign that cost or had a reserve for it, clearing is cheaper than doing a bilateral transaction on an economic basis. If you choose not to reserve for it, and just let it hit you then you're not going to have that visible risk and so maybe it'll look cheaper, but it really isn't cheaper in the long run. My example of that is Hurricane Katrina. Category five hurricanes can hit New Orleans. The levee could withhold up to a category three hurricane. Levees for a category 4 or 5 were too expensive.

Katrina was category four when it hit the city of New Orleans. Lots of folks are unwilling to buy insurance, but defaults can hit very hard.

Similarly, I'm sure British Petroleum wishes they'd done more to manage risk. The cost of that is just enormous. Insurance programs are cost beneficial and that is the way that clearing should be perceived. I would not want to be experiencing the pain that they are feeling right now.

Fourth, if a company has many bilateral transactions they can't net them out because they're with different entities. If they have a central counterparty which is the one party I'm actually trading with, because all my trades are with that entity, then in fact a company can net out its position properly. In a web of bilateral transactions, a firm can get a bit stuck. If somebody goes down, they're caught in this web. So netting out is a big value of central counterparty clearing.

Let's take a look at jurisdictional issues for FTRs. FTR markets were created for two reasons, one is congestion revenue distribution, and the second is providing the ability to hedge. There's a lot of concern about whether FTRs will be under FERC or CFTC jurisdiction. We've heard some examples of the socialized credit dimension that exists in case of PJM. With Lehman Brothers there was socialized money.

The clean climate act in June of 2009 had derivatives legislation in which the FTR and energy markets would be carved out and remain under FERC. The newer legislation did not have the carve out and it looked like FTRs might go under CFTC.

The CFTC certainly isn't going to want to back off, they need to protect their authority to regulate. However, they don't really want to be regulating FTRs, etc. On the other hand they don't want an explicit separate carve-out either. I expect the legislation will imply that the CFTC has broad jurisdiction, but then exempt the FTR markets to FERC. I think that's how it'll fall out. That would solve part of the Gordian knot. I expect the two agencies will share between the two. I've been in joint meetings as an exchange. They have sharing arrangements and there is communication obviously.

In that situation, participants have the option to clear. If the ISOs function as the counter-party to these transactions, what could happen is that on the option of the participant, against their other option, they could choose to clear. The ISO, since they're on the other side of it, they would clear it too, the transactions would then go into something like a Nodal Exchange or LCH.clearnet. They could do this very easily. There are other entities that also provide a service similar to this. At that point, all that has to happen is the ISOs have to effectively become participants in the exchange. Almost everything could be handled with straight suggestion contracts. The CFTC might like this because they still oversee the clearing organization and the exchange. They may mandate somebody who they think is a financial player to clear, so that there is an avenue to clear. This scenario would handle their need without having them getting into the specifics of what happens within the FTR auctions. The FERC can go on exactly how they do today. This is just one scenario, but there are many other possibilities obviously. Hopefully I've clarified some of the possible ambiguities.

Question: You've used the term clearing over and over, and I'm not quite sure exactly what that is and what happens. Can you explain what clearing actually involves and is it a one-time thing? Is it done every day? Is it done once a month?

Speaker 3: It is like an auction cleared. In this sense it's financial clearing. The key dimension of it is that LCH.clearnet is going to ultimately oversee the transaction that has occurred. If two parties negotiate a transaction, and they say I want to do this transaction together, and they submit it over the counter for clearing, what it means is they're basically choosing to do a transaction together simultaneously that says that their legal responsibilities of party A and part B are not with each other.

Party A does a trade with the central counter-party, and party B does a trade with the central counter-party, which is equal and opposite.

Question: Do they have to do that together?

Speaker 3: It has to be done simultaneously, and it has to completely match. Because the central counter-party wants to take absolutely zero market risk, they're not taking a position either way. All that's left is the credit risk with each side. The way they handle the credit risk depends if the market is a commercial exempt market, you have to be an eligible commercial entity.

Now firms are certain to be able to trade in the market. The clearing house will margin the two parties separately to ensure that they're not really at risk if one of them goes down. They can make their obligations and move the transactions out. They use a process called novation where they become the party to both party A and party B. At that point Party A doesn't care if they did a deal with party B at all, it's irrelevant, for them it only matters that it's being handled through the clearing house. In these situations Party A will never know who was on the other side of the transaction. That's all anonymous. All you know is that you were awarded volume, and what LCH.Clearnet ends up with is always an equal and opposite position of whatever gets submitted today. It's deemed cleared because it's novated by the clearinghouse and they're the party in the middle.

Speaker 4.

The purpose of financial reform is to address the big picture. Regulatory lapses, failures, gaps, and everything that led to the financial meltdown. The Federal Reserve is really supposed to be dealing with these big picture credit default swaps, AIGs, Lehman, etc.

Consequently, it is a priority for the Obama Administration to enact this piece of legislation. The impact on the electric and gas sectors is really a flea on the tail on the dog. They're really not worrying about FTRs and RTOs. The electricity world is exceedingly complex, they're looking at a different world, and we're really an afterthought in all of this.

So both the House and the Senate bills will have unintended. Consider utilities like Exelon, a big utility based in Chicago, about five million customers, more than anybody else among 15 million people. They are tiny compared to these other large entities such as Goldman Sachs. In general, the electricity world would like to see financial reform succeed and get enacted, but please don't screw things up for us. The energy industry has not posed the types of systemic risks, that we've seen in the AIG and TARP world. They are a small portion of the derivatives trading in this world. They're not the Warren Buffett candidate for mandatory oversight and clearing because they are already regulated by FERC, by the NRC, by the SEC and by 51 state regulatory commissions, or in the case of munis and co-ops by the states directly.

The sector has been united in its approach to the legislation. This includes firms like the American Gas Association, American Public Gas Association, American Public Power Association, the American Wind Energy Association, Compete, Edison Electric Institute, Electric Power Supply Association, the Independent Petroleum Association of America, The at-large Public Power Council, and the Natural Gas Supply Association all have a common position.

The electricity industry and the financial industry don't talk well to one another. That's one of the issues. The industry has been seeking a commercial and user exemption from CFTC oversight. The industry does hedge its risk. They engage in transactions with other counterparties, in swaps and derivatives transactions. That's how we hedge our risks. They choose to use bilateral transactions with strict credit requirements from a power team or take a transaction through an exchange. Mandatory clearing is not needed.

One of the power teams of a utility I work with has looked at these issues extensively, with financial experts. Their estimate is that it could cost $1 billion for this utility, a large utility. This is not trivial. That means that rates would go up anywhere between 5 and 15%. This is not an insignificant thing. Even though they are the flea on the tail of the dog of this financial reform bill, it's a big deal to us. The industry is also worried about whether the CFTC's authority under its exclusive jurisdiction would override other jurisdictions, like FERC's or the Natural Gas Act, the Federal Power Act, the Energy Policy Act, of various years particularly 2005. They don't like the idea of having yet another regulator in our business.

So far this has been a very difficult battle. I underestimated it when I first got involved with it. The toxicity of the discussion between the FERC and the CFTC has been strong. They have not been playing nicely with one another of late. They have different goals, different objectives, different cultures, different ways they approach the world. The just and reasonable standard means something to me. It may not mean something to the CFTC.

The legislation also has lots of different committees on the Hill that are involved in it. Barney Frank's Committee, the Agriculture Committee, and the Energy and Commerce Committee. At the Senate it's the Banking Committee, the Agriculture Committee, and the Energy and Natural Resources Committee. It complicates matters intensely.

In the House-passed bill, the industry did make progress on a hedging exemption there. They punted on the relationship between the CFTC and FERC in the House-passed bill, they simply called for an MOU. It's kind of hard if you're FERC, and you're dealing with somebody else who has exclusive jurisdiction. The Senate bill is still very much up in the air. It looks like there will be a least dual jurisdiction in the Senate bill that preserves FERC's authority notwithstanding the CFTC's exclusive jurisdiction.

The clause preserving FERC's jurisdiction does not affect the CFTC's authority over trading, execution, or clearing of contracts on a registered entity including a derivatives clearing organization. The amendment also requires the CFTC to grant exemptions from its requirements for FERC-regulated contracts if the CFTC finds an exemption to be in the public interest, and consistent with the purposes of the commodity exchange act.

There's a difference between may and shall in legislative drafting. It's going to be a very long time before the CFTC decides they need to give up jurisdiction. We would have preferred an exemption that said FERC transactions shall be exempt unless the CFTC determines that such transactions pose systemic risk. Congress is desperately afraid of creating regulatory loopholes. The bill is likely to perpetuate overlapping and messy jurisdictional oversight.

I'm not sure they'll have a conference. They may try and work out things informally between the leadership. They do a lot of that these days because conferences are a public spectacle and very ugly in Washington. There's a possibility that the House will take the Senate-passed bill, which they didn't like doing a whole lot on health care as you recall. I do believe that the bill be enacted this year.

Question: So you're saying that the bill is being constructed with exclusive jurisdiction for the CFTC without exemptions for energy. This will create all kinds of unintended consequences but it will then be the CFTC's fault and it won't be the Congress' fault? Is that what it boils down to?

Speaker 4: Not quite. The modified Bingaman-Murkowski amendment says that CFTC exclusive jurisdiction shall not pre-empt FERC's jurisdiction under the Power Act or the Gas Act. They'll both be in charge.

Speaker 5.

The issue just discussed by the previous speaker still leaves the question of if the CFTC has *exclusive* jurisdiction then what conceivable jurisdiction can FERC have, right?

Let's take a look at the history of this mess. When the first centralized derivatives contract was traded on the Chicago board of trade, they allowed users of that market to offset their grain delivery contracts and pass money back and forth depending upon the outcome. That was the beginning of the centralized derivatives trading in the United States. Almost immediately the farming community got a whole lot of angst. There is a severe tension between the agricultural community and guys in Chicago with gold chains who trade their little hearts out. It was always the hope of the agriculture community that these markets be brought under some kind of federal regulation, i.e. the Department of Agriculture. For 60 years the exchanges fought that off.

During those 60 years they were avoiding federal regulation a whole separate community of little entrepreneurs developed around these markets. They set up shops and said, hey, you don't have to go to those pesky exchanges. They got all these rules, we'll do the deal with you privately.

That set up over the counter derivatives. That went on for 60 years, and it annoyed the exchanges because the little guys were eating their lunch. Finally in 1921 Congress began to regulate these markets. The agricultural community developed some muscle. The exchanges said come under federal regulation with good terms if you get rid of those pesky bucket shops. They did, and from 1922 until the late 1980s over the counter derivatives trading in the United States was banned. The CFTC has never said that swaps are not futures contracts.

In the Depression, the Secretary of Agriculture went to the exchanges and said we need clearinghouses. Record-keeping but also some cash behind it. These were the first clearing-houses.

So how do they work? Let me be the customer. I open an account at Merrill Lynch. The broker says, glad to have you as a customer, first we need initial margin. The exchange sets initial margin, let's say you need $1,500 per contract, how many contracts do you want? I want two, I give them $3000 up front, and if I start losing money on this trade I'll hear from the broker again.

If I go underwater on the transactions I have to pay more money, or default. It is highly unlikely that I am ever going to default unless I am absolutely broke because my broker is going to sue my socks off. I'm going to owe interest on that debit balance and I got to pay some expensive lawyer to defend me. As long as I can afford to pay, I will pay.

So let's take the worst-case scenario and I go broke. At that point who's responsible, then? My broker is responsible. That's why he's been bugging me for margin all this time. He's responsible, and has a license from the government that says they have to maintain a minimum net capital at all times. They will be able to cover my losses.

The broker will pay, too, because that debt will stay with them unless they go bankrupt as well. So let's assume that the broker is bankrupt. Well, the clearinghouse doesn't want to deal with this mid-tier broker. They want to deal with a firm that they have vetted themselves and that meets their standards.

So this intermediary called a clearing member, is sitting on boatloads of money. He then has to take responsibility for my loss. Should that fail, and once again there's a very large financial institution going bankrupt, only then does the clearinghouse have any responsibility for that loss. There are several layers of protection, and hundreds of millions of dollars before the clearinghouse has to do anything. There's shock-absorbers along the system.

The clearinghouse does three things, it makes sure that its own clearing members have a lot of money. Second, they make sure that when those tickets come into the clearinghouse – on an interest rate trade or a copper trade – there's a matched transaction. They'll report that back to the clearing member that these lock. Third, they will have their clearing members contribute to a pool of funds, it's a guarantee fund. At the CME Group [Nymex owners], they have about $2 billion in guarantee funds on any given day. They have assessment authority to more than double that at any time.

Since the clearinghouses were first formed in the thirties there has never been a loss left unpaid in the futures markets. Never. The Lehman failure was a perfect example of the stress that this system can bear. In the late eighties the swap business started, the earliest were inter-bank, interest rate swaps. Now it's a $600 trillion business.

Some people say that they're going to get swamped with costs if they get entangled in the traditional futures labyrinth. I have two arguments for that concern. First, whether you collateralize it or not, you've got the risk. I would argue that many of the bilateral agreements in the power business are non-collateralized risk. The risk is there. The damage will not be less because you ignored it, Second, the way the system works, hedgers generally get substantially more attractive margins than speculators. Now, you don't get dollar-for-dollar because futures prices deviate from cash prices sometimes, and particularly in times of stress they can get substantially different. Or the underlying commodity may already be committed for sale to somebody else. Or as soon as someone hears that there's some stress in the system they may start trying to get bargain prices out of you.

There are ways in which hedging situations can become uncoupled. Hedging margins always take into account that you have the underlying product and they always give you a better deal on margin than you would get as a speculator. Further, I'm not aware of a single clearinghouse that will not take treasuries as margin. So a power firm is not losing money, they can even make a little. It wouldn't amount to much but you could actually make a dime or two by depositing treasuries. Now admittedly, those funds are not available to go so somewhere else. There is an opportunity cost for sure. However, in terms of out-of-pocket cash cost, there are ways to reduce that pain as well.

My own view on the legislation is that it's too big. I do want the CFTC to have exclusive jurisdiction. It is incredibly important to have a single regulator with general oversight. A firm should only have its compliance people or your outside law firm have to deal with a single regulatory entity.

Further, derivatives trading is a hologram, it's a financial let's pretend. It's an insurance policy, or a speculation tool. It's a way to offset risk. In terms of the legislation I suspect the Senate will be very quick but the conference committee will be like Custer's Last Stand. There will be a lot of bickering. The thing to remember is that under this legislation is your money and my money. My retirement plan died a sad death in the last two years, because folks were free to trade without any collateral backing those trades.

Question: It's still not clear to me why energy is involved in this. We heard that what happened to AIG wasn't about the product, it was about the counter-party. Others argue that maybe that isn't so. The difference is that the energy product is heavily regulated. It's not that we don't have the risks, but it's the question of the type of collateral that gets split up.

No one addresses the question of, if you clear, how do you post the power-plan or things of that nature? There's no reason we should be treated like credit default swaps when we're not. Why should energy even be included in this discussion, based on the fact that we're trying to address what happened with the financial markets? I still haven't heard a clear answer why that's the case.

Speaker 3: Here is why it probably happened. The credit default swaps raise the concern for the insurance surrounding them. Those trades were possible without any collateral. AIG was taking on all the successive risk, and when things moved quickly they weren't able to have the defaulter pay, because there was no cash in the system. It was going to create a large, domino effect. The government needed to support them in order to prevent that. It all came out of a lack of counter-party risk, it wasn't the swaps themselves.

The government is concerned that large scale financial trades should not happen without collateralization, a way to ensure that if some players start defaulting then the financial system is not at stake. They are concerned it might happen in other commodities, so we need to have a global, overarching approach.

To your point, energy was not involved at all in the cause of any of this. Nonetheless, there is a concern for attempting to reduce the systemic risk overall. So look at energy in terms of bilateral transactions, and a lot of those are with the same financial banks like Lehman Brothers.

The government is concerned that it is not meaningful to address the risk by only addressing credit default swaps. They want to address financial risk across the board.

Question: There is an implication that what the power industry is doing is not collateralized, when it is. The industry is going to have dead capital that's going to make it harder for us to invest in infrastructure and our business, and those costs will be passed on to consumers.

Speaker 3: Well, non-standard contracts aren't necessarily going to be cleared anyway, right? They do not want to take non-standard items and try to clear those. However, contracts that are standardized so it reduces the overall risk should be so that we don't have large-magnitude cascading events. A lot of those contracts in the energy business still won't change.

Speaker 2: The problem with AIG was not the type of product, but the fact that that it was an unregulated entity. Insurance is regulated, but it was deemed that credit default swaps were not insurance. So that slipped through the cracks, it wasn't adequately capitalized. That should be the criteria for financial reform regulation, is there a functional regulator that's doing the job? Is the industry adequately capitalized as a whole? That should be the guiding light in terms of having a surgical approach to legislation.

Question: When you've got a product that it's hard to determine the actual value of, or the exposure of it, or to determine the proper collateralization. In the energy market, there's currently proposals to eliminate unsecured credit and FTRs. That doesn't solve the problem of defaults, right? It puts a little more money in to cover the potential default, but if the evaluation is wrong and the exposure is wrong, you can still have a default. In part it is about the things that were traded and the way they were traded.

Speaker 2: Remember, there's never been a situation where the counter-party in a cleared transaction was not ultimately paid. It's about the participants but also the clearing banks. A Lehman Brothers can go down but when Lehman did go down it was in fact, handled.

Question: It doesn't make sense for small participants in the market to have certain risk policies. It makes sense for some of the big banks. That would solve some of this without imposing costs on everyone. While clearing is good and helpful in some cases, there are a lot of reasons for other market participants to do bilateral contracts. You might want to be able to do both. As a small participant you're probably not imposing too much risk on the system.

Speaker 5: Most of the regulated markets, as well as the clearinghouses, have risk management requirements. They audit on a regular basis. It's about show me the money.

There are economists advising Congress on how to deal with the tweaking problem, where parties take standard contracts and change them so that they look a little strange. That way, they do not have to put it on exchange or clear it. Some economists are trying to decompose hypothetical swaps and identify all of the features that are standardized, that are parallel to what the exchanges are trading. They might then split unique contracts in two so that the standardized part can be traded and cleared and only the tail end remains over the counter. It may be that you do a deal and find it re-engineered for the sake of conforming with the regulatory standards. Not the economics of course, but the structure.

Question: In terms of FTRs, why should I care about this problem? I mean, if it turns out that the collateral that people are setting up isn't sufficient and if the CFTC does a better job and they have a better way of measuring the collateral, then that is a good thing.

I do worry about financial regulators who don't understand the electricity market. They say well this is just a hedging contract, the market can provide this. We don't need to have the ISO and the RTO involved in this. What they don't understand is that when you have an FTR auction, the net position that has to be measured to be simultaneously feasible. This is what the RTO, ISO is taking the obligation for. They are perfectly hedged by the congestion rentals that they're going to collect in the time frame coming forward.

The RTO has costless hedge because of the nature of the way this market works. If you take them out of that business then you're actually introducing risk by separating all these FTRs. One can end up with people saying an FTR is unrelated, is separate, they need collateral for that. However, in fact, it's a complicated portfolio that all fits together with the congestion rental. Is the CFTC going to unravel that whole brilliantly designed system? Or is it going to leave it untouched?

Speaker 4: The CFTC does not want to regulate FTRs. People think they can understand FTRs, because there's this notion that they're physical, but they look a lot like a derivative product because the value of it is derived from the congestion revenue and the physical aspect of it. FTRs have become the poster child for what FERC should have and the CFTC shouldn't. The CFTC wants to continue to have NYMEX and ICE. In return for NYMEX and ICE statutory oversight, the CFTC might give up FTR oversight. However, the CFTC has not wanted to make that deal in the discussions.

You should worry. No one in those legislative negotiations would understand what you just said.

Fast forward to another critical question, are capacity markets derivative products? Are the RTOs themselves clearing organizations? They do a lot of settlements. Hopefully this will get worked out in the rulemaking process to implement the legislation.

Speaker 3: In my discussions with the CFTC commissioners, they've indicated they will exempt the FTR markets. They don't want to get into that market, but they also don't want to vacate responsibility or lose their broad mandate.

Speaker 4: I'm not convinced that's true for the Chairman.

Speaker 3: That's probably true.

Moderator: I'm actually not sure the ISOs understand all the risks. Are they properly collateralizing? I don't know if that's always true. It's a challenging task and so one question is, should they be in the credit business?

Certainly, they're almost like a gas producer because they have the intrinsic asset that they're selling. However, there's a lot of other participants in those FTR auctions who don't, who go short. There have been problems. I don't know if it's a systemic problem. A lot of the FTR stuff is a sideshow. There is an opportunity to increase liquidity by doing more standardization and more clearing.

The big issue for the industry won't be the FTRs, but bilateral contracts. It's a big volume and there is counter-party risk. There is the same networking of contracts that we see in the financial services industry. Financial services are heavy participants in that business. The banks were and are big traders in energy. When they suffer, this industry suffers too. So what do we do when there is an illiquid, non-transparent network of obligations with exposures that don't add up.

Question: How do we calculate additional costs? I'm trying to understand how different players that a utility relies on for collateral will behave in the market. Can letters of credit be used? What happens to certain kinds of transactions like coaling contracts? What are the components of costs?

Speaker 4: You have to post collateral and margin on a daily basis. If money or securities tied up there and not elsewhere that's a constraint. Utilities do many transactions while applying their credit criteria to their counter-parties, but there's no margining requirement.

In garden variety trading with no derivative products there is no requirement to post collateral, so if that is added the costs will be large.

Speaker 3: Costs will include some loss of credit lines to bilateral counter-parties, and things like that. The EEI study said there's 200 utilities with an average of 200 to 400 million for each one. It's a lot of money. Cargill threw a $1 billion of initial margin out there on the table. It's big money.

Question: We heard that VAR is sometimes used to determine what margin requirements are. What did you base that on to get probabilities and magnitudes of losses, how often is the calculation run? There is discussion in the financial markets that VAR is a limited risk evaluation technique. The concerns are black swans and fat tails and distributions and the like. Does none of that apply to this business, in terms of risk assessment?

Speaker 3: Well, the margining for Nodal Exchange is done by LCH.Clearnet. They this on many other markets. There's two pieces to the value at risk approach. There's the variance, and then there's the initial margin. The variance margin is how the price moves, and the money that is put up. The initial margin is supposed to cover the concern for default and the fact that it has to be liquidated. Is there enough money to ensure it is covered as it's liquidated.

In Lehman Brothers case with the $10 trillion portfolio they only used a third of the initial margin – there was ample space. It's supposed to be money sufficient to cover that. With value at risk they set the number of days needed to unwind a portfolio. They use the case, past history, and other factors to determine that. Nodal looks at the price movement over a year long period. They ensure that the price movement over those number of days with a standard deviation around it to as close to 100% coverage as possible. If prices move rapidly in a few days as they are trying to sell off the portfolio, they're not hurt by the movement in prices. That's what the initial margin is intended to cover.

They use as much history as available. They look at the entire history to determine if they want to participate in a market. In the case of California, though they had knowledge of how LMP had operated in other markets, they knew it was a different market. The volatility is going to be different. They waited a full year to watch that market before they were able to jump in the game.

Question: You didn't answer my question about the black swans and the fat tails.

Speaker 3: I'm not able to answer those concerns, my assumption is that they have allowed for those.

Speaker 5: Both are good if properly seasoned. [Laughter]

Question: Has anybody thought through the cashing out of the FTR process? There's only enough money to cash out the FTRs. Sometimes there's a revenue shortfall, there can theoretically even be a revenue gain.

Each one of the ISOs has their own set of rules for how you make up that shortfall or gain. I know of no analogy in any of the financial markets to that type of situation. What would it would mean for the CFTC to go in and regulate those transactions with all those rules that are based on the physical topology of the network?

Speaker 3: I don't think anyone has thought of that issue.

Speaker 4: Some of the folks who do the support work for the ISO RTO counsel have tried to get a handle on this. I doubt they have a real detailed kind of estimate, and I have not heard that anyone at the CFTC has thought about this issue either.

Speaker 2: I would be surprised if this has been addressed seriously. Shortfalls are a particularly troubling problem because they pay a person differently if they go short than if they go long. It creates market inefficiencies. The industry should do something to eliminate shortfalls in the ISO markets, independent of financial regulation.

Question: Well, they have a methodology for making up the revenues.

Speaker 2: Well, in MISO they make it up by charging APR holders, which means they have a shortfall. They just move the shortfall around.

Question: It's like a clearinghouse where they collectively make up the shortfall of the market post.

Speaker 2: That's more of a semantic fix than a substantive one. The point remains, we should have contracts that settle against a single index, rather than two. Like, if you go long or short, the price should be the same.

Question: I was intrigued by the discussion on the cost that the industry would have to absorb. We heard a figure of 200 plus firms each with $200 million plus of impact, plus substantial logistic compliances. Extra collateralization or of margin. However, I'm also hearing that there is very little systemic risk in the power markets. Are those contradictory statements?

Speaker 4: They are not contradictory. Large scale transactions require some margin requirements to address risk, outside of the fact of systemic risk for a certain sector. The regulatory requirements are what they are.

Speaker 5: The exchanges reserve the right to change their margin requirements at any time. Sleepy little contracts that don't change much in value have far smaller margin requirements than something very volatile like gold. Similarly oats will have smaller margin than oil.

Speaker 4: What about electricity futures?

Speaker 5: They're not volatile at all. [Laughter]

Speaker 2: Your argument is that in a rush to standardization for clearing, the industry'll lose the customization associated with bilateral OTC derivatives that they can customize and be adequately collateralized. One you move it onto the exchange, both oranges and apples have to be made into an orange. It's going to take more collateral to do that.

Question: FERC takes steps in the credit area. Some have argued for a connection between the controversy that's the subject of this panel and a previous rulemaking that started at FERC. They proposed substantial increases in credit requirements for doing business with the RTO. They're suggesting a move to weekly settlements and eventually daily settlements. They're proposing that all FTRs have to be collateralized. Is there a tie between FERC's actions and the current move for financial oversight?

Question: The simple elimination of unsecured credit in FTR markets is wrong-headed. It doesn't address the problem. The problem with FTRs is to get the evaluation and the exposure evaluated correctly.

Eliminating unsecured FTR credit just puts more money in the pool for when someone goes bust. It doesn't necessarily ensure that they'll be sufficient funds when they do go bust. It's very similar to our consumer credit market.

That said, there's a lot of good in that credit NOPR. There shouldn't be a broad mandate to put the ISO as essential clearing party. Clearing is good, but it shouldn't apply across the board. Companies need choices to manage their risk without over-insuring. For example, how many people flew to this conference? Did anyone buy flight insurance? It's not a risk we choose to insure.

The way we need to look at this is, what are the risks we want to insure? Are they systemic? Can they be absorbed? Can we walk away from them? The large amount of collateral that the industry would be forced to post versus the diversified bilateral risk that they currently wear, is a contradiction.

If a company has a diffuse set of counter-parties it's hard to say they can't manage risk. If they're assessing counter-parties and pledging collateral assets that you can foreclose against, that has value to it. The industry knows how to value those assets.

Session Three.
Renewable Energy: Prices, Costs, and Carbon Emissions

Renewable energy is a policy choice for reasons relating to the environment and national security. In electricity markets, what impact will renewable resources have on price signals? Government subsidies (including, but certainly not limited to RPS requirements), zero marginal costs, uncertainty of supply (particularly in regard to wind), increased demand for backup power sources, and other such realities of renewable energy, will inevitably impact the price signals generated in the market. Will they have the effect of lowering prices and thereby reduce the incentives for conservation and energy efficiency, thus contributing to the consumption of more electricity than might have occurred with a more traditional resource portfolio?

Conversely, will enhanced need for reliability stimulate more distributed generation that will more efficiently deliver ancillary services into the marketplace? In regard to carbon, it seems intuitive that increased reliance on non-emitting resources will have the effect of reducing overall emissions. Is that commonly accepted intuition true? What sources of energy, for example, are most likely to be displaced by renewables? Will it be low emitting natural gas, or baseload coal? How cost effective is the promotion of renewable energy as a means of reducing carbon emissions, as compared with cap and trade schemes or carbon and/or energy taxes? Are RPS and cap and trade compatible? In short, what policies and methods would make renewable energy a cost effective vehicle for reducing carbon emissions?

Speaker 1.

This presentation focuses on ERCOT in Texas. In many respects ERCOT is an outlier in U.S. markets, a self-contained interconnection. In the context of wind it's useful because it is a canary in the coal mine. They have limited hydro, and virtually no pumped storage, so the problems of wind are at their most challenging there.

The U.S. is building a ton of wind, and the implications should be examined. Presumably we're building renewables to reduce greenhouse emissions. I want to explore how increasing wind, transmission constraints, various subsidies like renewable credits, and transmission constraints function with wind intermittency, carbon prices and electricity market prices in ERCOT.

Texas has peak demand around 63 gigawatts, and 73 gigawatts of generation. They have four zones for transmission and are going to nodal very soon, fingers crossed. Most of the zones have even generation and demand, but Houston relies on imports to meet its peak demand. The west is where all the wind is, and the people ain't. There's about 13 gigawatts in the west zone, and half is wind.

The problem is export constraints. When the wind blows, the west zone price is very different from the other three zones. One would expect the prices would be at marginal cost. The trick is figuring out what the marginal cost is for wind because of PTCs [production tax credits] and regulations. However, the effective marginal cost is about minus $30 when there is little demand and lots of wind.

I've done some research in Australia which has a virtually identical situation and market setup. So on one particular day last year, their prices went down to about minus 400 Australian dollars which is maybe about minus 350, 300 U.S. dollars per megawatt hour.

So what's the implication of that? Those differences in zonal prices or nodal prices reflect the opportunity cost of transmitting power. In other words, that is the cost of providing transmission. When the transmission constraints bind we'd expect that price difference to be high, and it's as much as $40 of megawatt hour or more, from the west zone to the Texas demand centers in ERCOT. Obviously, it's even more from south Australia to Victoria. As an opportunity cost the transportation cost of $40 a megawatt hour is a significant fraction of the typical price in ERCOT. This is a big cost in an energy market.

In the longer term we can fix transmission problems. For California that's very, very long term. In Texas it's moderately long term because it turns out it's much easier to build transmission. They have fewer environmental restrictions for transmission.

In principle what one would do is trade off the socially optimal transmission expansion that balanced out cost of new transmission, new wind generation costs. This would include the build costs, fuel cost savings, maybe even the savings from greenhouse, and maybe the reduction in new generation because of the wind availability. Of course in practice no one does transmission planning like that. For one, production cost savings are really hard to estimate. Further, transmission planning is driven by other goals, right? In the past, we typically thought of transmission cost as small because it was at most maybe 100 miles or 200 miles away from the demand center. Wind requires much more transmission, and large amounts of capability.

In ERCOT they're building five billion dollars worth of transmission that will enable an additional 11 gigawatts of wind. Depending on how you amortize that you'll come out with different figures. I estimate with a 40% capacity factor, about $20 a megawatt hour. I take the total cost of the transmission, and the energy that's transferred over the lifetime of the project, and calculate net present value. It's an average cost, not a marginal cost.

There are some concerns about view-sheds west of Austin but more than likely these lines will be built. Once that's happened, more wind will get built. One serious problem is that onshore wind like west Texas' does not correlate with demand. It tends to blow more in the winter, the spring, the fall, much less in the summer when it's really needed. There's no nice coastal breeze to cool you down. The policy direction in Texas is to build a ton of onshore wind. More Texas wind will create more low prices off-peak.

This has important implications. Let's look at one day in 2009. From 2 a.m. to 5:30 a.m. prices throughout ERCOT went negative. That happened for about 30 hours in 2009, and it will occur more as they build out the transmission and build more wind. When the price is $30 in west but not everywhere else, it's the wind setting the price, and there's not much thermal online. OK. When the price is minus 30 throughout ERCOT every thermal generator in Texas that's left online is also paying $30 of megawatt hour to get rid of its energy, OK.

More wind under those times should force certain generators to shut down and start up again. However, they may be happy to pay to have their energy taken away, because presumably the costs, meaning primarily the fuel and greenhouse gas emissions, of shutting down and starting up again would be even greater.

Thus, during those hours, those generators are increasing their fossil fuel use and greenhouse gas production. It's serious issue that we need to think very carefully about.

So far, the story's not all terrible because part of this is driven by the fact that thermal generators don't necessarily know very well when they should have shut off. Currently those unit commitment decisions are decentralized. When they go to a nodal market, they will have day ahead unit commitment at the same time, and that will make things a good deal better. However, it also means they need to be able to forecast accurately. If the wind is still blowing a lot for five or six hours it's unlikely that they're going to be able to shut down the coal plants for five or six hours anyway. So it still may not solve the problem.

Even though the transmission upgrade is designed to avoid wind curtailment, they're probably going to spill some more wind under some circumstances. As they get more wind they need to think about net load. The implication is they will eventually need less base load. The short term implication is that coal might be getting most of its operating cost except when the prices are negative, but it's likely not to receive very good remuneration. Now that to me means don't build anymore coal in Texas. However, several asset owners are building new coal in Texas, which seems crazy.

The story is more complicated because of intermittency. Variability means that additional costs to account for it and address it will be in the zero to five dollars per megawatt hour level. However if they go to even more aggressive standards, it's more complicated. If they have a 30% renewable portfolio standard that could easily translate into 26 gigs of wind. So when we get 26 gigs of wind and it blows off peak that's going to be more than minimum demand. They're going to have to store many, many gigawatts. This is a huge issue in terms of implications of operations.

It's going to involve more reserves, more agile peaking and cycling, probably more wind spillage, and a bunch of other investments. I don't know exactly how to calculate what that is. My wild guess is 5 to $10 a megawatt hour. These costs significantly impact what they will pay for carbon.

There are some caveats. ERCOT socializes all transmission costs. North American markets generally socialize ancillary service costs despite causation altered load. I've included those costs and also subsidies to thermal generation as well. The typical unsubsidized cost of wind energy is about $80 a megawatt hour. If we have $20 incremental transmission, 5 to $10 proxy for cost of intermittency, it comes to about a 105 to $110 per megawatt hour.

The bottom line is that wind adds about $50 a megawatt hour to the costs of what you would otherwise have paid with the existing thermal system. That is just 110 minus 60, the cost for thermal. So if we're adding wind to displace carbon dioxide, the value of that carbon dioxide better be better be worth more than $50 a megawatt hour. Waxman Markey numbers were starting off 13 to $14 per U.S. ton. It translates to a value of carbon dioxide displaced when we displace coal, of about 15 to $35 worth of carbon dioxide per megawatt hour. However, it's going to cost Texas 50 bucks to do it.

That number is only if wind is displacing coal. However, the ERCOT evidence suggests that new wind may not even be displacing greenhouse gas use, they may be running it anyway, it might be making it worse. Even when wind only displaces coal, and we don't worry about the fact that it is still running, I'll put that aside. I'll assume that wind displaces fossil and in particular displaces coal, and it's still not worth it given the Waxman Markey bill or any equivalent legislation. We have to rethink the costs to deal with greenhouse, or thinking about something other than wind, like perhaps solar.

We need to be thinking in a more coherent manner about what the policy is trying to achieve. If we're trying to achieve renewables then this might make sense. However, if we're trying to achieve greenhouse gas reduction then this approach is not going to be so useful.

Question: Does the ancillary service cost include uplift cost. So besides balancing and maybe more voltage, but also when there is negative costs off peak, some coal units may have to be kept online. That is an uplift that gets socialized on load, and it is usually not captured in the ancillary service cost. That cost is higher each year because of wind integration.

Speaker 1: That cost is not addressed in most studies. Sometimes it's covered in unit commitment cost. A lot of the estimation is using tools that were designed for dispatchable generation, and they don't cope very well with nondispatchable generation. There have not been many truly disinterested studies on this.

Question: To confirm you're data shows that at least in the future an increase in wind generation will increase the retirement of coal units and reduce the construction of future coal plants.

Speaker 1: Yes, 100% sure. That is a different aspect of the story. Right now increasing wind is having some perverse effects.

Speaker 2.

I'll give some background on what's been happening with wind energy. Then I'll attempt to demonstrate why wind has been so useful, focusing on the perspective of many who produce wind.

Global wind growth has grown precipitously over the last three or four years. The U.S. has 35 gigawatts installed right now. China and Europe are both very advanced. In the U.S., 40% of added capacity is wind, with gas making up the bulk of the remainder. The best resources are in a belt from the Dakotas down to Texas. Columbia Gorge and Wyoming are also good. There's a great amount of wind in upstate New York. Texas is the leader.

There is about 300,000 megawatts of wind in queue, almost ten times the amount of the installed wind we have. There's uniform agreement that transmission is the big obstacle.

There's been a gradual downward trend in the installed capacity cost the last couple of years as commodity prices have decreased, exchange rate issues have waned, and simple supply and demand for turbine parts has decreased. We'll probably see a fairly flat trend going forward. Wind is in the 50 to $60 per megawatt hour range. It follows the prevailing electricity prices from region to region.

Most wind is developed by independent power producers, who build and own the project. There is some wind that's developed by utilities, it's usually about 20%. It's sold as a mixture of merchant and other forms of agreements. A typical arrangement is that the majority is secured through a PPA [purchasing power agreement] with a utility, and the remainder on the merchant market. The PPA is a critical step for getting financing for many projects because it provides price certainty and credibility.

Let's examine wind's role in reducing carbon emissions, for benefiting consumers, reducing electricity prices, and the question of the cost effectiveness of wind as a carbon emissions tool. The Department of Energy's 20% Wind Report from 2008 showed that half that wind was offsetting coal, and half was offsetting gas. That study did not use a detailed power system model in terms of the ramp rate capabilities or other aspects of the energy market.

There is a significant savings for natural gas via offsetting but also depressing natural gas prices by decreasing natural gas demands. This is not just limited to the electric sector, it has broad applications for the economy since natural gas is an important component for heating and many industrial processes. There is a significant benefit in terms of displacing coal. The DOE report showed wind's contribution to reducing carbon emissions at 20% was almost a third of what was necessary. Wind is not going to solve all of our climate problems. Further, if we do get a carbon price, wind has the potential to save $98 billion dollars in carbon costs following the assumptions of their study.

NREL and DOE conducted the Eastern Wind Integration And Transmission Study, a more in-depth study of wind with much better modeling of the power stamp include ramp rate, minimum turndown levels for generators, all the critical issues for a realistic look at how wind is going to affect the power system. It shows wind almost exclusively displacing coal power. This has a lot to do with the ramp rate issues, and the minimum turndown levels for coal. The study looked at 20% and 30% wind in the eastern interconnections.

There are concerns about building transmission to access wind. These include concerns among environmentalists that coal power would be able to use those transmission lines to expand its market footprint. However, if wind is displacing coal, then it is unlikely to come online. Wind is a very effective tool at forcing those coal plants offline, and there are significant carbon emissions reductions.

The same study examined the capacity value of wind energy; the capability of wind to meet peak demand. It is a concern but when examined across a broad geographic region, you get a very robust capacity value when you aggregate the wind over the entire eastern interconnection at a 25 to 30% range. One of the groundbreaking results of the study is that when we aggregate wind over a large area, a significant capacity value emerges for wind energy.

Let's discuss the cycling and ramp rates for coal being discussed by the first speaker. Excel Public Service Colorado examined the costs for cycling a coal plant, and the answer was that the vast majority of the costs are O&M [operations and maintenance] costs, basically wear and tear on the boiler and other mechanical equipment as you cycle them. The thermal stress of turning a plant on and off is the bulk of the cost. The fuel costs were a very small share of the total cycling cost for coal. There are not significant emissions from cycling coal. The more important point is that in the long term, as you add more wind, the long term effect is displacing coal since coal plants.

A third study is the western integration study. With high cost gas the study shows that obviously wind mostly displaces gas. In a 30% wind case there is a 25% reduction in carbon emissions because wind is mostly displacing gas and not coal. As the amount of wind goes up the marginal impact on emissions goes up. As you go deeper into the generation stack you start displacing more coal. If gas prices are lower, then wind displaces a lot more coal. At 30% wind you get a 45% CO2 reduction, more similar to the eastern wind integration study.

Other studies have looked at this. each of ISOs has done their own study and there is DOE EIA data for Colorado and Texas. They all demonstrate the same thing: a lock step change in emissions of carbon and other pollutants as wind is added to the grid. There is a strong carbon reduction benefit of wind, and all these studies indicate that.

On to the consumer, the cost side. A large number of studies done by EIA, the Union of Concerned Scientists, and several other groups look at the impact of RESs or RPSs renewable requirements in terms of electricity prices, natural gas prices. All these studies show a strong reduction in electricity prices and natural gas prices from an RES as well as carbon emissions. This is because wind displaces gas, and it's cheaper than gas. It reduces the clearing price in the market and that drives prices down which benefits consumers.

Transmission costs should not just be assigned to wind. There are broad benefits of transmission, it improves reliability, it allows consumers to act, and provides lower cost generation not just from wind. Consumers are paying tens of billions of dollars a year in congestion costs. That's why these costs are so often socialized. Most studies that have looked at integration costs, say the number is under five dollars, and that's for 20% wind integration, or penetration.

The Texas case is unique because there is so much wind, and because they're almost exclusively driving off gas simply because the gas makes up so much of the stack there. It will be a different scenario in other parts of the country. There'd be more carbon emissions than you see in Texas.

So, an RES or RPS with significant wind can help reduce the cost impact on consumers while addressing carbon at the same time. There are a number of externalities that aren't really accounted for. With reduced natural gas there are price savings but also water use savings, job creation. If we add up all these externalities from renewable energy deployment it's a strong economic case.

Question: I do know that in a couple of those studies, for instance in PJM, the reductions in LMP costs did not determine whether the assumed wind was actually viable. There was 15 gigawatts in it, and it may be that that much wind is not viable. That's an important consideration.

Speaker 2: Yes, I agree.

Question: In the wind integration studies what was the assumption about the price of carbon that everybody was paying?

Speaker 2: I think DOE used a $25 per ton value, I think the western study used $30.

Speaker 3.

I'm going to discuss the impacts of climate policies and address the renewable portfolio standard or a renewable standard, or a clean energy standard. One of the things that makes it difficult to talk about the economic and market impacts of a renewable energy standard is a creeping baseline. Normally we like to do studies by assuming a no policy case, that is what the world would be like without a policy for a particular problem. We can't do that with renewable energy standards because over the past decade or so they have been put in place piecemeal at the state level. If we're trying to figure the cost of a nationwide 20% renewable portfolio standard. Well it'd depend, if we take as our baseline current policy, then every time another state adds a renewable portfolio standard it reduces market effects and reduces the cost of going from that status quo to a federal 20% renewable portfolio standard.

We are close to that now. With the exception of the southeast, a large number of states have a renewable energy standard of some kind. I'm not engaging the debate about wind directly because these are renewable standards. In different states they include different things. For example Pennsylvania includes waste coal in its definition of a renewable resource. In other cases residential solar gets extra credits. In all of these states there is some form of an alternative compliance payment or an opportunity to use energy efficiency programs as credits against the renewable portfolio standard.

If all of these state programs were confined to renewable as it's defined in Waxman Markey we would be very close to the federal RP, to a federal standard of 20% RPS. An awful lot is not wind. Biomass is an increasingly economic to satisfy the renewable portfolio standards. We shouldn't make conclusions about how wind trades off against other fossil resources if wind and biomass are able to work together as dual renewables. Wind and solar may be intermittent but biomass isn't.

The analysis I want to discuss does not look at the issue of intermittency. It does suggest that renewable portfolio standards would be displacing gas fired generation more than coal fired generation. Wind is favored by renewable portfolio standards, the production tax credit, and additional tax incentives in the stimulus package. They make a significant difference.

Recent analysis by Charles River Associates looked at the Waxman Markey bill. It assumed federal 20% renewable portfolio standard, with several alternative baselines. In these scenarios, gas use drops, not coal. It shows that gas is replaced by a combination of renewables and coal, and that overall carbon outputs increase.

All three RPS scenarios show a slight increase in coal fired generation. Why is this happening? It occurs because of a specific technology mandate that is taken independent of the price of carbon. When we apply renewable portfolio standards they drive down the price of carbon allowances.

It displaces gas, something that mitigates greenhouse gas emissions. When you take out that most expensive marginal way of reducing greenhouse gas emissions, the carbon price falls. When the carbon price falls, coal does better in its competition against natural gas. It creates a perverse effect of having an RPS that drives down the price of carbon, and the price of gas, and increases the use of coal. It changes the carbon price in a way that actually allows coal to do better against natural gas.

There's no change in carbon because the context for the analysis is a Waxman Markey world where the CO2 emissions are limited by the cap. There are two other interactions but they're less important. Under Waxman Markey the analysis also reflects some effects of additional purchases of offsets from overseas when we make mitigation more expensive domestically, or fewer purchases of offsets. There's also banking between the current and the future because all of these renewable policies really have most of their effect over the next decade or so. By 2030 it is so hard to meet the Waxman Markey targets that they would push the country beyond the 20% renewable requirement. More than 20% renewables comes from improved biomass, not through pushing wind beyond the limits that intermittency places on its economic potential.

As a result the renewable portfolio standards in this context increase electric sector emissions of criteria pollutants. With no RPS under Waxman Markey there are significantly less sulfur, NOx and mercury emissions. CO2 emissions are about the same. If we are trying to design an overall carbon policy the balance between emission reductions inside and outside the electric sector have to be considered. The renewable portfolio standard is biased toward more reductions in the electric sector than is economic.

Reducing the cost of natural gas is not an externality. Reducing the price of electricity is not an externality. Creating jobs is not an externality either. Those may be things that one wants to point to but they do not justify an adjustment in prices in order to achieve an efficient market outcome.

Let's talk about the differences of RPS plus a cap and trade, versus a pure cap and trade program. Waxman Markey does exactly what you would expect it to do. Under Waxman Markey natural gas and coal fired generation remain constant for a decade. It reduces the growth in coal fired generation that we would otherwise see. With an RPS there is more reduction in gas fired generation and a great deal more increase in coal fired generation relative to what a cap and trade program alone.

A renewable standard is not a substitute for a carbon policy. A federal renewable standard is a very large distributional change. A federal RPS creates a national trading program in those renewable resources. It brings about large transfers to the states that have wind resources and are already building renewable. They get the money and it comes from the states that have little renewables. California costs more simply because it is so large.

Now let's talk about California. A recent study requested by the California Air Resources Board looked at the effects of implementing California's cap, AB 32. A large part of that study was to assess the scoping plan, because California has appointed an economic and allocation advisory committee. They wanted to look at how much the command and control regulations in the scoping plan were affecting costs relative to a pure cap and trade system.

They constructed four different scenarios. There was one scenario with the scoping plan that includes the renewable portfolio standard, and made the assumptions that the California Air Resources Board was making about the costs of future low carbon technologies. One without a renewable portfolio standard, and then another set of scenarios with different assumptions about the cost of future low carbon technologies. It creates four scenarios overall.

The renewable portfolio standard is requiring the use of renewable up to a certain amount, even if other options can achieve the same CO2 reductions at a lower cost. Remember California has a cap. The RPS is turning renewable generation from being an out of the money resource into a must run resource. It pushes the entire generation stack, or the entire marginal abatement cost curve for emissions to the right, meaning that there is a lower price for carbon, with higher costs overall to society. It is an inescapable result of putting an effective renewable portfolio standard into effect.

One can debate whether it's a good idea for other reasons but there is no question that the effect works that way for the initial short term. The California results demonstrated this clearly in the analysis for CARB.

An RPS increased the costs of meeting the AB 32 targets by about 50%. With different technology assumptions about the cost of new technology, the increase in cost from an RPS is larger, you see even higher increases. The risks of being wrong about technology in the future are much greater if policy locks in some of those specific technologies than if they allow some flexibility. A cap and trade program allows for technology flexibility, whereas an RPS is much less flexible.

This is a serious issue, with high cost risks if we adopt a carbon policy that is technology rigid. We are moving rapidly away from putting a single uniform price on carbon and toward a conglomerate of energy bills that will mandate one technology and incentivize another technology and give DOE a lot of money to demonstrate a third technology. It's a disturbing exercise in rent seeking by interest groups and politicians. It's an example of roadmap type thinking about climate policy that is fundamentally misguided. It's saying we're going to choose the roots today that will solve a social and economic problem that's going to last 30 or 40 years.

To achieve 80% reduction in emissions from the electric sector or the economy we're going to have to rely on technologies we don't have today. We get there through routes that stimulate that innovation across the board. One of the things that can come out of these kind of modeling exercises and analysis is showing that this kind of mandates and standards approaches is a significantly more costly and less innovative approach than letting the market do it.

Question: How was wind modeled in the scenarios? Some of the DOE studies quoted have an average offset to load for wind generation. Is that the kind of the methodology used in the Charles River studies?

Speaker 3: Not quite. They used a model of the entire economy. It includes fuel supplies and supply curves through natural gas and demand responses. On the electricity side in addition to the different resources competing, there are about 20 load blocks. Suppliers are competing in different load blocks, and wind is competing in each of those load blocks against a different resource.

On the cost side they add in a certain amount of gas turbine capacity that has to be built along with the wind. There's an upper limit modeled for the amount of wind that can be tolerated due to the intermittency problems. They're working on detailed wind distribution and frequency data to match up better between the wind distribution and our load blocks.

Question: What price for carbon did they use?

Speaker 3: Price comes out of their modeling. It was starting in the neighborhood of 20 to $25 a metric ton of CO_2 rising at five percent real per year, starting in 2012.

Question: At one point it looks like Texas loses money under a federal RPS but I thought Texas has more wind renewable. That seems odd to me that, it seems like they've got an oversupply so why would they lose money under the situation.

Speaker 3: I think Oklahoma may be soaking it up.

Speaker 4.

Let's examine Europe which has a large carbon market, and the equivalent of federal renewable standard. Europe has legislation in place that would require 20% of all energy and final consumption to come from renewables by 2020. In the electricity market, this equates to about 35% of electricity. They cheat a little bit in that they include hydro in that, so quite a bit of that will come from large hydro. Most of the renewable portfolio standards in the U.S. do not allow hydro as a qualifying resource.

I will base most of my comments on the results of a piece of work from McKinsey, KEMA, Imperial College, London, Oxford Economics, and a number of others. The project is called

Roadmap 2050, put out by the European Climate Foundation. The presumption of the study is if an 80% reduction across the economy in greenhouse gases by 2050 is the objective, then what is required?

They began by looking at McKinsey estimates for the cost effectiveness of various abatement measures, what would be most economically efficient to get an 80% reduction in greenhouse gases in each sector. They found that regardless of how you get there, there's no way to do this without a power sector that is essentially zero carbon; between 90 and 100% de-carbonized. Further, that answer for the power sector would be the same for a 70% or 50% carbon reduction. Transport and sea transport are more expensive. Industry, buildings, waste, agriculture, and forestry are all very aggressive, as is a fully de-carbonized power sector.

When we talk about renewable we need to keep in mind what it is we're trying to accomplish, carbon reduction. However, if it's a 95% reduction in carbon, you cannot achieve that level without significant renewables. The only other possibility is that you build 200 to 300 new nuclear plants in the next 40 years. In that sense renewable portfolio standards or feed-in tariffs are part of a long term policy. In the short term they are essentially the phenomenon of early adopters in the consumer electronics industry. So in the short term the policy is not about reducing carbon, it's about commercializing technologies needed to meet the 2050 objectives for de-carbonization of the power sector. This is a different way of thinking about this question than we've heard from any of the previous speakers.

They constrained the study in two ways. First, they would not assume any fundamental breakthroughs in technology. Second, they assumed they could not import large amounts of solar from North Africa. Frankly, it's a good idea, but not from an energy security standpoint.

Second, they were in agreement with our previous speaker, no one should try to forecast or predict what exactly the energy mix is likely to be in 2050. There are two things we do know about 2050, politically. One is that the power sector has to be essentially zero carbon, and the second is for any of this to be politically viable, they have to be able to demonstrate with a high level of comfort that the power sector will be able to deliver the same level of reliability of service that it delivers today, if not better. So will it be de-carbonized, will it keep the lights on, and can we afford it?

The study looked at demand extensively, a lot of efficiency and also electrification of transport and heat. When you consider storage, the most cost effective way of providing storage to the system long term is to be able to choose when you charge electric vehicles. Similarly, to be able to choose when you run heat pumps is very cost effective. There's lots of heat pump systems in buildings, thermal storage systems, both heat storage for heating, and chillers associated with air conditioning. Very cost effective. So is energy conversion efficiency of modern electric heat pumps with coefficient performance of 4.0 or better with thermal storage. That is about 160% energy conversion efficiency, which is much better than the best biomass fired furnace.

They also included the retirement of the existing European fleet on schedule, so there are no early retirements built into this. The question then becomes, what do you fill that gap with? This is the retirement of the existing coal, nuclear, gas, and renewable fleet. There's still a lot of renewable because a lot of that is hydro.

They looked at three ways to de-carbonize the power sector. They're not projections, they're not forecasts, they're not recommendations. They simply said, how many different ways could you have a zero carbon power supply in 2050? They have be reliable, affordable, and virtually zero carbon. A scenario of 200 to 300 new nuclear plants in the next 40 years, and 300 to 400 gigawatts of coal and gas plants with carbon capture and storage was off the table. It was far too courageous in its assumptions.

They used three scenarios. 40% of electricity coming from renewable, 30% from nuclear, 30% from CCS [carbon capture & storage], then 60% from renewables, and 80% from renewables. They used only existing technologies with learning curves applied. Those learning curves were developed in deep dives with a combination of developers and providers of the various technologies as well as utilities that are using the output from those technologies. They arrived at about as close to a consensus as you can get. These are relatively conservative assumptions about learning for these technologies. They were applied across Europe using a relatively simple algorithm based on where the primary energy resources tend to be distributed, so lots of wind in the North Sea, lots of solar in the South, etc. It includes Norway and Switzerland. Norway has extensive hydro, and France balances its nuclear system on Swiss hydro.

At the 60 and 80% renewable scenarios, the intermittent supply is about 50 to 55% renewables, the balance made up of hydro, biomass, and geothermal. There is some solar thermal although with the European geographic constraint it is only 5% of supply because of land use constraints.

Base load operates as base load in each of these scenarios. Renewables operate to provide the balance of the system. They broke Europe up into nine regions. They modeled the operation of the system on 15 minute balancing with actual non spinning reserve and spinning reserve operations.

Gas turbines operate to balance the system during certain periods in the winter when wind and solar are both low. Germany has had similar problems with negative prices similar to Australia and Texas, most recently in 2008 where market prices went to minus 100 Euros per megawatt hour. So they want to eliminate that as well. I also want to emphasize that we're talking about all renewables here, not just wind.

The benefit from this approach is having a diverse mix of resources, with some demand response. There's tremendous benefit from a balance in your approach to the mix. Wind and solar are not correlated either on a daily basis or on a seasonable basis. The levelized cost of electricity for these solutions, over the period 2010 to 2050 isn't that much of a cost difference between new solutions and business as usual – approximately 15% more. The ranges reflect the confidence intervals and some uncertainty, especially in terms of carbon price and assumptions about learning rates on various renewables technologies. The learning rate on solar runs from five percent to 25% for instance.

How does all this happen, what's driving this seemingly magical solution? Well, it's transmission, wide area market operation – WAMO I like to call it, and it's active demand response. First, transmission is comparatively cheap. Even the transmission we're talking about here. Second, the combination of transmission solutions and the wide area market operation solutions drove curtailment among renewables from 15 to 20% down to one to two percent. They got rid of the negative prices problem, even with a much larger percentage of renewables. That is a huge cost benefit, a large increase in renewable effectiveness, and increased reliability. The negative price problems – in California, Texas, Germany, UK, Australia – they all come from operations in a constricted, smaller region. One of the questions they wanted to answer is what's the benefit of wide area market operations, and how much would it cost? The answer is it's dirt cheap, and the benefits are dramatic. It's not a cost issue, it's a political challenge.

The solution is focused on gigawatt miles of transmission and hundreds of millions of Euros in investment on backup and balancing costs. So when you try to solve this problem in Spain, they had as much as 45% of their electricity coming from wind at a single point in time. They have almost no interconnection with the rest of Europe, and they need about a megawatt of backup for every megawatt of intermittent supply that they have. When you increase the amount of interconnection between Spain and the rest of Europe to an optimum it is a huge change. The amount of backup generation required in Spain goes to about one megawatt of backup capacity for every 8-10 megawatts of intermittent renewable generation.

The optimum transmission was determined by adding it whenever it was cost-effective, but backing it off and replacing it with backup generation wherever that was more cost-effective. These scenarios include demand response at a relatively modest level by 2050.

Another surprising result is that demand is not well correlated across those nine regions on both a daily and a seasonal basis. If the transmission system can approach a merging of the demand curves of the nine regions, the amount of variability in the course of the day and over the course of the year is dramatically reduced. The ratio of peak to minimum generation goes from 1.35 to 1.2. That was a second significant, and unexpected benefit.

There is also a lack of correlation with resources across wide areas. So, for instance, the North Sea, is a highly correlated wind resource. They looked at hourly data from 2003-2008 in six widely dispersed wind sites across Europe, there's almost no correlation at all. That lack of correlation among renewable resources becomes much more dramatic when you approach it from a multi-source perspective, combining solar PV and wind, some solar thermal, geothermal, biomass. What happens is that if you have diverse sources, and diverse locations, and enough transmission, you lose the problems of negative price congestion and intermittency. The problems that occur in the UK or just Texas become much more easy and cheaper to solve when you look at it from a wide area market operation perspective.

The demand response assumptions worked as follows. They assumed that by 2050 if there are x number of gigawatt hours of demand in the course of a day, 20% of that can be moved within the day to where it was most valuable. At any given point in time you couldn't increase the load by more than 50%. Those were the constraints they imposed on demand response. In this scenario, the value of demand response isn't moving demand from the middle of the day for peak periods to off-peak periods. It may be, at certain points. But it's as valuable to be able to move demand from when there is not excess low-carbon, low-marginal-cost supply to where there is a point in the day where there is excess low-carbon, low-marginal-cost supplies to when there is low-carbon supplies.

So demand response works in terms of moving to times when cheap renewables are online. A small amount of demand response provides big benefits in terms of curtailment, the amount of backup generation, reliability, and the amount of low-carbon generation you can get onto the system; wind and solar and geothermal.

The transmission solution for the 60% scenario is a tripling of the interregional transmission capacity in Europe. There was a analogue proxy for how much intra-regional transmission would be required. The amount of investment reductions required to meet these objectives if they are done on a wide-area market basis as opposed to a member-state or region by region basis are 40% reduction at the 40% case, and 35% in the 60% and 80% case. There are significant dollar benefits for wide-area market solutions. Again, transmission and balancing, compared to literally everything else, is dirt-cheap.

The difference between business as usual and the de-carbonized scenarios is minimal. Transmission and wide-area market operations are a cheap solution to these problems.

The effect of delaying this kind of action is significant. Costs increase exponentially the longer a scenario like this is delayed. Carbon pricing is valuable for other reasons, but is essentially irrelevant to these solutions. Most of the capital investment that's going to be required to get this done is going to take place between now and 2025. During that time carbon prices will not be high enough to drive these capital investments. The variability in carbon price gets lost in the variability of future gas prices, construction costs, and the costs of capital. It's less that 20%. Variation in carbon price between €10 and €50 per ton is less that 20% of total costs when investors are looking at new generation. Carbon pricing chills both new investment and high carbon investment. However, even more important is the amount that things like gas price variability can chill investment.

The end point though is that this transmission and renewable rich solution provides a way forward with long term benefits, a de-carbonized world, and a less expensive, less energy intensive economy.

Speaker 1: The transmission measurements are in gigawatt miles? The backup and balancing costs are in the hundreds of millions of Euros?

Speaker 4: That's correct.

Speaker 1: What was the price per gigawatt miles for transmission?

Speaker 4: I'm unsure. Perhaps around €5,000 per megawatt mile but you should check the study to be sure. It was a weighted average of AC and HVAC, HVDC, above-ground and below-ground lines, it was about 27% HVDC, about 30% undergrounding.

Speaker 1: As a counterpoint, at a recent conference an EDF [Electricité de France] said all new transmission is going to be underground. 100%. Even in the countryside. So would that change things very much?

Speaker 4: Not dramatically. Different scenarios had more undergrounding, and they didn't assume any learning in the cost-effectiveness of underground HVDC.

Speaker 1: It's about 10 times more expensive than overhead, right?

Speaker 4: Well, it depends on how long it is. Today it's about 5 times more.

Speaker 1: So if it went from 30% underground to 100% underground?

Speaker 4: It's not going to go to 100%. EDF likes to say that. They also love to say that if you want new nuclear you've got to stop building renewables at 25% of penetration. That is also not true. They love to say that because it scares the bejeezus out of people.

Speaker 1: Fair enough.

Question: You seem to imply that the commercial viability of new carbon free generation is going drive savings, but don't you cut into the viability of those investments with the problems that Speaker 3 was discussing?

Speaker 4: They're only out of the money if you assume that the industry can still build coal plants. If we keep building coal plants, we shouldn't even bother having this conversation. Second, some of these technologies are out of the money today, but they're progressing at an incredible rate. Solar PV has had a 20% progress ratio on every doubling for the past 20 years. On-shore wind is probably starting to plateau, but it had about a 15% progress ratio every year since 1980. Off-shore wind is just beginning that process. Going back to the first point, the value of renewable support programs like RPS, is not in the short-term carbon reductions, it's in commercializing these technologies. We've looked at what the competitiveness of these technologies are by 2030, if you make a strong investment it will allow them to be in the money. They are not today, nor are they that effective in reducing carbon today but they will be fundamentally necessary to get to a zero-carbon power supply by 2050. The only way to do that without relying on far more nuclear and carbon capturing storage that we're ever going to build, is to find some way to commercialize some package of renewables technologies. This approach is significantly cheaper, and less risky than nuclear or CC&S.

Moderator: How can competitive markets address these emerging operational and innovation issues we've heard about?

Speaker 2: On the wind integration variability side, ancillary services markets can play a large role in making sure the most cost-effective resource of wind is providing the flexibility that the power system needs. There is an increase in the need for flexibility on the power system. Those markets have a critical role in providing the price signal.

Speaker 4: The biggest problem for competitive wholesale markets is the intensity of capital investment under any of the de-carbonization scenarios. This is especially the case for energy only markets, especially with the depression of marginal costs of production that prevails in increasingly de-carbonized power supplies. Energy markets cannot deliver. That level of capital investment is needed for 15-20 years. Forward capacity markets are not the only solution and other help will be needed. It's not clear what that help will or should be.

Question: Let's hypothesize the system at its worst 60 hours. The hottest of summer time for a peak load, when the wind just doesn't blow. If the base load disappears at the amount discussed earlier, what do we do to fill that gap? How does that system work then?

Speaker 1: Well, the good thing is companies sell both wind turbines and single cycles. We'll need more peaking capacity, and less base load capacity in the short term.

Speaker 4: No, actually that extreme is captured in the economics or the European road map.

Speaker 1: There's concerns there. The CAISO study, the assumptions that they make for the amount of regulation are incredibly naïve versions what is really going to be needed. They say three times the standard deviation of the wind. There is no model of the AGC system, there's no model of what it takes to satisfy CPS1 and CPS2 reliability. No one's done that, right?

Speaker 4: Actually, they did do it in Europe.

Speaker 1: The analogue of CPS1 and CPS2? OK, let me retract that. Not in North America has that been thought out. [Laughter]

Question: For example, the capacity factor for the summer peak at the Midwest ISO in their diverse footprint is 8%. The numbers we heard and say were as high as 40%, so that's why I had the question.

Speaker 4: The modeling calculated loss of load expectation of less than 3 hours per year.

Speaker 1: I know, the concern I have is they don't get anything at peak from the wind, right? If you're meeting demand growth with wind, you're going to need to also add gas turbines at the same time.

Question: Or storage.

Speaker 4: Or solar. I mean, renewables do not equal wind. There are other renewables. [Laughter]

Speaker 1: And solar thermal renewable particularly have greater potential for storage.

Question: And biomass.

Question: The concern I have is all the wind and solar and everything that's intermittent going away at the same time. This is a credible contingency. It doesn't happen very often, but it happens. Reliability rules say we have to build capacity to meet that credible contingency. I'm concerned that a serious contingency analysis has not been done. I don't think it's been done in the United States.

We have to address fraction of a second contingencies, like the loss of a large nuke plant. But also more gradual contingency problems that we might see with wind. The contingency concern is actually about 15 different kinds of problems. The contingency constraint is there 24 hours a day. There might be a period of time where this line goes down or the wind stops blowing and there's no wind for 25 minutes. The operating reserves are not going to solve that problem. They're there to deal with it over a short run. You're going to have to have something that you can bring on rapidly. 10 minutes, 15 minutes or something.

Speaker 4: There's no historically precedent across a wide enough geographical area for all of the wind going away at once.

Question: That's not true.

Speaker 4: It is true. Actually they've got the data in Europe to prove it. In the U.S. they're measuring it across Texas, they're not measuring it across the Eastern Interconnect.

Moderator: No, there are larger scale wind analyses for large parts of the U.S. There are days hours especially in the hot summer time where there's virtually no wind on-shore across broad areas.

Moderator: I think Speaker 4's point is that as you diversify, have larger areas, the amount that you're going to see falling off gets diminished. If you can get bigger areas -- bigger than the Eastern Interconnect, you drastically reduce that effect if you can make broader areas.

Speaker 4: The European models use gas turbines and storage, without assuming any fundamental technological breakthroughs. They are deployed to provide the level of reliability you are concerned about. They address the contingency of essentially no wind.

Speaker 1: We we should use fast-start generation. One complexity is there will be commitment represented in the day ahead but not in the real-time and this differs from California for example. So there's no way for those fast start generators to get committed by the operator except in an out-of-market action, which exacerbates the lack of energy storage.

One way to organize it is to say that we'll model those contingencies as a personal process, meaning over some relatively short interval, the system is prepared to live within a single contingency, there won't be two.

However, when you've got the die-off of older generation over a long time, the die-off and the events of a contingency could be coincident. The system would need additional reserves to cover the retirements that will be occurring. The problem is that if a peaker is there to cover retirements, it can't also be dedicated to covering wind intermittency. A problem in ERCOT currently is that operators don't do that.

Question: There's an operational issue that affects those counting on peaking generation for random events. The problem is that neither the transmission system, nor the gas pipeline system are designed for the massive input and new configuration of peakers. You have to have storage in many different ways here to solve this problem, both for transmission but gas supply as well.

Speaker 3: I completely agree with that. One solution is to have distillate oil storage associated with many of these peakers. Second, if heat is electrified, then that will free up a considerable amount of line on the pipeline system, and some storage, although storage is probably not optimally distributed right now to deal with this kind of a demand situation. The issue needs to be addressed dynamically.

Question: Speaker 3 talked about how the RPS actually hides the costs of climate change policy, and increases cost. However, speaker 4 noted if we're serious about getting to 80% reductions by 2050, we need to start investing now. These views seem to counter each other. Let's use the experience from the sulfur dioxide market as an example. The sulfur dioxide cap and trade program, prices weren't as expected, there was a lot of innovation. There was a valuable real option before taking compliance actions to see what the market would do, see how technologies would evolve in terms of their costs. There were incredible decreases in the cost of wet limestone. There were innovations in how to blend Powder River Basin coal and Appalachian coal, which no one thought was possible

I'm concerned about saying, it doesn't matter what the CO2 price is. Instead we should immediately start these investments. We could be picking technology losers that if we just sent the right price signals in a cap and trade program with a cap that is going to be 80% lower than it is today. Let innovation take place, let people make decisions in a decentralized manner to get there. Is there something that I'm missing?

Speaker 4: In Europe the cap is to get to a 20% reduction by 2020. That should drive up the carbon price between 50 and 80 Euros per ton by 2020. No one believes that's going to happen. There's a lot of leakage, there's a huge number of unsold credits sitting in Russia and the former Soviet Union countries that overhangs the market. Finally, many people believe that if push comes to shove and the politicians have to choose between holding the cap and letting the lights go out, then we can build coal plants.

Carbon markets are great for all sorts of things, but they don't drive positive early investment at the levels that we're talking about. In terms of picking winners, certainly it's important to have more of a balance in the way that renewables are encouraged. It shouldn't be all wind all the time. Off-shore wind today is more expensive than on-shore wind, but who's to say that's going to be the case 20 years from now. Technologies at scale need 5-10-15 years of experience operating it on the system. If we want innovation in low-carbon supply, that innovation needs to start happening on the system in real time.

Certainly some of the technologies in renewable support programs will fall by the wayside. We don't know. However, we know that the per-megawatt hour cost of PV solar has dropped by 20% with every doubling of experience over the past 15 years. Who knows whether that's going to go to 25% or go to 5% or plateau. You don't know until you push it.

They will make some mistakes. We make mistakes all the time in these things, we wrote off $250 billion worth of investment in gas-fired combined cycle plants between 2002 and 2005. Those decisions were made between 1998 and 2002 on the assumption that the new source review provision of the Clean Air Act was going to drive coal plants off the system. It didn't. If we want these technologies to be available 20 years from now and to be operational on the power system at scale, we need to start today.

Speaker 3: We are retreating from thinking about carbon markets and cap and trade as being in any way important to climate policy. We're substituting a set of centrally directed government mandates and, or subsidies directed at getting current technologies deployed. We will always be making mistakes, that's certainly something to take into account. They are always undesirable.

There is an issue of systemic risk in the private sector which generally tend to be smaller and lead to learning and moving ahead. When we look at government programs, the mistakes endure and the successes get cut off. The amount of out-of-the-money wind that's now spinning in Europe shows they are not that much better than we are at picking technologies.

Leaving aside the rent-seeking behavior of the US Congress and various proponents of technology, it comes down to our views on R&D. I am concerned about assumptions in the European study. There is absolutely no detectable learning curve that I can see in photovoltaic semiconductors that is going to get us where you are talking about.

Bill Nordhaus, a superb economist and clear thinker notes that progress rates are different from learning rates. I recommend his work. Progress rates say that there is a sequence of technologies that have been getting better, but if we look at what has happened in semiconductors across the board, it has not been something in which costs come down with cumulative production. It has been a process of new innovations which create and entirely new generation which then comes down a bit through learning. However, it's a process of R&D and continued innovation from which there is no reason to expect to continue. Deploying today's technology doesn't get us anywhere toward that goal of having a better future technology which will bring the costs down of doing these things.

So can either establish a stable long-term price expectation which I can only be done through a carbon tax. A cap and trade program is going to leave us uncertain about the carbon price forever, both because of the volatile market and the possibility of political reversals. So how do we get that stable carbon price put in place?

On alternative is we cobble together a set of standards and mandates. We generalize the experience when we model those mandates, but those mandates – rather through putting a price on carbon – multiplies the cost by a factor of three or four. We will use up the political tolerance for incurring costs, far before an 80% reduction in greenhouse gas emissions.

Moderator: We heard that the solution in Europe was very transmission heavy and cheap. How does it get built, and how does it get paid for? How is it approved?

Speaker 2: Transmission is far more effective than storage for moving energy and allowing energy to be put onto the grid. There's strong evidence that broad cost allocation is the central policy to get transmission built in places. Texas is getting it built. In areas of the country where you don't have the broad cost allocation, there isn't transmission getting built. It's a public good, there's open-access under our current transmission rules, so there's very little incentive for anybody, a private generator to invest in transmission if any of their competitors can come online.

Speaker 4: That's the toughest question. It's often said that Europe has a more unified grid, but that's actually not true when compared to U.S. regions and RTOs. The RTO type regional integrated structure is the beginning of a solution to that. The problem is the politics of how to socialize those costs.

It's not just transmission costs themselves that need to be socialized across winners and losers, but Missouri is going to see a much greater difference in cost relative to business as usual than New England will? How do you socialize that impact?

The RTO approach is the best template, especially for larger geographic areas, so long as they can work together with state-level politicians and environmental groups.

Europe is putting together a collaboration between transmission system operators and the environmental NGOs to promote the expansion of the transmission system where the expansion is explicitly designed on the basis of a de-carbonization of the power supply by 2050. That's proving to be very successful. It takes some of the natural constituency that opposes both the construction of the lines themselves and the socialization of the costs, and brings them inside the tent.

Speaker 2: Transmission is going to be around for 40, 50, 60 years. Benefits are impossible to predict. Further, almost everyone will receive a benefit somewhere along the way. The benefits of transmission greatly outweigh the costs. It's very difficult to find people who are net losers. All these issues demonstrate that socialized costs are the right way to go.

Speaker 1: Well, in ERCOT, to argue that the transmission lines for wind were anything other than transmission lines for wind is just sort of public utility commission double-speak. They're built because they want to access the wind. Socializing it as a starting point is not obvious to me as the right thing to do. It is comparatively cheap.

I'm concerned that we're going to find that the transmission ends up costing a huge amount of money. Estimates for ERCOT are $20 a megawatt hour. It's 25% of the cost of building the wind converted into dollars per megawatt hour. It's significant.

Socializing transmission cost also mean that we don't get incentives for new innovation in transmission. There's 101 new technologies that we might think about deploying, high-temperature conductors but it is not considered strongly in a socialized context. That's actually a big problem over the long term.

Question: In the U.S. context, the recent seventh-circuit decision says, show me the numbers. So far nobody's showed up with the numbers yet when they want to socialize it. When they do, the numbers they find don't make an adequate case for socialization. Will Congress change the rules?

Second, the only way we make this de-carbonization story work is with lots of demand response, lots of electric cars, which creates lots of electric storage, which will from time to time create very high LMPs, when the wind isn't blowing and there's not enough generation and the market's going to clear off the demand side. How does that get addressed?

Speaker 2: PJM and FERC are developing responses to the 7th Circuit decision. They have to provide justification for the existing cost allocation structure. They will be presenting arguments that demonstrate an improved response to the Court's concerns.

Question: They're going to be able to satisfy the socialization requirement, that is to say that the benefits are spread widely?

Speaker 2: I think so.

Speaker 4: Socialization needs to be seen as part of a carbon policy. Carbon policy needs to be complimented by other policies.

In terms of electric cars and the electrification of heat, the EU scenarios included conservative full electrification of heat in Europe and full electrification of small and medium-sized vehicles. They assumed that by 2050 vehicle charging and heat pump operation would be optimized by some combination of prices and/or smart grid control.

There was a lot of discussion about how to model the impact of electrification of heat and transport on occasional marginal demand. That work will be published in Energy Policy soon.

Speaker 3: The other huge technological uncertainty is that we don't know how to produce and electric vehicles that require a system that we don't have today. It's easy to come up with assumptions about new generations of biofuels for the transportation sector but a high penetration scenario seems optimistic. The dynamics of this are very complicated, especially in the U.S. I am skeptical about this level of penetration.

Speaker 2: Most of the studies I've seen show that you don't really need that much transmission for electric vehicles, because you can require that the charging be done at night through some type of mechanism.

Speaker 3: It's the energy, not the peaking that I'm worried about, for the electric vehicles.

Speaker 1: An important part of wind integration is being able to charge them when you've got excess wind.

Question: There are several different ways that we can achieve our de-carbonization goals. The cost associated with doing those things are acceptable in the sense that if this were the only option, I'd be willing to pay it. But there are a lot of other things that we might do and people are going to be trying to minimize the costs. One of the concerns is that we waste a lot of time screwing up going down the wrong path.

That leads to the question of how do you design the interventions, which I agree are necessary, because the markets aren't going to solve this by themselves. One way is by learning by doing. Let me give you an example of what I mean by this. The California solar initiative was a million rooftops in California by 2015. What they actually produced was a profile of credits and operating incentives that were driven by the learning model. They had the incentive structured so that if the learning rate story was correct, these incentives would drive a lot of solar production and learning. If their learning rate story was not correct, they wouldn't get much result, and that would be good, because the assumptions about learning were not actually correct.

If the program is successful it turns out incidentally that the scale was one quarter of the million rooftops. If we believe the learning argument, you only needed 250,000 rooftops. They're paying those incentives, I don't know whether it's going to work, I hope it works, I hope it produces lots of cheap solar. The key thing is they designed the policy structure so that it would work well if there assumptions were right, but at the same time if the learning assumptions were wrong, they weren't in fully. They didn't actually have to build a million rooftops.

Speaker 4: Introducing as much market discipline into this as possible is obviously a desirable thing. An RPS that says a million rooftops strikes me as kind of a mistake. The UK has modified their renewables obligations certificates program to introduce technology tiers where the level of support for technologies begins to abate or decline as the technologies become more mature. That's one way of introducing flexibility into a system that is based on letting the market work for a portfolio of technologies, and also of letting those portfolio technologies compete with each other for that segment of market.

The key is to create market-based regulatory interventions. A carbon pricing system is a market-based intervention. So, I agree creating a flexible incentive-based market system for renewables is the way to go. There's not a simple answer to your question but the general approach is correct.

The learning rates that the EU assumed reflected a consensus among utilities as well as PV manufacturers. They were relatively modest compared to what the PV manufacturers would liked us to have used. They also tested the robustness of the outcomes based on getting much less learning than was assumed in the base case. Those were reflect in the confidence intervals in the levelized cost of electricity.

The top of the confidence intervals in the de-carbonized scenarios assumed about half as much learning as was assumed in the base case, but the confidence intervals still overlaid each other relatively well. Nonetheless, trying to design good flexible market based systems like this will be complex.