

**Harvard Electricity Policy Group
Fortieth Plenary Session**

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RAPPORTEUR'S SUMMARY*

**Session One. Retail Competition: Why Does It Work In Some Places And Not In Others?
Comparing Experiences In Europe And North America.**

Roughly half the states in the U.S. have opened up their retail electric markets to full competition, but only a precious few have claimed significant success in terms of real benefits for customers other than large industrial users. Have retail price caps, price attractive "standard offers," and rate freezes, among the political compromises made to enact restructuring in several states, removed incentives for shopping? Are the potential savings to be had insufficient to motivate small consumers to change their behavior? Is it just the legacy of consumer lethargy (or perhaps brand loyalty) from the monopoly era that does not die easily? Are the costs of market entry for new suppliers too high, relations between incumbents and their unregulated affiliates inadequately regulated, and/or customer aggregation too complicated to accomplish given the limited possibilities of reward and that consumer trust for new suppliers is difficult to achieve?

At least four approaches have been used in North America, some with more success than others: full retail separation (e.g. Texas and Alberta), competitive generation supply (e.g. Ohio, New York, Pennsylvania), direct customer assignment (e.g. Georgia gas), and various types of segmented markets where competition is available in different ways to different customer classes (e.g. Oregon, New Jersey, Illinois). In some European markets, notably Scandinavia and England/Wales, however, significant consumer benefit has been claimed to have been derived from retail competition. What accounts for such different experiences? Why have the barriers to effective competition been overcome in some markets and not others?

Moderator.

Retail competition lets market players interact freely. The ability to switch suppliers should place direct and indirect pressures on things like service quality, product diversity, and price.

Because of these potential benefits, most countries in Europe, and about half in the United States, have introduced retail competition in some form. For instance, New Jersey passed an

Electric Discount Energy Competition Act in 1999 which allowed for retail competition. Residential and small business customers find few incentives to shop around because the perceived cost of becoming educated outweighs the potential cost savings.

In New Jersey, the few that were interested in shopping found little or no savings. They didn't shop because of artificially low retail price caps

*HEPG sessions are off the record. The Rapporteur's Summary captures the ideas of the session without identifying the speakers.

that expired in the summer of '03. Very few, really none, have shopped because of the BGS auction. The infamous New Jersey auction keeps wholesale prices down to almost the retail level. There are rationally ignorant non-shoppers in New Jersey, and in many states as well. Large commercial and industrial customers have benefited in terms of energy costs. New Jersey requires large users over 1,250 KW to go out at spot prices in the PJM wholesale market. 64 percent of those customers are shopping, about 1,200 accounts in the state. They have switched to competitive suppliers. That's about 84 percent of that load.

For residential and small commercials, there's really no shopping going on. The New Jersey Board formed the Basic Generation Service (BGS) Auction four years ago to try to get them the benefits of wholesale rates. This created new market participants, the wholesale bidder. The auction allows prices to be set effectively, and the risk taken by market actors. Generally, competition has tempered larger price increases and commodity prices, at least until the occurrences this year. Over the last five years, up until the past year, the price of natural gas had gone up 300 percent -- over 300 percent in five years, and 41 percent over two years. Yet in that two-year time frame, the New Jersey residential bill went up less than three percent in that same two-year period.

Efficiency gains have also been seen in a number of European countries. This is a result of robust generation markets, privatization of national utilities, and a formerly nationalized workforce that was reduced in size. According to the UK government, the average price in real term dollars between '97 and 2002 fell by about 10 percent for gas, and 19 percent for electricity in Britain. For industrial users, it fell more than that during that time frame. I'm interested in seeing a comparison of what would have happened without retail competition. Recently, prices are obviously not falling any more all over the world.

In some countries and the United States, the prices really haven't decreased much, and

reform has clearly stalled in this country. The questions are: what accounts for these different experiences; why have the barriers to effective competition been overcome in some markets and not in others?

Speaker One.

I will talk about retail competition in the Scandinavian market. The entire market was opened for competition. There was no phasing in of smaller consumers. The market was open to the big and small ones right away.

A lot of new entrants, or at least quite a few of them, have switched or renegotiated their contracts. All the Nordic markets have been firmly involved in electricity market reform. Norway started in '91; Sweden in '96; Finland, '97, and Denmark, 2002. They are all joined in the wholesale market.

This reform includes vertical separation. In Sweden, it's been separated so that transmission companies can't be working within the same legal entities as the rest of the companies. They must be switched over, not just by the accounting, but as legally separate entities.

The establishment of independent Transmission System Operators (TSO) spurred clear regulations for third-party access to the market. All consumers are allowed access to suppliers. There's been no regulation on the electricity price to end users. There is also a jointly-owned power exchange. The wholesale market represents the whole geographic area of these countries. Everyone can buy power at the same price, more or less, in this joint market.

The market has transformed over the years. It started as a monopoly; vertically integrated companies trying to function in this market. Other kinds of companies, historically, have grown into this market. Mixed ownership and prices occurred in many of them: big state companies, small private firms, and large private firms all over the region. After deregulation in '96, when Sweden came and joined Norway,

market shares were the focus for the incumbent because prices were dropping.

The production chain has a lot of hydro power in the Nordic region. There is 100 percent hydro power in Norway. Fifty percent of the production in Sweden and 25 percent in Finland.

The Nordic region is prone to rain; a lot. The years '97 through '99 were three extremely wet years. This affected the wholesale price a great deal. Established companies in the market were starting to compete strongly to get market share. Some small municipally-owned companies all of a sudden thought that they were going to rule the whole country. They started to market themselves as a national suppliers, and worked hard to get more customers with price competition. And many of them got more customers.

New entrants came in part because of a requirement for meter change in the Swedish market. Customers had to buy and pay for a new meter, which is okay if you are a big industry. If you are a small consumer with a house or apartment, that is a large transaction cost. It reduces the possibility of gaining money by switching suppliers. This requirement ended in November of '99. This made a big difference, and intensified the competitiveness among companies. Ones that were already in the market tried to figure out new products, and competitive activity increased. Oil and gas companies came in; foreign actors too. There was a lot of confidence in the markets.

But then it stopped raining, more or less. Probably temporarily -- that's my projection -- but at least for a couple of winters, it didn't rain or snow as much as it usually does. Of course, when you have a lot of hydro power in the system and all of the sudden you don't get any hydro from above, then prices have to go up.

Wholesale prices got really volatile, with higher prices. We didn't have any regulation on the prices. Not even for old contracts, standard form contracts, or normal price contracts (in which customers that had done nothing received that

price). The incumbents could increase prices with a two-week notification, following an increase in price in the wholesale market. This created turbulence for new entrants. They were faced with the same increase in wholesale prices, since there is a joint wholesale market for the whole region.

Companies that had been competing for market share realized that you have to make money as well. Companies began disappearing and they had to consider their risk management situation. A lot of consolidation occurred. Some companies went bankrupt and there were a lot of mergers, forced mergers for some companies almost going bankrupt, and some just not making enough money to survive in the long term. This is still going on, even though it's started to rain a little bit and there is a normalization of the hydro reservoirs. But it's still not back to normal.

Nonetheless, consumers are switching. They expect to earn some money doing this. After the requirement for new meters was removed in November '99, they adopted a system with a general load profile used for all the customers. While this is a simplification, it removes the new meter transaction cost.

This happened in November '99 and it takes some time for people to react. After December '99, you see an increase in switchers. Around 60 percent of the total number of customers have changed suppliers or renegotiated with their present suppliers. This is a big jump, especially those that renegotiated with their old suppliers. There are also a lot of changes in suppliers.

Since April 2004, statistics report on how many new contracts are written, and the annual volume of these contracts. There is a fairly steady flow of contracts. This year it's about 10 percent of the annual overturn that's being renegotiated each month, except in January. There are more then because many industries have contracts that have to be renewed at New Year's. There is another little upturn in May. That is due to the fact that we have a hydro system. The media places a lot of attention on

the spring flow and the fact that electricity prices are usually lower in the beginning of the summer. That's when you should renegotiate electricity contracts. And people are doing that. It shows customers trying to be rational. Industrial users, large users, are key movers of course. However, more than 60 percent of single-family households have changed supplier.

Since there is fairly inexpensive electricity supply within the region, there's a lot of electric heating in households. A typical house with electric heating consumes about 20,000 kilowatt hours per year. A typical UK household uses 3,600 kilowatt hours per year. Customers will search a few more hours for a better deal if they have this higher consumption to address.

People also need information to make an intelligent decision regarding their electricity bills. This is a commodity that households have not been shopping around for. Usually, you just pay your bill. All of a sudden, you have a new thing to learn. In the Nordic markets, the bills have not been easy to understand. There's been criticism that the bills hide what's going on. What is the transmission part? What is the energy part? What is the part of the bill that's competitive?

There are now standardized pages on the Internet where the user can input their annual volume, the price deals they're receiving, and deduce the fixed cost. The customer can see which of the deals is the best one. The bills are also getting better. They are becoming standardized, and customers can clearly see the competitive portion. Consumers are starting to realize that it's not so difficult to shop around for electricity any more. As I said, there's been no regulation on the price of the energy. There is no risk of having the regulation disturbed or canceling the expected gains from a new deal.

There's been a turnaround in the number of companies also. There were 221 distributors in '96; in 2004, they were down to 97. Many companies were targeting the whole nation. There were only 10 in '96 and up to 50 in 2000,

when a lot of them were aiming for a larger market share. Currently, it's down to around 20.

In Sweden, even though there are almost 100 distributors, or retail electricity sales companies, there are three that serve 70 percent of the market and have 90 percent of total production. It's a more concentrated market than the Norwegian one, where the largest distributor has only 30 percent of share. They are not selling all their power to the smaller retailers; they're selling it primarily to industry.

The different levels of concentration in the Norwegian and Swedish markets are important. The "normal" [default] contracts (the contracts that are for customers that are left in the market and have not done anything) in Norway are much lower than Sweden at the same time of year. This is persistent over time. Some question whether this is due to the higher level of concentration in Sweden. There are also differences in one-year fixed contracts but they are quite close at this time.

The low prices in the early years was due to the wet years, or perhaps due to the deregulation. Nonetheless, there was a drop in prices that consumers were very happy with. Since then we've seen an increase in prices. As an aside, when the prices dropped, taxes increased. The consumers didn't really get much of this benefit. It went into the authorities pockets, but that's a separate issue.

To conclude, switching costs do matter. The elimination of the metering requirement was really important. Now there are no costs to switch. You don't have to fork out any money to get a new deal for electricity in the Nordic market.

Furthermore, the information has improved a great deal. People understand how to switch. It's easy to switch to a new supplier, or renegotiate with the old one. There's usually a substantial difference between the "normal" price and a one-year contract. You can lower your cost by calling your old supplier and going on contract. A lot of people have done that. The vertical

separation has clarified the competitive and monopolistic part of the market. You have the threat of new entrants. New entrants have been entering, and some have been leaving again, as in a usual market.

Clarifying Question: You said the prices actually came back up to where they were in pre-deregulation times. But if you went back 10 years, 15 years, did the rates vary tremendously year to year, even in a regulated world?

Response: No. Then you had more of an average pricing philosophy that evened out. Of course, you had dry years in those days, as well. But those swings were more taken by the utilities. Now, it's coming out to the markets correctly. When you have high or low prices on the wholesale markets, it extends all the way to the retail customers.

Speaker Two.

I look at the UK experience through a North American lens. I hope to identify those features of the UK market which are most striking to a North American audience. I've organized my remarks around five questions. First, what is the measure of success, and particularly, what was the measure of success in the UK retail market? Second, what does the UK retail electricity market look like today? Third, how did we get there? What was the route to where we find ourselves today? Fourth, what were the key factors that facilitated competition in the UK market? And finally, I'd like to reflect on challenges that the UK retail market faces going forward. I think there are issues on the horizon in the UK that may threaten or compromise the continued successful operation of that market.

Let's consider the measure of success. The domestic UK electricity market opened to competition in stages through to the middle of 1999. The measure of success is really found in the decision which the regulator, the Office of Gas and Electricity Markets [OFGEM], made three years later to lift controls on the prices that the incumbent suppliers could charge within

their service territories. OFGEM's decision to do that was based on the regulator's assessment that the market was sufficiently competitive.

OFGEM cited several factors. First, retail domestic consumers now had a choice of supplier. There were originally 14 regional providers in the UK. They were now in a position to compete outside their historic service territories in the areas of the other regional electricity providers. Significantly, there was also entry into the retail electricity by British Gas. British Gas was the former monopoly gas provider in the UK. It had unbundled several years earlier when the gas market had been liberalized. They captured between one-fifth and a quarter of the domestic electricity market very quickly. Currently they are the largest provider in that market by a point or two.

The second factor that OFGEM took into account was the amount of switching within the market. In the early days, switching was occurring in the neighborhood of 100,000 customers per month. The majority of customers were switching as a consequence of telesales and doorstep face-to-face selling. Price comparison websites were in their infancy in those days. They are now a more important component of the market.

In the early years, the market share of the incumbent retail electricity providers in their historic service territories declined to about 67 percent by December 2001. This was just over two years after the opening of competition. That's declined further, and on average, the incumbents enjoy a market share in their historic service territories of about 55-56 percent.

The third point that OFGEM considered in deciding to lift price controls was the significant savings that customers could realize by switching. It's important to reflect on why customers were able to realize those savings. Incumbent electricity providers had entered into a portfolio of long-term supply contracts, often with American-owned IPPs who had entered the UK market in the late '90s. The prices in those contracts were largely above the prices new

entrants were able to acquire at the market opening. Luckily, the market opened at a time when power prices were declining. In 2002, OFGEM calculated that headroom was between three to thirteen percent, depending upon the region and the type of product. Consumers could realize between five to fourteen percent savings on average.

Another criteria for OFGEM was their satisfaction that the benefits of competition were being realized by all sectors of the market. We'll return to that issue later. The last factor they considered was whether a clear regulatory framework existed to provide adequate consumer protection. OFGEM has jurisdiction over issues such as mis-selling and performance standards. They enjoy concurrent jurisdiction with the Office of Fair Trading under the Competition Act. Increasingly, you see the UK energy regulator relying on competition law to monitor and oversee the UK energy market.

I want to give you a picture of what the UK electricity market looks like today. The first feature in the current UK market that I want to highlight is the separation of the retail supply and distribution functions. This is a common feature with the markets in Scandinavia. In the UK the distributors have exited the merchant function. In some instances, the distribution and the retail supply company in that area remain under common ownership, but the relationship between them is governed by a strict code of conduct. That separation was a critical factor because companies could be confident that they could enter the retail market and compete on a level playing field with incumbent providers.

The other feature that's worth highlighting is the considerable consolidation we've seen in the retail supply sector since market opening. Currently there are really six key suppliers. There is a considerable degree of vertical integration between the retail supply and the generation markets. There are niche players within the market, but none of them has a material presence, or customers in excess of 150,000.

There is a broad range and type of products that are offered in the retail market. Each supplier offers a standard tariff that is their core offering. Traditionally, that price would vary perhaps once a year. In the current environment, where wholesale prices are more volatile, they change more frequently, perhaps twice a year on average. We may be moving into an environment where prices change more frequently than that. In addition to the standard tariff product, most of the big six providers in the market offer an array of fixed price and capped products which may have a term of two or three years. One company just launched a product with a term of four and a half years, the longest so far. The market is increasingly a dual fuel market where customers buy both their gas and their electricity from the same provider.

Another important feature is the governance of the market by multilateral industry codes and agreements. These govern matters such as balancing, switching, settlements, and the terms of access to the distribution system. Although market participants are in a position where they have to interface with as many as 14 different distribution companies, they're doing so under a standard set of rules and business practices. This market of approximately 26 million retail customers is governed by one set of business rules and processes.

The wholesale market is now governed by BETTA, the British Electricity Trading and Transmission Arrangements. This structure encourages suppliers to cover their downstream obligations in the forward market. It's a simple energy-only market. It doesn't impose on retail providers anything akin to an ICAP obligation. There are, nonetheless, two material types of obligations imposed on retail providers. The first is the renewable obligation. All retail providers are now required to source an increasing proportion of supply from renewable resources. That will go up to 10 percent by 2010. The government is hoping to increase it to 20 percent at some point. Perhaps a more unique obligation, they are also subject to an energy efficiency obligation. All licensed providers with an excess of 50,000 customers must invest in a menu of

energy efficiency initiatives. These will yield savings of approximately 130 terawatt hours in the aggregate between 2005 and 2008.

The market is governed by a sophisticated regulator, OFGEM. Alongside OFGEM, you have Energy Watch. Energy Watch is a consumer advocate; it acts as ombudsman, deals with complaints, and can be a goad to both regulator and market participants. There can be considerable tension between the regulator and Energy Watch with respect to governance of the market.

Competition is continuing to work in the UK market. There is a high degree of switching. A lot of that switching is currently away from the largest market supplier. As a consequence of increasing wholesale prices, they increased gas and electricity prices 14.2 percent in September. They were the third supplier to do so. Some companies have announced new products designed to mitigate the impact of those price increases. One was the 4.5 year fixed price contract discussed earlier. Competitors quickly responded to the price increase and the new products. Without question, price is the primary feature driving switching and choice of suppliers in the UK.

The route to competition in the UK was a long-term exercise, beginning with the publication of the White Paper in 1998. It's important to recognize what was going on in the wholesale market alongside the changes in the retail market. During that period, there was significant divestiture by the two new, large generators, National Power and PowerGen. There was considerable investment in gas-fired generation by IPPs, many of them American-owned at that time, supported by long-term contracts with the incumbent generators. In the late '90s, the wholesale market was preparing for the opening of the retail market. In retrospect, the regulator did not play a strong enough role in that process. They could have had a stronger leadership role in the mid to late '90s and we may not have seen the difficulties that were experienced.

These are the factors that account for the success of the market. The first is the high degree of political and regulatory commitment to the introduction of competition. Second, the separation of supply and distribution, and the establishment of a level playing field. Third, the market opened at a time when we saw declining wholesale prices. This, coupled with the fact that incumbents were burdened with the portfolio of legacy contracts enabled new entrants to undercut them. Fourth, the value to all participants in a uniform set of business rules and processes governing such a large market.

It's worthwhile to highlight two other factors. First, every supplier in the UK has an obligation to offer terms to all customers. This ensures that all sectors of the market are adequately served by competition. These institutions address issues such as fuel poverty and vulnerable customers that are critical to the ongoing credibility of competitive markets.

The last point is the mandated access to key features of the incumbent infrastructure. A high proportion of the UK market was actually on prepayment meters. Those prepayment meters were served through an established retail network where people take prepayment cards and have them credited. It's a significant portion of the market. Unless new entrants could get easy access, it would have been foreclosed from the market for a considerable period of time. The regulator probably would have retained price controls on that sector of the market for a considerably longer period.

Clarifying Question: Are there unique problems that you faced with vulnerable customers in this experiment?

Response: The government and the regulator have left the issue of how to address fuel poverty and vulnerable customers to suppliers. They have encouraged suppliers to offer social tariffs, the assumption being that these will be offered largely to people who are vulnerable, defined as the elderly or people who are on social assistance of some type. These tariffs will be discounted in some way.

That works plausibly in a regime of reasonably stable or declining wholesale prices. It's more difficult to leave that obligation on suppliers in a market where prices are increasing. It's a concern with recent price increases. Some prices increased 14.2 percent recently, and that's significant for people on social assistance. There is currently a social tariff that largely protects vulnerable customers against that price increase over the next winter. Companies can erode their own margins to provide this assistance, but soon you're asking other customers to subsidize vulnerable customers. The current regime of social tariffs is not working. There's a need to think of other ways of addressing the needs of vulnerable customers in the fuel pool. My own preference would be to reestablish some sort of social benefit fund because it's clear that the government is not going to do it by way of taxation. Money could be collected through the distribution of transmission tariffs, and used to establish a fund for vulnerable customers.

Speaker Three.

New York and New Jersey are restructuring states that have pursued a strategy of wholesale competition. In both states, all customers are empowered to choose an alternative supplier. In New Jersey, commercial industrial retail competition is encouraged while the utility remains primarily as energy supply provider for the mass market. In New York, both mass market and commercial industrial retail access was encouraged, while the utility remained as provider of last resort.

In New Jersey there is a competitive environment, with the basic generation service (BGS) regime increasing migration of commercial industrial customers. The large ones get a half cent addition to their real-time pricing if they stay with the utility. It's a significant motivation to migrate to retail access. The BGS approach in New Jersey for the mass market certainly mitigates price volatility, and its associated price signal. New York took a different approach. It sought to reduce the PUC oversight over areas of utility activity in a truly

competitive environment, and to migrate customers to third-party providers. Customers were empowered to choose providers, and utilities were encouraged to develop programs to encourage migration. The result was growing migration.

Some utilities have a program where they provide billing for an energy service company (ESCO). Their bill goes in the utility's bill every month. The utility buys the receivable from the ESCO. There are also special introductory programs. In the first two months of service with an ESCO, customers can be guaranteed a 7 percent reduction from the utility energy supply portion of the bill. Customer understanding is important because restructuring is so confusing, but ESCO participation continues to grow.

Most thought it would be a long transition to competition, and many continue to think so. We're closer to the beginning of the transition to competition than the end. In that vein, a key element in a retail market is customer understanding. It's difficult to penetrate customer consciousness, and to get a firm understanding on their part, so it makes sense to go slow.

In New York, the incumbent utility does not go out and procure a 100% three-year supply. There is volatility month to month in the bills. That gives a price signal to customers that may want to choose. It might be better to provide that price signal and to accept some volatility in the bills during unstable times when customers might want to see stability in their prices. Customers can migrate to an energy supply company that has a fixed pricing alternative.

We have a fragile transition. That fragility can doom a program to failure or guarantee its success. If you have a lot of rainfall or oil price fights that provide low prices in those first years, you're better off having a long-term view, and deciding what way is best in terms of overall economic efficiency.

There's a strong argument for retail access as an appropriate transition to competition. The

wholesale energy market is competitive. There's no reason why, either with strict state supervision or relaxed supervision, an incumbent utility ought to be the sole purchaser of that energy supply.

It's difficult for energy marketers to make an economic case right now because some utilities are efficient in acquiring energy supply, both under the BGS and the New York format. They pass those efficiencies to the customer at no profit. The energy supply company is competing against an entity that is good at purchasing, and is not in that as profit center. However, the utility is more a plain vanilla provider. The ESCO has the ability to provide different services. Green power is a promising area. Finally, public policy has an important role in the evolution of retail competition.

Speaker Four.

It's worth thinking about a long-term time frame if we're going to attempt to do this kind of transition successfully. Maine generally has been successful in launching a form of retail competition. It's a hybrid form that resembles some elements of the Nordic and British models.

There is 90 percent participation in the industrial portion of the retail market in Maine. That's been fairly constant. For the residential portion, virtually all of it is conducted under a standard offer bid auction process, similar to New Jersey's, that has also been relatively successful. It is a kind of bifurcated system. Energy efficiency is now operated by a division of the Maine PUC. It's no longer in a conflicted position of being part of the utilities' operations, with the simultaneous responsibility to sell more kilowatt hours, and also sell fewer. It's adequately funded. Finally, there is aggregation underway in Maine. However, Maine is a tiny state with a population of 1.2 million.

Let's examine the pattern of migration for the three utilities in the state. The largest, Central Maine Power, has high participation levels in the market by industrial customers who shop for

their own power. Commercial customers, it's around 35 percent; for residential customers, it's essentially less than one percent. Maine Public Service supplies northern Maine and it's a smaller utility. Again, it has high participation levels, above 90 percent for industrial. Its residential market has as much as 32 percent participation. That's because the competitive provider happened to be an affiliate of the local utility and had a home court advantage. People wanted to buy from their neighbor, rather than the standard offer provider from Wisconsin. That affiliated arrangement has terminated, though. The third major investor-owned utility, Bangor Hydro, shows a similar pattern. It's more volatile due to people dipping in and out of the standard offer, depending on cost advantages for industrial and commercial customers.

Renewable power generation is more than a thousand megawatts, and represents a major part of the system mix for the State of Maine. Only a few of those units still commit outputs under PURPA type contracts. Mostly they're either in bilateral arrangements or they bid into the ISO New England market. There are 2,000 customers that pay a premium for buying 100 percent renewable power from a retail provider.

Standard costs are declining fairly significantly. As you get to 2013, for Central Maine Power, they level out at a level below \$40 million. There are some opportunities now to reduce rates, or at least absorb some of the increase on the supply side because of this decline in standard cost. In real terms, residential electricity in Maine is close to what it was six years ago. That is a comparative success. In the case of Central Maine Power, it's increased 6.7 percent nominally over six years. Over the same period, gasoline prices rose significantly more, as did heating oil prices.

The key element is the same as the UK and Nordic markets; separation of the supply from the distribution function. There was a legal obligation for the T&D utilities to exit the supply function. Currently, there are no affiliates of any T&D utility that sell supply in Maine. Since they have no interest in that market, they have been perceived as honest brokers who can

facilitate switches for competitive buyers without bias to the incumbent.

Standard offer contracts are bid out, similar to other Northeast states, on a three-year basis using a ladder of contracts in which one-third of the contract expires over one year. This is for residential customers. Industrial and commercial customers typically have six-month contracts that closely track the spot price. Maine benefits from having lower wholesale zonal costs compared with the rest of New England.

For a variety of reasons, the system in Maine now enjoys general support. The Legislature was thoughtful when they put this process together. Ten years ago, there was an extensive two year consultative process with stakeholders. This included a coalition of industrial, environmental, low income, elderly, and business customers. They were active in the process of drafting the legislation. There is no interference by incumbents in the transactions concerning the supply market. The PUC in Maine has been careful to implement the standard offer auction process without bias. It enjoys confidence now, with plenty of bidders each time there's a standard offer auction. The renewable portfolio requirement in Maine is 30 percent. There's also a net metering requirement. In general, there is strong support for indigenous generation in the state. That's another reason why this program enjoys general confidence in the state, even though prices increased two cents last March for residential customers.

The consumer-owned utilities in the state have been able to maintain a significant price advantage in terms of reduced total costs. The four consumer-owned utilities operate with total cost below nine cents, including their standard offer and their distribution, whereas the investor-owned utilities typically have higher costs. The highest costs of all relate to the service of islands off the coast of Maine, and that's very expensive power.

Two caveats. One, Maine is at the mercy of market forces in the wholesale market. One hurricane or two can make that quite obvious in

terms of effects on natural gas prices, and on the standard offer once it's renegotiated. Second, there is no obligation to supply. If power generators aren't built, then there's no obvious fix for that. Right now Maine has adequate reserves in each of its control areas, but there's no guarantee that that will continue. I speak as an opponent of ISO New England's LICAP proposal, but I do support forms of resource adequacy that create a price signal for capacity.

Maine never understood its effort as one of promoting competition for the sake of competition. The attempt was to create a competitive retail market to better manage risks of failed generation projects, and to better manage prices. We have never set up headroom in the standard offer program to create an opportunity for competitors to get market share. There has been a general consensus that electricity is a necessity of life. Affordability is a key aspect of Maine's effort. For that reason, the standard offer has not differentiated into a default market or a credit unworthy market. It's the biggest possible pool of people who do not want to choose, and the hope is that will generate the highest degree of affordability.

Here are some key factors: non-interference by government; an attempt to have a fair system; encouraging renewable resources; and placing provider of last resort service above economic efficiency, even if there is a rationale for subdividing. We need to figure out ways of approaching electricity supply issues in terms of a universal service approach. The primary goal of our policies should be to ensure that all consumers have access to reliable, reasonably-priced service. If competitors can provide that, great, but that shouldn't substitute for the fundamental obligation of ensuring that supply is available.

Clarifying Question: The consumer-owned utilities have a lower price than investor-owned. Are customers throughout the state free to choose the consumer-owned utilities, or it's not that flexible?

Response: You're captured by your geography. If you're in the service territory of the

consumer-owned utility, then you benefit from a lower total price, and if not, not.

Discussion.

Question: There was a lot of discussion early on about whether we need to go to retail. Maybe the customers can get all the benefits if there is only a vibrant wholesale market, and load-serving entities buy from that wholesale market. Is that, in essence where Maine has ended up? Maybe that model was the appropriate model, or were there significant tangible benefits from going to retail beyond the wholesale market?

Response: If you asked me if I could do it all over again, would I adopt that model? I probably would say yes. If you're asking me, has Maine ended up in a place that's identical to or functionally equivalent to that model? I guess I'd say no.

There are large entities in Maine that are extremely interested in shopping for their own power, and aren't interested in accepting the supply decisions of vertically integrated investor-owned utilities. They want to substitute their judgment for the judgment of the utility planners and power acquisition people. If we only had a wholesale type form of competition without any retail competition, there would be no retail choice for those large industrial customers, and they would regret that. In fact, they would probably try and secure that.

Question: In the description of the Nordic model, countrywide initiatives with a Nord Pool jointly-owned PX created the landscape for the process. In the UK, somewhat similarly, there were OFGEM uniform rules and market design laid out evenly across the region. In the U.S. we have a bifurcated state/federal jurisdictional construct, and different ISOs that may or may not lend additional complexity. How can we get through the hurdles in our more complex structure, to gain the success of your models?

Response: When you look some states that have pursued an agenda of retail competition, you

don't have that uniformity, even within a state. You often don't have uniformity of rules. The business processes, the rules of engagement with the distributor, often vary on a utility by utility basis. This can result in a number of small, quite unique utility-specific models. To the extent that you can adopt uniform business rules and practices across a broader region, the easier it is for a new entrant to enter that market. Differences in rules are a serious barrier.

Response: In the Nordic market prior to deregulation, there was cooperation among the countries to optimize the system. They built up routines for trading over the borders. There have been interactions between the countries in order to create cooperation around these issues. I don't know enough about the different states to say where that could be applied better. The more cooperation that you could have around issues like that, the easier it is to get into the next step.

Regulators were worried about having dominating companies that would run the prices in the markets. They realized that if they created a larger market at the outset, that would dilute dominating actors. That was one driving force for having the whole region as one market at the outset, to increase competitiveness.

Question: How do we get from our current disjointed puzzle where the pieces don't quite fit to something that allows the sort of success they've had to follow?

Comment: Europe phased in the process slowly. The U.S. did competition all at once. Did the UK do rate caps?

Response: Up until 2002. The market opened in 1998-1999. For the next three years, the incumbent retail providers operated under price constraints or restraints that had two objectives: to ensure there was no exploitation of captive customers, but also to ensure that, implicitly, that there was sufficient headroom in their prices to attract new entry. A unique issue may have been luck in the market structure that we inherited. The success in our regime has been in attracting new entry into the market. These

players were not really new entrants. They were the old incumbent supply companies who were had systems, were well-financed, and in a position to compete outside their traditional service territories.

Question: In the UK they have one person who's in charge of this. We have many, many states. Some are political appointees; some are elected. It's kind of cumbersome. How much difference is accounted for by that infrastructure scheme and the single government entity?

Response: From 1988 until 2002, I don't think you can underestimate the importance of a strong political and regulatory commitment. Interestingly, it was a commitment that survived the change in government. The Labor government today is as committed to competition as Margaret Thatcher's. They've overlaid new concerns about environmental and social policy, but their commitment to competition is just as strong. One can't underestimate the importance of strong, charismatic leaders like Steven Littlechild, and Callum McCarthy, who were able to drive these issues forward.

Comment: In New Jersey, there was a change in administration from Republican to Democrat. This generated pressure to undo it and put the Genie back in the bottle.

Question: There have been some cases where utilities have states coming to them in the post-Katrina aftermath, and even pre-Katrina to a degree, and saying they may have to invoke some form of regulatory force majeure. Political realities being what they are today, regulators are requesting that utilities suspend penalties for customers who go back on the standard offer. If a utility has standard offer and current flow-through, regulators may ask them to lag flow-through for a year or two, because the customers will not be able to deal with a gas market that this morning was selling north of \$13.

Has Europe dealt with this kind of volatility in a competitive retail market, and did the market basically continue to function, or was there

interim intervention to soften the blow? In the U.S., if regulators intervene, what message does that send, and what is the long-term implication?

Response: The Nordic market experienced extreme wholesale price increases in the winter of 2002 and 2003. This was due to a dry year. There were cold winter days right after Christmas, and there is a lot of electric heating. The prices went up at least two or three hundred percent from the normal level for just a few days on the spot market. A lot of politicians starting asking what's going on. The people in charge of the wholesale markets explained that this is a capacity pricing situation; the market is close to the capacity limits and the supply curve is very steep and you get high prices. This is supposed to feed back into the system to decrease demand. The politicians listened. In Norway some of the aluminum industry left their people on a longer Christmas holiday. They sold their electricity back to the market because they had fixed-price contracts that included sell-back. They earned much more money just by closing down the plants for a few weeks. Very soon, the price came back down again. The market managed to handle this extreme situation.

Response: In the UK, there has been no intervention of the type to which you refer, and I don't anticipate that there would be, certainly under the current government or regulator. However, among suppliers there's a high level of concern and sensitivity about consumer response to high prices.

Some suppliers have made the explicit decision not to price through to consumers the entire price increase that might have been warranted by an increase in wholesale prices. They have decided to reduce their margins and operating costs instead. This began in 2003-2004, when significant increases in gas prices began in the UK. There was pressure from some customers on the government and regulator to find a solution. A viewpoint emerged that high prices reflected something wrong with the market. The regulator undertook an extensive inquiry and concluded that there was nothing fundamentally wrong with the operation of the market. Many of

the UK issues, particularly with gas prices, are tied to the lack of liberalization in European markets.

Response: Intervening in contract arrangements as a first option could cause a lack of confidence over whether future contracts would be fulfilled. However, vulnerable customers must be protected by long-term supply arrangements. We have failed to transfer risk to the successful bidder of a standard offer arrangement if we concede that any time there is a big bump, it's time to renegotiate. We have to stick with the deal we cut. Demand response is the appropriate reaction to a price break. If government can promote more efficient use of gas, electricity, that certainly facilitates the right market signal. This is the time for effective, focused, well-financed efforts to promote energy efficiency.

Response: In the spring and summer of 2001, New York had price spikes similar to California. There were legislative hearings but they maintained calm. The utility prices continued to reflect the market, and the crisis passed. There's a breaking point where what's a crisis and what's not is really the question. The more you can let a crisis pass without undoing a lot of sound regulation, the better off you are.

Response: OFGEM and the government are very conscious of the hazard of intervening in markets in the UK. The approach to security of supply depends heavily on investment by market participants. However, significant investment in infrastructure is needed over the next few years. It's now a net importer of gas, as opposed to an exporter. Three or four years from now there's going to be significant need for new investment in generation. They're conscious of the hazard in eroding investor confidence through ill-considered intervention in the markets.

Question: In the New Jersey case, the supplier takes the risk; a contract is a contract. But, if the supplier goes away, a credit protection provision is provided. This is trying to capture the exposure that would occur in going from the transition when one knew the supplier was going away, until one could arrange a new contract, which is assumes there's some volatility.

However, if there's volatility, there's nobody around; the prices have gone up a great deal:- then the credit protection story does not function similarly. How is that addressed, similarly to the force majeure problem discussed earlier?

Response: Well, credit protection does exist. There are agreements between counterparties in the New Jersey regime. When the price goes above the predicted price, the parties post letters of credit or make advanced payments. There hasn't been a problem yet. If volatility increases, we'll see what happens.

Response: One of the interesting options that's being discussed in several states is a requirement for forward hedging a portion of the supply portfolio. However, a requirement to hedge is itself a form of intervention that is objectionable. It undoes some of the objectives of risk allocation in a market when utilities are told to let the market allocate the risk; but they're also told to forward hedge a portion of their portfolio.

Comment: Let's be practical. This is America. We have politicians. They tend to be in charge at times, and they react to what people need and want. Mainly the residential customer, and maybe the small businesses who vote for them or not. We haven't totally deregulated. It's not totally market-braced. It's a different type of regulation, and we attempt to have the market function as well as possible.

Response: When regulators tell you how to manage your risk, that undoes some advantages because companies have risk premiums. Additionally, the cost of hedging is itself a substantial cost, especially in the current market. When the industry discussed locking in long-term power supply contracts in capacity shortfall markets, we had the same issue. Markets will do what markets will do. We either allow them or not. This hybrid situation where we go back and forth seems to guarantee that we will continue on this path we've been on seven or eight years.

Question: These questions address the response to short-term immediate-crisis-level price increases, and how government allows those to

be addressed. My question goes to the other end of the spectrum, which is resource adequacy. Even the FERC is having a crisis of faith about whether competitive markets will produce adequate capacity, perhaps learning the wrong lesson from California. Nevertheless, they are ready to force regions like New England to adopt costly mechanisms for ensuring long-term resource adequacy. Many public utility commissions share the same apprehension, that there won't be investment in long-term capacity in the context of a competitive marketplace, even a well-functioning one.

In the UK and Scandinavian markets, there are no government mandatory requirements regarding investment incapacity. Is this connected to the vitality of the retail market? When competitive companies have large portfolios of customers are they getting vertically integrated, investing in generation, hedging their long-term risk, and attempting to have the market solve the problem of resource adequacy (rather than the government)? If that's not happening, will it become a concern of the magnitude we have here?

Response: In the Nordic market, deregulation started with extra capacity. We had dropping prices due to extra hydro. This led to the decommissioning of spare units that were too costly to maintain. There was a period of reducing capacity. The market got closer and closer to the minimum limits needed for those really cold winter nights when you see price spikes. This is an ongoing debate because hardcore marketers argue that we need to experience really high prices so people will understand the need to build something. Others think that this is a collective good; keep the market running most of the time. The TSO in Sweden must buy extra capacity of X numbers of megawatts each winter. That spare capacity is not used for anything else. That's worked for some winters, but it is supposed to be a temporary solution.

Concerning the market in the retail case, I haven't heard of any company investing because they have too many short-term contracts that they think they will keep for a longer period.

Some larger utilities are signing long-term bilateral contracts, like eight or ten years. The prices are a bit better than you could see on the futures market. There aren't really any contracts that far away that are standardized.

Response: The current approach to security of supply in the UK is that markets can and will deliver the investment and new resources that are needed. There is a debate about whether the market needs an explicit capacity mechanism. Regulators have resisted the introduction of those types of mechanisms so far. Consider the evidence in both gas and electricity markets. The UK is now a net importer of gas. The gas sector has made billions of pounds in new investments; new interconnectors, new LNG facilities that the UK gas market needs. With electricity, in 2001 and when prices were declining, companies were responding to price signals and taking plants out of service. As prices increased, plants were brought back into service.

The UK has reasonably healthy supply margins right now. That may mask the true situation because a lot of that capacity is in Scotland, and there is a congestion between Scotland and the UK. There is some nuclear and coal capacity that will come out of service over the next five years or so. The real test of the market is going to be over the next five years. However, some companies are planning significant investment in new generation.

The complicating factors are not the market dynamics but public policy issues, the most important being the allocation of carbon allowances. Currently, incumbent generators are being given carbon allowances free of charge. This puts new entrants at a particular disadvantage. These issues are having a greater impact on the pace of new investment in generation than market fundamentals.

Comment: In the U.S. Northeast, an allocation of carbon allowances within the Regional Greenhouse Gas Initiative (RGGI) system that assigns at least some of the value to public benefits programs is needed. Then there is a source of funding for energy efficiency

programs at a critical time. The RGGI innovations are going to translate into wholesale price increases, there's no way around it. In Germany, there's been concern about a zero cost result from giving allowance for nothing to generators translating into higher prices. This is because the opportunity cost of those allowances was now reflected in wholesale prices. Exactly the same thing is going to happen in PJM, New York, and New England. At the least, if RGGI goes forward, there needs to be a way of extracting some benefit from the assignment of allowances for consumers.

Comment: Interestingly, the RGGI discussions involve nine states, environmental commissioners and utility commissioners together. The discussion concerns allowances and whether we should do what's been done elsewhere. The original suggestion by environmental staffs was to allocate to the emitters, the current generators. However, in a restructured situation it's completely different. It would be a windfall. There's a lot of reasons why people want to allocate. Some of the allowances will go to energy efficiency, or to states for customer use. Clearly, the need for energy efficiency funds exists. A lot of states have a societal benefit charge. New Jersey does, but certainly could use more.

Question: One presentation characterized success in retail competition as being measured in part by high levels of switching and low retail prices. However, this success may have been due to an overbuilt generation system in which generation owners didn't fully recover their costs. If success in retail comes from high levels of switching, it results in uncertainty on the part of investors as to whether or not there's going to be a buyer for their product. Further, low retail prices won't sustain new generation investment. We need to see more customer base stability and sustained higher retail prices if we're going to get new investment. The things that characterize success in retail competition are anathema to getting new generation investment and stability over the long run in these markets. Is failure in retail competition based on those measures necessary to get new generation investment?

Response: Who said anything about low retail prices? You're right. The price signal has to be there for the investor. There's got to be a second generation of retail providers, better capitalized to participate in a market which is building infrastructure. Currently, generators are still looking to incumbent utilities for long-term contracts to back up needed investment. That condition will probably persist until retail access becomes a more real market.

Question: What about investor-owned utilities who have an uncertain customer base in the presence of retail competition and high levels of switching? They won't want to make long-term commitments in the light of that uncertainty. There's still a gap between success in retail competition and the investment we need in the generation system.

Response: Longer-term contracts with larger actors who have a broader customer base can enable the investments. However, like a pipeline, it's not one utility that invests in a pipeline; it's a consortium of utilities that contract for the pipeline supply. You can do the same thing in the next generation. This will take time to evolve and require larger, well-financed marketers.

Response: Most players in the UK retail market are well-financed, well-capitalized companies. They have significant investment in generation. The key characteristic is the matching of downstream customer base with significant investment in upstream generation.

Response: The low prices at the beginning of deregulation in the Nordic market were mainly due to two things. Instead of an average of fluctuating trends in high or low water levels, price fluctuations moved to customers in the wholesale market. There were low prices right initially due to a lot of water, and then high prices the year after, with less water in the system. There have also been low margins. Prices started to move around more in 2002/2003. This volatility led to increased risk and some companies went out of business. Margins had to grow in order to have extra

money for the investment. We've seen an increase in margins.

The problem is you still need the long-term commitment. I wouldn't call this an unexpected market failure for the Nordic market. It's something that you need to take care of. One way is to internalize the problem within the market. Currently, one only gets paid for the few hours you run the spare capacity, which is not enough.

In Sweden currently, you get paid a fixed fee for spare capacity, which is X thousand megawatts for the cold winter days. That money is kept even if it's not run during the year. This is not entirely a market-based solution. The lowest bidder gets the contract until the TSO has filled the quota each winter. Both supply and demand are considered. Large industries that are interested in cutting off demand at certain hours are allowed to bid into this capacity situation.

Question: Aluminum customers in the Nordic markets decided to extend their Christmas holiday as a way of dealing with the prices. The Pacific Northwest also has a hydro-dominated system. That was one of the solutions with the western electricity prices crisis of 2001. The problem is, their aluminum customers didn't come back. Did the Nordic customers come back? How are they dealing with the higher prices of electricity?

Response: They are complaining a lot. They did come back that time. Carbon emission rights are a big issue for electricity prices, especially in the Nordic market, where we don't have that much. We have a lot of hydro and a lot of nuclear. We don't emit that much carbon dioxide. But on the margin, there's a lot of carbon emitting production running, especially in Denmark. Remember, it's one wholesale market and one price. The marginal cost for the price is the carbon industry in Denmark. The entire industry has the extra cost of the carbon rights right now. This is a large complaint for the energy intensive in Norway and Sweden. They wonder why they should pay high electricity prices based on carbon emissions that don't exist within Sweden

and Norway. They say this will kill them and it's an ongoing battle now to get politicians to swing either way. So far, the market has been left alone. This is a large problem because these energy-intensive industries compete outside the European bubble where this is set.

Finally, confidence in the market is important. The politicians maintain this effectively in the Nordic scene. They keep their hands out and that has increased confidence in their discretion. There is a well-functioning futures market with standardized three-year contracts that turn around between six and ten times the physical volume. There is good liquidity in these contracts; this is the only place where you have this type of liquidity.

Question: What we've done is first asked the question, would we like to have retail choice in electricity? It seemed like a good idea for some people, and we argued about who it would be good for. So we went about the process of inventing retail choice for electricity consumers. Seven or eight years later, we ask, do we know how to keep the lights on? The answer is we're not sure.

We started off with the wrong question. We should have asked, if we move to a competitive framework, do we know how to keep the lights on, and what would that take? Next, could we allow retail choice and keep the lights on? The title of this panel, "Why does Retail Competition work in some places and not others?" is not correct. Perhaps it should be, "Is retail competition feasible while we still keep the lights on?" There is no place in the United States where we definitely know the answer is yes.

Comment: Competition for competition's sake is not where I'm from. If competition can provide lower prices and reliable service for customers, it's a good thing. I was persuaded enough that it could. We still haven't quite figured it out yet, though and it is a scary thing.

Question: My question is a low-tech issue: What are we going to do with the energy crisis? My home state is trying to implement a renewable

portfolio standard. The caps are coming off, so we're getting rate cases. There are four large mergers coming up. But the one issue that keeps me up at night is the cost of rising energy.

This came up the other day in an interesting context. A natural gas utility came in for a typical pre-filing; the company is doing the best it can to try to avoid a further downgrade. When they filed the month previously, the prices at Henry Hub were nine dollars. Of course, when they started five years ago, they were at two dollars. After Katrina, it's up to twelve dollars. They have to re-file and seek emergency and expedited relief. This will be the case all around the country and it hits vulnerable customers most. The usual answer is, let's throw LIHEAP money at; or a customer assistance program; or weatherization. This time might be different. What can we do? Can regulators avoid the perception of being gas station owners who are passing along prices?

Comment: Some states were facing a 25 percent increase before Rita on rates, even with companies that hedge. New Jersey has a good universal low income assistance program and they're not going to be able to afford it. Their customers pay for it. Even people making 30, 40, 50, 60 thousand dollars a year in expensive states are going to have problems. They won't be able to pay for their heat, or they're not going to be able to pay the mortgage. There are discussions with utilities and advocates but we can't figure it out.

Response: It's painful now, and it's going to get a lot more painful in the future. It's not within the control of governors, legislatures, or PUCs to change that in the short term. There was a policy decision ten years ago that said markets allocate risk better than regulators. We don't have tools to address high natural gas prices.

Comment: Some states have diversification in coal plants. However, they're having trouble with rail yards getting coal to the plants. Most contracts are on a best efforts basis. Even if you've got coal and other opportunities, there can be trouble getting it to plants that are fuel

switchable. They're going to burn natural gas instead of coal. It's a big monopoly, the railways, with a good lobbying group.

Response: Concerning the comment that we are without tools to address the price spikes in gas because of a decision made ten years ago. In the 70s, prior to the marketplace, it was just straight cost pass-through. There was no protection from price spikes then either. We have to be careful about pinning it on the competitive marketplace.

Response: I agree. If you talk about rate making, any state that has alternative rate plans or multi-year rate plans has some protection against the straight pass-through of higher fuel costs. Those states have dampened effects which otherwise would be even more dramatic.

Comment: These issues can be dichotomized in a couple of ways. One would be short term/long term, and the other is an income problem and a price problem. We've been talking about the price problem. Conservation and demand response could be a response to the price issue, as well as forbearance by companies to defer increases. Some companies have done a good job of that.

The income problem is the other problem. In some states low income and 150 percent above poverty are pretty well taken care of. They will have no problem paying their bills because they're paying ten percent of their income. There will be accruals and arrearages, and some will become uncollectibles; we all end up paying for this, which is fine. The real problem is the working poor, above 150 percent. We all know that HEAP and LIHEAP is available to the lowest income. TANF funds, Temporary Aid for Needy Families, is available only to families that have children. If you're elderly, poor, you're not entitled. One way to handle this is to take HEAP moneys; transfer that just to the elderly, and then use the TANF dollars (if you have them) for the others. That can address maybe up to 200 or 250 percent of income. That's the income side. The price side is a longer-term project. It is demand response, conservation, weatherization.

Comment: Consider the concept of saving in years of plenty to have money in years of famine. There could be secure escrow or balancing accounts that gas and electric sellers build over time with prices that may be above market so they can be drawn down when prices are threatening to the viability of low income customers and other customers. It's a long-term effort, and it's too late to do it for the current

situation. It's also hard to do without disrupting important price signals. It's hard to do that without money becoming an easy target for other projects. It really has to be secure. In the current situation, can SBC accounts be used to defer some of this? This goes back to biblical ideas of building up granaries when you have a good crop, and drawing them down when you don't.

Session Two. Resource Adequacy and Electricity Markets.

Electricity infrastructure resource adequacy was largely judged to be adequate for 2005, but the rate of investment in generation and transmission has been seen as too low to meet future requirements. Features in energy market designs operate to keep the reported prices low. Price caps, out-of-merit dispatch rules that suppress calculated prices, special contracts for "reliability" units, and regulatory uncertainty are cited as deterrents to market investment in generation. The problem goes to the core of the expectations for electricity restructuring and greater reliance on markets to drive investment choices. Can we identify the critical market failures (e.g., inadequate scarcity pricing) and fix these flaws to remove or minimize the need for regulatory intervention mandating resource adequacy investments? Can the remaining interventions under central planning and regulation be circumscribed enough to maintain a defensible bright line for market-based investment with the anticipated benefits of electricity restructuring? Or will the cumulative mandates further undermine market incentives and create a self-fulfilling prophecy of a failed market?

Most participants seem to recognize or suspect that this slippery slope problem is real, serious and here. But there is a strong temptation to avert our eyes from the market design problem in hope that it will go away. Those charting the path for infrastructure adequacy should recognize that this is a critical juncture for electricity restructuring. Where does the path lead? Without a vision of the destination, and a coherent story for how the next steps move in the right direction, there is little hope the journey will arrive at a good place. A grand policy decision to abandon electricity restructuring would lead to a very different discussion about what to do, and what to do next. But the unintended consequences of many small decisions mandating choices rather than fixing market failures create a stealth policy that would never be chosen and could produce the high costs of both bad markets and bad regulation.

Moderator.

As a brief introduction, under the vertically integrated structure capacity cost was implicitly included in the revenue requirement and spread equally among customers on an hourly basis. Capacity was virtually free. That sends the wrong signal for new investment, and discourages demand response in most cases. What is the price of capacity? Or more accurately, how do we price reliability?

A successful capacity market should have at least the following characteristics. Number 1, maintain reliability; Number 2, provide strong incentive for investment at the right location; Number 3, provide strong signal to demand response; and Number 4, support innovation and efficiency by market participants, driven by incentives rather than by command from the central planner. I hope our panelists will benchmark their proposals against those four characteristics.

Speaker One.

I like to think in terms of resource adequacy. In the regulated world, resource planners did a good job of adding the right generation and the right mix at the right times. We're trying to get the markets to work as well as that. We also need the benefits that were promised in terms of lowering costs and increased efficiency.

We have two paths for resource adequacy: the no cap path, which is a no capacity market. It could also mean no price cap in an energy-only market. This is the California-ERCOT-Midwest ISO method, as well as examples overseas. The energy plus capacity construct is the favorite of the Northeast.

With those models in place in various parts of the country, and a full boom-bust business cycle that we've seen to date, the good news/bad news is that we can draw some conclusions. There's been several problems. In energy-only markets, it's a concern for price caps and their impact on scarcity pricing. In capacity markets, it's the problems associated with location (being addressed in LICAP), and diversity in the PJM construct (looking to add something other than just gas plants).

In PJM the issue is to match capacity market commitments better with the business or construction cycles that they're trying to encourage. Problems also exist within the ICAP markets with vertical demand curve. Finally, there is a question of qualifying resources: are we just talking about generation, or are also transmission, demand response, et cetera?

We need to address location markets as part of the LICAP proposal. Different pricing zones will encourage new generation in areas where it's needed. Diversity adds, part of the RPM proposal, encourage operational flexibility in units that are built and encouraging fuel diversity. Finally, the sloping demand curve in New York is working better than the old vertical demand curve construct. Part of the PJM proposal is a four-year capacity to better match construction cycles.

These issues have prompted a potential capacity market evolution. There is a range from no cap, or energy only, to the ICAP market in PJM right now, to the LICAP market, which adds the locational component, and to an ever-increasing level of complexity that I'll call FLICAP, or flexible LICAP. Right now, we have no cap markets in ERCOT, California, and Midwest ISO. We have ICAP in ISO New England and PJM, and the first LICAP market in New York. In New England we have the LICAP proposal. It's been hotly contested, and is stalled until at least late '06. New York has a three-zone LICAP market. It runs with strip monthly and spot market auctions, and implements a demand curve in the spot market auction. In PJM, the FLICAP proposal is being considered. The latest reliability pricing model for it was published at the end of August. In California, a proposal by six independent generators and two utilities looks like a combination of the New England and PJM proposals. In MISO, the energy only market started in April may stay as an energy only market going forward. The White Paper is advocating an energy only construct. ERCOT will likely stay energy only as well.

There's three places this evolution can go. It can stay in the status quo. The Northeast stays with ICAP markets, New York has its three-zone LICAP, and ERCOT, MISO, and probably California, will stay energy only. Or we can continue to evolve, and LICAP proposals go through in PJM. Who knows what that means for MISO and California. Or we progress to what I call administrative return. This is a slippery slope. Similar to the chutes and ladders game, capacity market constructs stack up until they're so complicated that the market is effectively re-regulated.

The no cap or energy only market is great in theory, but uncertain in practice. It's economically pure, more or less a hands-off approach. To relax or remove price caps in these markets has difficult political issues associated with it. It requires the generation investor to believe in the possibility of high price spikes, and to make hay while the sun shines. However, it is difficult to get banks to finance for those

rainy days. The problem is cash flow volatility. It can be mitigated through long-term contracts. However, it has problems with investment droughts and investment stampedes as prices spike. The market requires a risk premium to deal with that uncertainty.

Continued evolution of the capacity markets is probably not a good idea either. Another proposal is AFLICAP, in which an age component is added to flexibility and location. At this point, we've re-regulated the market. Distinguishing between new and old is easy but difficult to implement. However, distinguishing between old and older would be more difficult.

Because we're trying to fix these markets in a down cycle, it looks like this is a consumer-funded generator bailout, rather than a long-term solution. "The anti-consumer, anti-competition, \$15 billion generator windfall." Generators push back and say, it's not fifteen; it's three. Much of the commentary and opposition to capacity markets is focused on the short-term. Yes, in the short term, generators will benefit, and ratepayers will see some rate increase.

The capacity market construct in New England and PJM should see more generation in the right places, encouraged by the locational component, or by transmission upgrades. We'll see demand response in some places to alleviate the problem, or we'll have some administrative intervention similar to the PJM proposal. Clearly the public can't stomach energy price volatility, and it's similar with capacity market volatility.

On a positive note, the markets in New York seem to be working. The slope and demand curve construct there has reduced volatility and improved predictability. It's still somewhat volatile. In the vertical demand curve construct, the tipping point between surplus and deficit, zero and the cap, was difficult to analyze from an investment perspective. The sloping demand curve has more price certainty; it's easier to sell to the bank. It requires advanced game theory to figure out who's coming and who's going, and the impact on price. But at least you know what the impact on price is going to be. It is helping

as it was intended, to increase predictability in capacity markets. The demand curves with longer tenures proposed in PJM, and vocation-based markets, are a step in the right direction. The political backlash in the Northeast is influencing these proceedings, and leading many to reconsider the energy-only construct.

I end with a couple of thoughts from conversations I've had this week. The first from a hedge fund manager who is heavily invested in energy. The thing that keeps him up at night in his investments is capacity markets. The second came from a conversation concerning a diverse portfolio of assets in the Midwest. The manager said, 'You know, the biggest risk that we have in this whole investment is capacity market development and the regulatory risk associated with that.' I walked out, and said, my God, in an era of \$12 gas, price volatility, uncertainty in environmental regulation and possibly carbon trading, this guy's worried about capacity markets? It's time to get this thing fixed.

Speaker Two.

I am going to summarize a couple of major points, and then talk about resource adequacy. The recent strategic plan from the new Commission at FERC is helpful to set up the conversation. Their goals are laudable, and seem compatible. But there is a difficult and important tension between mandates and markets, and the efforts to develop infrastructure and promote effective competition. If you want to have markets, and you don't design them properly, you shouldn't be surprised if they don't work well. If you want to solve the problem without fixing the market, you might do something that you don't like so much. The other approach is to fix the market.

It's not just between infrastructure development and markets in competition. The same issue comes up when thinking about reliability issues. In the Blackout task force report they emphasize the importance of designing markets so they reinforce reliability, as opposed to competing with it. This involves using markets for public

purposes, but it's complicated for the reasons discussed earlier. The emphasis should be on incentives focusing on investment. It's helpful if markets also make operations easier and better, but the justification for electricity restructuring has to be to improve investment.

How do you create an effective electricity market design with the associated transmission access rules? This is the problem that Order 888 was intended to address in part, and later the RTO rules and their discussions. They show that an electricity market must be designed. The market cannot solve the problem of market design. The second part of the tension is that there are imperfections even in the best of market designs. The trick is to provide compatible market interventions to compensate for these imperfections.

Market failures include network interactions, dealing with security constraints, lumpy decisions, chicken and egg issues, the market power problem, and a variety of unpriced products. The tension is between central coordination, and a more or less market-based solution.

A dangerous definition of market failure keeps coming up de facto in these conversations, that the market fails to do what the central planner wants. We're not getting investment; we're not getting the response we want; it must be that the market is failing. That is dangerous. It allows solutions that ignore the market design problem. If you need generation there, build it there. That's the answer as opposed to trying to address why the decision wasn't being made. The tension reminds me of an analogy that concerns the environmental context, and sulfur emissions from coal power plants. There were two broad strategies to deal with this. One was the command and control approach: all coal plants have to install scrubbers. The alternative approach was the cap and trade system, a cap at 50 percent of prior emissions, and the creation of allowances, and then people trade the allowances. This was cost-effective, and allowed for flexibility and innovation. Granted, the cap was a pretty serious intervention. It was an

innovation that is compatible with the market. It also doesn't let one just walk away and live with a lot of sulfur.

The problems surrounding Order 888 and the subsequent discussion are still about market design. I was depressed by a comment from the Chairman of the Federal Energy Regulatory Commission about the open access transmission tariff investigation. He says, 'We are not talking about market design. We are not talking about restructuring. We are talking about preventing undue discrimination and preference.' This is completely divorced from the reality of the situation. I hope his rhetoric wasn't intended to be taken literally. If it is, there is a serious problem because the market design is what leads to the problems. Examples include transmission investment mandates under central plans for system expansion. Consider the New England transmission cost allocation proposal, which spread costs across everybody, but it's not socializing. Even better is the PJM regional transmission expansion plan which allows you to make economic investments for unhedgeable congestion. There's a set of serious problems there. The slippery slope issue is similar in New Zealand, where if you start mandating and subsidizing transmission, the same has to be done for the generation and demand side. It's hard to stop that process. Finally, there's generation investment mandates under resource adequacy plans to meet reliability standards.

Let's consider the resource adequacy problem, and installed capacity reserves. This is an example of the unpriced products problem because price caps are on, and there is missing money. If you put a price cap on, plants don't get enough income in order to justify running those reserves. Several reputable analysts have written reports, often every year, that go through this story and do the calculation. How do you do to fix that problem? These problems are connected to each other. At PJM, one justification for longer-term commitments for installed capacity under the reliability pricing model is to satisfy requirements for transmission expansion planning. This is in order to make commitments for transmission under their

central plan to address reliability and unhedgeable commitment congestion issues. These issues are clearly connected, and spring from problems in the market design.

One approach is not to fix the market design, but to do something else. In the case of generation resource adequacy, it is installed capacity markets. It seems a failed model. However, reforms of these reforms have been following. The peaking unit safe harbor model for ISO New England makes the world safe for the exercise of market power. Fortunately, the Federal Energy Regulatory Commission recognizes that the growing pressure for things like RMR contracts and similar interventions is part of the problem, and not the solution.

The latest reforms from New England and PJM contain wonderful paragraphs in the reliability pricing model about how tradeoffs between different kinds of generation are going to be made. Well, the ISO is going to publish this sometime in the future. And the forecasts for demand? We're going to publish this sometime in the future. There's a lot of 'the detail is yet to be specified, and it's going to be more prescriptive as we go along.

Given assumptions about some characteristics of the market design that are politically unassailable (i.e. we can't change the market design; we can't fix the market design; we have to live within the box that we have created), these proposals from New England and PJM make sense. They're logical and sophisticated. But they're not going to work or accomplish what people want. They will become more elaborate and prescriptive. Then we're back to the slippery slope.

A market-based resource adequacy program could be designed that would not slide down the slippery slope. This discussion has been underway in Texas and MISO. The alternative is an "energy-only" market. This is in quotes because I do not mean to literally abolish FERC and the state regulators. That's the Cato solution, which they didn't get, so they want to go back to vertically integrated regulation. What I have in

mind is something more like the cap and trade story, which is to fix the market design.

The fix of the market design is to recognize that the costs are very high when you start curtailing inflexible customers because you've run out of operating reserves. This is an acceptable reality. We can figure out what those costs are to a first approximation, the average value of lost load. That should be included explicitly in the marketplace. The demand for energy and operating reserves can be included so that we have a demand for both at the same time. Most of the time, the market will have capacity, everything's fine, and the price is 30 bucks. Every once in awhile, operating reserves will be running out, and the system operator will be reducing load. Here, the price goes up a lot. That's consistent with the basic idea design. It's not an innovation to suggest this. I'm not talking about \$2,000 price cap here; most importantly, it's not even conceptually a price cap. \$10,000, a round number for the average value of lost load, would only occur in involuntary curtailments. It would stay there until involuntary curtailments ended, which would be virtually never. It's like a price cap, but not literally. Any generation bought that was more expensive wouldn't be worth it; it would be better to curtail.

Let's focus on interventions to address market imperfections. There are two important issues. One is market power mitigation. We would do more of what we do now. That would not be dramatically different, and would be necessary and useful. The other part is mandatory load hedging. It's a very good idea. The critical feature is that the hedges would be financial contracts at the load location. They would not be connected to any physical plant; nor to investments in transmission. This is similar to New Jersey and the BGS auction. It's the delivered price, and the suppliers solve the problem on the other end. If suppliers were facing this energy-only market, they would have an incentive to implement forward contracting. We wouldn't need RMR and the other stuff; there's no capacity requirements. There's no worry about performance monitoring or access

to the electricity market when the system is highly constrained.

Focus on the market failures. Fix the market design. Provide market-based interventions, or watch the lights go out on electricity restructuring.

Speaker Three.

I agree with everything the previous speaker said. I want to emphasize that those solutions entail a wider paradigm shift than is apparent. Let's start off with a fairly innocuous statement: In most regions of the United States, the power supply surplus will be disappearing between 2008 and 2012. Is there something missing in that statement? Most of you see this as a factual statement. However, inherent in it is a whole body of assumptions. If I simply add three words, to '*At current prices*, in most regions of the United States, the power supply surplus will be disappearing,' then it makes sense to me.

A surplus in the absence of any price information has no meaning to me. The equilibrating mechanism is price in the market. Restructuring has given a transparent, robust, and trusted price in most cases; an LMP price. Most people in the market have good confidence in LMP prices, but it's only one price in the industry. In other areas, problems with indices and the integrity of the prices exist. A fundamental objective is to develop a market with robust price signals along the chain; the bilateral marketplace; the day-ahead market, real-time, options, derivatives, swaps -- all of those things. If actors trust those prices then the market will make good decisions. When we're talking about something as important as resource adequacy, why do we leave out prices to guide decisions? Why isn't the robustness of the price signals the issue?

We establish markets so the price signal will help guide decisions, and make better decisions than in the absence of prices. Decision-makers must ask why isn't price doing its job? If you don't trust prices, then you use some other

mechanism to guide the decisions. There's no other initiative facing wholesale market design bigger than the issue of resource or supply adequacy. We're in a capital-intensive industry where investment is expensive and decisions last for a long time. In turn, they influence current consumption decisions, and future investment decisions. You don't get rid of the mistake for a long time.

Another slippery slope is the relationship between generation and transmission adequacy. The relationship between long-term transmission service and long-term transmission rights related to the supply of generation at various locations is also slippery. If RTOs have to establish the demand curve at which capacity was purchased, and then have the real-time responsibility to commit units, will they create a demand curve that doesn't justify their commitment decisions in real-time? Will they say, 'we really didn't need half the capacity that our demand curve said we needed?' Even the RTO's role has to be questioned with demand curve setting and the actual operation of the system.

In New Zealand and Australia, it was surprising to see the angst regarding centralized security constrained economic dispatch, and the implementation of LMP (locational marginal pricing) across regions. Utilities have been optimizing fleets for years, and this was the next best step on that path. This is a core issue because it deals with jurisdiction, the setting of reserve margins, and provider of last resort responsibility. It is the core institutional structure of our industry. Implementing LMP simply takes security constrained dispatch from a local to a regional level. Sophisticated utilities have been doing this similarly for decades. However, resource adequacy is fundamentally different.

If there is going to be a shortage between 2008 and 2012, then we've ignored fundamental issues. Again, I applaud New England and PJM for highly sophisticated proposals. However, a different starting point may lead to different analysis and results. There are two possible positions. Either a market cannot deliver socially

desirable outcomes and we need a central planning mechanism instead of a market. Or, we start from the proposition that markets could do it if not for some issues. Either market failures are insurmountable, or one can identify market failures responsible for socially undesirable outcomes and determine whether they are immutable.

The MISO has taken the position that markets can deliver. RTOs must work down to market failures and see whether it's feasible to remove, reduce, or change those obstacles such that a market can give you the results that you'd like. In investigations at the MISO, there is lots of anecdotal evidence but little hard analysis that suggests these market obstacles are immutable.

An important issue is the existence of price or offer caps. We are told that it is politically unacceptable to remove the caps. This brings us to the missing money, and stakeholders who can't make enough money in the market to support this policy. The price cap problem is not that people won't make the money in the spot market. The real problem is that they are a form of hedge. It is a political hedge, as opposed to a commercial hedge. It means that people know they don't have to engage in appropriate commercial behavior because this backstop is always there. It keeps people from seeing the consequences of their actions. In the New Zealand market, the major backsliding has been a result of market actors who did not hedge. They go to the government and say, 'we need price caps; there's obviously these issues.' The government should respond by saying, 'why weren't you hedged? Was there a problem in the financial instrument or derivative market that prevented you from exercising risk management?'

The second issue in market failures is price volatility. Price spikes necessary to compensate peaking units are characterized as politically unacceptable. This is a red herring. These units are going to get their money in the capacity market, or the spot market, or the bilateral market. You're not going to have plants that stay on line that are going bankrupt. The question is,

how do we actually remunerate these plants? Is this done via an uplift, a tax, or a capacity payment? These I can't hedge as a consumer and they keep people who are doing appropriate risk management out of the market because it's a tax. Alternately, it should be addressed as a spot price that plenty of people are willing to hedge with physical or financial portfolios. If that market is too risky, there should be plenty of opportunities to get out. To the extent that we can encourage proper risk management techniques, overall costs should come down. There's a benefit when we don't hedge price volatility through physical means. They are an inefficient risk management tool to manage price volatility.

A third point is 'regulatory remorse.' How can we be sure that regulators won't renege if we commit to a higher price cap or elimination of price caps? Stakeholders will write these contracts, prices will go up, and they'll be punished. Their decisions will be void once they are subject to regulatory remorse.

The fourth point concerns planning reserve margins. Supply/demand balance never gets to a point where prices rise and investors see long-term signals. How do we change institutional structure to allow shortage conditions to manifest themselves in long-term prices?

All these issues exist whether you go down a market path, or more centralized planning with an ICAP or RPM. Trying to limit price levels simply means the balloon pops out some other way. It doesn't change the fact that people need to get paid. There is no free lunch. The risks are inherent in the industry. Policymakers need to determine a design that creates least-cost, most-efficient behavior, not just in operation, but in investment and pricing, and so on.

A fundamental question: why is the long-term price signal in power so weak or non-existent? Why is there so little real forward information? For commercial people, there's nervousness with regard to price robustness as they get beyond 18 months. The industry is characterized by asset specificity. Assets can't be used

anywhere else, and they have large capital outlays. There are a high degree of network externalities and a large amount of natural volatility. We would expect, and actually do see, a high degree of contract cover. The question is whether or not we have the appropriate length. That's something the market can determine itself. There doesn't need to be a prescription for the length of the contract, but it is a policy decision as to whether we're seeing the right length. Is it appropriate to have 80 percent of capacity contracted for one year, or for three years? If the market is telling you one year, that's fine. But if there are market inefficiencies that create that, then we need to look at those. We need to identify impediments in the institutional infrastructure that prevent commercial contracting from implementing long-term contracts. Under regulation, really, you had a long-term contracts. Regulation provided the ability to receive monies into the future. Wall Street knew you had it in the rate base and you could finance.

On April 1, 2005, MISO began operation as an energy market based on LMP. They have a large geographic, political, and even electrical diversity across their footprint. They have retail choice/not retail choice; they have three different NERC regions. At present, they have no RTO-administered capacity or ancillary service markets. They codified NERC requirements through Module E of their tariff. With regard to ancillary services and capacity, business is as it was prior to April 1st. They have been engaged with stakeholders for two years in the Resource Adequacy Working Group, and the Supply Adequacy Working Group. The wholesale market platform paper that FERC put out after SMD firmly set the issue of resource adequacy under state jurisdiction. MISO has a mandate from FERC to address the lack of a capacity market by June 2006. Some states are considering the New Jersey BGS style auction to acquire capacity. Finally, MISO released a draft White Paper on resource adequacy in August. It suggested an energy market solution that relies on long-term contracting and considers the relationship between generation and long-term FTRs. This

suggests they will examine obstacles that prevent long-term contracting from meeting the needs of capacity.

Speaker Four.

I will discuss resource adequacy from a different perspective. My analysis is confined to the legal and political framework of a pragmatic regulator. Capacity markets are a necessary evil in today's organized markets. I place emphasis on both words in that characterization, "necessary evil."

Reform is necessary because the ICAP model is broken. There is a looming crisis in generation inadequacy because some load pockets are constrained, and that is bound to spread if we do not bring about some reform.

However, I also recognize that capacity markets are evil because they are an intrusive form of intervention which can lead to inefficient and costly results for customers. Capacity markets could also become an embedded feature, especially if they produce new capacity resources. I place "desired" in quotes because a new capacity resource at very high cost may not be desirable to all consumers.

While there are inherent market design flaws in the capacity constructs in place today, the need for reform is precipitated by a number of other factors beyond the capacity market design. I'll point to three: transmission policy shortcomings; market power mitigation rules that may reduce incentives for new investment by distorting price signals and creating uncertainty that drives away investment; and third, the persistent inelasticity of demand that prevents a mature, efficient and reliable market from developing. We need an integrated approach to resource adequacy that addresses all these concerns simultaneously, and functions in a self-correcting manner.

Before discussing this, I want to go back to the necessary evil characterization because it is crucial to understand the environment we are working in. Considerable work exists that

defines the merits and deficiencies of an energy-only versus capacity market approach. Like any politician -- and regulators are politicians -- I want to vote with my friends on both sides of these issues. There is a natural tendency in the political process to seek equilibrium. We call that equilibrium-balanced public policy, there's a reality in the political process.

A second reality is that regulators have a tendency to be risk adverse. It's also true among energy company executives and, importantly, the leaders of RTOs. Nobody wants to see things blow up on their watch. Big risks increase the likelihood that that will happen.

A third reality is that there is a short time horizon to measure the success or failure of a proposition. Elections are every two or four years. Regulators are appointed or elected on four, five, six-year cycles. Even the U.S. Senate, with staggered six-year terms, is not immune to intervening political developments, especially if elections are just around the corner. I'm not suggesting lifetime terms for politicians or regulators, this is simply a consideration for any public policy problem.

We need to consider these three realities for the debate of bifurcated versus energy-only markets. First, the natural tendency towards gradualism, compromise and balance in public policy-making. Second, that political leaders and regulators are risk adverse. Third, the short-term time horizon within which to measure success.

Why is a capacity market necessary today? A flash cut to an energy-only market is not politically sustainable in the short run. It is a bold and risky step, even if it is the right way to go, and there is no guarantee of success on the time horizon necessitated by the political system. Political realities necessitate the pursuit of another model, the capacity market.

Let me offer a brief illustration to demonstrate how political realities interfere with the right end state. During the administration of the first President Bush, the Department of the Interior introduced a bold new way to manage forests on

public lands in the West. Decades of fire suppression had produced forests with too much fuel in them. When forest fires occurred, they were massive, dangerous, hard to control, very hot, and they denuded the land of vegetation for decades. It was poor public policy. The new policy was to allow forests to burn so they could naturally rejuvenate. If allowed to work, it would have addressed decades of bad public policy that interfered with Mother Nature. A prominent administration official, after flying over forest fires that were being allowed to burn, made the unfortunate comment, 'Burn, Baby, Burn,' in reference of the new policy. What happened? The fires overtook homes and burned communities, and the administration had to reverse course. Why did the policy fail? It was too bold and risky, and the public did not have the patience to see if it could be corrected successfully.

Similarly, if we go to an energy-only market immediately, prices will rise during periods of resource scarcity to uncomfortable levels. If generation rushed in after that price signal, then we would be okay. There is no guarantee that that will happen. These new resources will not come quickly enough because there is uncertainty in the financial community, high sunk costs, and high barriers to entry. No regulator will endorse a model that produces high prices without assurances of some relief, even if it is the right thing to do. You will not find regulators saying, 'Burn, Baby, Burn' when you see prices reaching several thousand dollars for sustained periods.

A pragmatic approach concludes that a capacity market is necessary. They have their own problems, and it is crucial that affirmative steps are taken to mitigate them. The capacity market is a means to an end, not an end in itself. A mature energy-only market is the right end state. The debate is about how to get there within the legal and political framework.

How do we address the evils in our design of the next generation capacity markets? Capacity markets send distorted price signals. Almost by definition, they are inherently unnatural in

economics. No other mature commodity market separates the commodity from the capacity to produce that commodity. Consumers can't differentiate between the value of the good itself and the capacity to produce that good. Electricity consumers can't differentiate the value of generation or transmission separate from the energy commodity. However, an efficient market depends upon efficient pricing of each component.

Second, a capacity market will overvalue or undervalue generation resources. That distorts market pricing of transmission and demand resources. Another concern is that many proposals dampen price signals necessary to make demand response programs economic. A state regulator's mission (often prescribed by statute) is to help develop a competitive *retail* market for electricity supply. The duty of the FERC and the RTOs is to develop competitive *wholesale* markets. The two responsibilities are inextricably linked. Retail markets will not be successful if the wholesale rules are poorly designed and vice versa.

A third evil is the tendency, whatever model gets approved, to take on a constituency that supports it. Even a flawed design can become an embedded part of a market that is difficult to change. That's occurring now with the ICAP model in PJM. Rent-seeking occurs whenever a regulatory body imposes administrative control over a market. Beneficiaries of those rents will not support reforms that undermine their economic position. For instance, generators in the western portion of PJM receive compensation for capacity. There are consumer rents on the load side, as well. Load is receiving service in some load pockets that doesn't reflect the full value of capacity.

Given these concerns, what kind of capacity market should we have? First, we should have a capacity market that is self-healing. It should become less relevant over time. Market design features that can become an embedded form of incumbency should be prevented. However sunsets, automatic or periodic reviews of the design would lead to uncertainty, and wouldn't

necessarily bring about meaningful reform. Instead, implement a set of criteria or benchmarks that trigger specific adjustments to the capacity market design features. These adjustments will de-emphasize capacity as the market matures over time. A colleague coined the term "glide path" to describe this approach. An example of this might be adjusting the reserve margin, or making changes to the demand curve, as we see concomitant increases in demand response or interruptible load. There are other ideas that time doesn't permit. The point is, an administratively imposed and unnatural capacity market should become less relevant and wither away as you achieve measured progress toward the policy goal of having an efficient energy market.

The capacity market needs to reflect variations in locational value. We need locational price signals if we want investment where investment needs to go. Given the underdevelopment of demand resources in most markets, and the unleashed potential for efficiency gains from an active demand side, we need a capacity market that facilitates demand response. This is a challenge because capacity markets suppress price signals.

A market that is fair and neutral to all market participants is necessary. We may need to incentivize the development of the demand side of the market through regulatory policy because it is so undeveloped. If I am going to put my thumb on the scales at all, I'll emphasize the demand side of the market.

Market power mitigation that does not hinder investment incentives is important. We need regulation to prevent market power abuses, primarily because of demand inelasticity in the electric supply market. While we need market monitors, we need to make sure the policies they execute do not mute price signals and drive away investment. In the glide path model, the role of the market monitor is de-emphasized as the market matures over time. If we had an active demand side, consumers would have the tools to fight high prices. Then we do not need market monitoring to take that role. We need to

consider how the function can be legitimately and appropriately de-emphasized over time.

Finally, we must consider transmission and transmission pricing policy. There are reliability benefits to certain transmission investments that should be appropriately socialized to a larger set of users than the direct economic beneficiaries of a specific investment. The opposite is true, too. There are economic beneficiaries to investment in transmission that is driven by reliability needs in the system. One of the critical issues facing FERC is the resolution of transmission policy in organized markets. The right answer is probably a hybrid model that obtains the benefits of open markets and a regulatory approach. FERC can make clear where it wants to go with transmission policy. The RTOs and states can design the remainder of the wholesale and retail markets around those decisions about transmission.

Discussion.

Question: A couple of years ago at FERC they acknowledged that we needed capacity markets in the short run to get over a number of issues, specifically, the lack of load response. I want to consider political acceptability. In 1998 in the Midwest there were no price caps. Utilities had an obligation to serve, and ended up buying power at \$6,000 a megawatt hour. They took the hit. Days later, steel mills and others ran to FERC and said these rates are unjust and unreasonable; you must cap them. FERC did not do that, and concluded it was a temporary situation. In a retail access environment, do you believe that there will be the political fortitude to accept \$10,000 a megawatt hour? Let's just talk industrial customers who are going to say 'you're going to bankrupt the company and put workers out of business.'

Response: Let's sort this question into two parts. First, if there's no group where we can't say, 'go solve this problem for yourself in advance and hedge, and if you haven't, that's your problem,' then we should not do electricity restructuring. If that's what we believe, we should do something

quite dramatically different than a capacity market. My answer is I think we can say 'no, you should have hedged.'

Second, there's the transition problem, and the self-healing process. That's a real challenge. There are ways to do that. One solution is to have mandatory load hedging contracts for a large category of the load. That's not politically sustainable in some regulator's worlds. Alternately, I like the New Jersey model. It's not for all customers; it's for some customers. It's got a duration, but it's not indefinite. With that system, the residential customers we're most concerned about are hedged forward, and the industrials and large commercial customers have an opportunity to hedge themselves. Would that be enough as a transition mechanism? I hope so because it's hard to think about more that still preserves the market.

Response: Nobody is envisioning the same sort of world with regard to pass-through of costs that occurs today. There has to be some transition pathway in which the end use customer, only if they choose to, sees those prices. Prices don't flow directly to the end use customer unless the customer chooses.

Question: Not only should capacity markets ultimately fade away, so should market monitors. I disagree with the premise that there's not a required level of reliability. All market regulators currently impose an external reliability requirement. The question is whether these requirements are consistent with the equilibrium level of output in an energy-only market. It's probably naive to expect that an energy market is going to result in a level of reliability which regulators and politicians would find acceptable. The missing money is a function of excess supply, which is a result of capacity being built for liability objectives rather than response to a price signal in the energy market. Aggregate offer caps or market power mitigation are not a big part of this issue. In the last six years, aggregate prices in PJM were low and never got close to the offer cap. PJM is currently working on an explicit scarcity pricing piece. It looks like the demand curve in the

energy market discussed earlier. This might be a way to handle the glide path concept towards a smaller reliance on the capacity market, if not entirely eliminating it. The demand curve allows for high prices at times, but those times are limited to scarcity in the market.

In the energy market options discussed earlier, one model managed prices through a demand curve that reflected reserve requirements. Another model seemed prepared to simply let the issue go, and reduce or eliminate market power mitigation. The first can work, and it's consistent with the liability objectives. The second can't work, and doesn't make sense as a market design objective. It permits the exercise of market power as the means to getting additional revenue. Do you agree, for the foreseeable future, on an externally imposed reliability requirement? If so, what are the implications for your models? Should we be concerned whether the lights are on, or should we be prepared for blackouts if that's the energy market solution (which it might well be)?

Response: That's an easy one. We're going to have externally-controlled reliability requirements for the foreseeable future. The Northeast blackout taught us that the public is not going to tolerate a blackout. With regard to capacity, capacity shortages don't just crop up. Participants can see capacity shortages coming, there's information out there in the market. It's useful to separate between planning reserves and operating reserves. Shortages could occur with regard to operating reserves. However, that is a different issue than research adequacy for planning reserves. We should know about capacity shortages a year, or some months, in advance of it.

An important issue is the nature of market monitoring mitigation. It needs to be reviewed so regulators don't confuse scarcity with market power. Scarcity signals need to go through, but you don't want market power signals to go through. Finally, there's nothing in the demand curve model I disagree with. There's nothing inconsistent in terms of that approach and the approach that reviews market power mitigation.

Response: I'll emphasize the planning versus operating reserve issue, and give different answers to the two questions. For operating reserves, we have an externally-imposed reliability requirement, and we should, given the technology. It should be modeled to meet our objectives in terms of the value of lost load, and other important goals. It's an important part of the story; we should do it all the time. Pricing reserves when they are scarce, and getting that information back to participants, as opposed to giving them away for free, is important.

There's a separate question about the long-term planning standard and the installed reserve capacity. This is the equilibrium question. What if the equilibrium result is higher or lower than the current planning standard. What should we do? Well, my advice would be do nothing. The way it's defined nowadays, it's divorced from having a response in the marketplace in terms of the demand side. In PJM, they use ALM, (active load management) which tries to put a demand curve back in but does so poorly. These things are not conceptually compatible.

Question: Let us take the energy-only model for a second. If the price cap is very high, or no cap, you would expect people to use long-term contracts. Would this encourage investment?

Response: That's the fundamental premise, yes.

Question: What's wrong with that?

Response: Well some regulators would not require competitive suppliers to hedge in that way. I don't know that there is a problem.

Question: Why wouldn't a regulator expect that suppliers demonstrate or prove that they have done their best to hedge against high prices?

Response: First, I don't know if most statutes would permit regulators to exert that kind of regulatory control over suppliers. Second, there is a creditworthiness problem for some suppliers. Further, there is a social problem when a steel mill has to shut down and a thousand people are out of work. If a supplier

has not hedged appropriately, and you want to exert the tough love and say sorry for your luck, that's the wrong answer for a community with a thousand lost jobs.

Question: If you have the provider of last resort obligations, or auction off contracts in one, three, and five years through something that's like BGS with different rules, why do you care if the price goes really high, like \$10,000? Are regulators and politicians worried about high and volatile prices, or transparent prices? If the price spike has been hedged through the earlier auction, it shouldn't matter if prices go high in the spot market. Do we care because it might hit the front page of *The New York Times*, and it's transparent, and these issues seem unpalatable to the public?

Response: In Australia, there were times when the price went up to \$5,000, and it never made the press because everybody was hedged. Part of it is, who's going to the press and making these comments? If nobody is, you're not going to get a lot of sympathy from the press if a trader is complaining, 'I'm paying 10,000 right now.' If the load is hedged, it's not as politically volatile.

Question: Suppose you were offered a solution by a regulator that allows for two conflicting options. One is the energy-only market; it includes shortage pricing, improved reserve markets, real-time pricing, and improved demand side response because spot prices will pass through. Simultaneously, they adopt aspects of the capacity market. Then they need a triggering mechanism that tells whether one is working, and when they can get rid of the capacity market. The trigger is called a peak energy rental subtraction. It's done differently in the different RTO proposals. In the New England proposal, the amount that you're paid for capacity is reduced by the profits you make from the energy markets. This integrates the two models. Is it possible for everybody to have their way? You've got to have a BGS auction, or something equivalent to that. Everybody is covered by contracts, and they're covered for spot prices. This includes things to put the energy-only market in place.

Response: I think something like this might be workable. The New England way of doing this is by refunding the energy rent. It is relative to the variable cost of a benchmark peaker, \$85 for the sake of concreteness. And it's *ex post*. The way it's done in the proposal under PJM is *ex ante*; it's a projection of how much money you will make, and it's taken out of the price in the capacity market. If one did it the PJM way and the capacity reserve market and the operating reserve demand curve were internally consistent, the net price of capacity in the PJM proposal would be zero going forward. The price of capacity in the New England way is always the capital cost of a peaker. The PJM approach allows for the phasing out feature. In New England, you have to keep it there because it's always got to get the capital cost of the peaker.

Response: The structure you propose is so complex. It's like eliminating stakeholder meetings at an RTO. Alternately, the glide path approach is the political reality that we live with. Whatever decision is made now, we will live with it for 20 or 30 years because we're going to invest and write contracts. It's not going to go away nicely when the RTO wants, as you think it will be. There is an approach out there that integrates the two models. However, we can't make a decision too quickly and put something in that's not only second best; but really evil.

Question: Take the PJM model. Assume a four year forward auction for capacity. Why wouldn't that be consistent with keeping an energy market where the cap is still high, but indicative? Can one take the auction, or do you wait for the spot price? Why are they not compatible?

Response: You'd have to see the rules in terms of the relationships. For example, are people forgiven their capacity payments, or their capacity requirements as they move into real-time if they have procured on the other side and don't choose to go through the RPM mechanism? The RPM mechanism doesn't address bill times because it's a four-year look-ahead but a one-year product. From a commercial standpoint, you're buying on a one-

year basis, with a four-year look-ahead. It's not going to give you the investments you need.

Question: Is the four-year forward aspect of the PJM proposal a positive thing? In the Midwest, capacity is worth zero right now because there's so much. It won't be worth anything until we start to see problems. At that point it's too late to elicit investment that will prevent problems from occurring. You're going to get public intervention in some fashion. The genius of the PJM plan is that you're looking out four years. If the value four years out is zero, then fine; that's what it works out to be. If it's on the positive side, you're going to get that signal early enough. It is more likely to generate investment than an energy market that gives you no signal until it's too late. If I'm a generator, and believe it's time to make an investment, and I know price caps are coming in six months because officials are upset with high prices, I won't make that investment, even with a price spike. Why isn't the PJM approach the way to go here?

Response: You're not contracting for a four-year product; you're contracting for a one-year product. There is a difference between the value of energy in 2015 versus 2010 or 2011. You're not making a four-year investment decision. You're merely making a one-year at a time decision with a four-year look-ahead. That's different than forward contracting for a product for that fourth year in an energy-only market.

Question: There are no such contracts at this point.

Response: This is an indicator we have no liquidity in these products.

Comment: Or that the spot market is flawed, and that's impacting the forward market.

Question: Ideally, generators in the market aren't looking for \$10,000 hours. They are looking for forward contracts and people to hedge those positions. The problem is that there is a willingness by regulators to provide what is essentially a free regulatory hedge. It protects customers from seeing prices that would

otherwise flow through. As long as a 'free' regulatory hedge exists, there are liability concerns. How do we avoid that in the future? We're not dealing with a central regulator or five FERC commissioners who understand the markets. We're dealing with 50 different state commissions and different RTO footprints. It's easy to get the headlines and political backlash that have been discussed. As a result, the durability of an energy-only market is suspect to the investment community. An energy-only market makes economic sense, but the question is what's workable in today's realities.

Comment: Every time I talk to a regulator, they say, 'that makes a lot of sense. It is just politically not acceptable.' Have we all tried, with the same voice, to say the same thing to the policymakers?

Response: Well, load isn't going to speak with that voice because they're being provided a free regulatory hedge. It's a price cap, or local market power mitigation, or not letting reserve set the dispatch. Load is seeing the benefit in the short term, not necessarily in the long term. Planning horizons occur in terms of quarters, not even election cycles. From a business standpoint that is a driver we can't ignore.

Response: In our regional stakeholder discussions, load has been generally supportive of an energy-only market. So have the regulators. Obviously there are many questions. The biggest nervousness comes from generators. It is a useful sign that the OMS has clamored for more debate and discussion. If the steel mill goes broke because of \$10,000 power, or the local resident sees \$5,000 prices on their bill, we're going to fail. We have to provide a mechanism by which these people can hedge, and do so in a commercial manner, as opposed to a regulatory or political process.

Comment: We are seeing customers hedge, more so in the past two years as the markets mature. These customers are not only looking for hedge products but they also have credit requirements. They don't deal with suppliers who don't have good credit, aren't active in the wholesale

market, and don't understand the wholesale market. They're becoming sophisticated in requiring those characteristics from retail suppliers. A further question is what size of customer has experience seeing real prices, whether they be one-month, two-month, three-month or hourly prices. The more familiar they are, the more likely they are to request sophisticated products and sophisticated suppliers. Even if suppliers go bankrupt, customers still have contract specificity. Finally, there are a number of reasons why businesses close. Electricity prices are one of them. Heating prices will be one of them this year. I don't know how that gets regulated.

Question: One problem in the market is the act of long-term contracting. We have forward markets up to 18 or 24 months forward. But we don't know why people aren't contracting forward. One reason is that there's retail access. A 20,000 megawatt utility can't tell whether they'll be serving 15,000 or 22,000 megawatts of load, either forty years or five years from now. If you're vertically integrated it's less of a problem. Clearly you don't want to see capacity markets because you'd rather build your own; and earn a nice rate of return on that investment.

PJM's proposal is a step in the right direction because we know there's load growth, and we know it's going to be there four years from now. If a large player in the market contracts capacity forward, they're not stuck with it because somebody will pay them. If they lose the load, that capacity payment will get back to them because the model is structured properly. One criticism we've heard is that an obstacle in the market is this lack of long-term contracting.

Response: One problem is the defects in the spot market because if you've got a free hedge, why should you bother to contract? If you start pricing the scarcity in the spot market and people see that coming, that removes that problem. It may not be the only solution. I'm not opposed to long-term contracts in the look-ahead that PJM is planning. The problem is the asset specificity. Specifying this kind of generator at this location, and two of those is worth one-half

of this transmission, and forecasting ahead the demand side that is taken out from these programs. This is different from New Jersey and Maryland, where there are forward contracts for load, delivered to the load. Why can't customers hedge forward themselves? Why isn't there an active contract market? That's the intent here. I don't see why we have to require people to purchase generation capacity.

Comment: Those entities that you talked about are still counting on the regulatory hedge, in Maryland or New Jersey, because they're part of PJM, and PJM has a thousand dollar cap.

Response: There is an implicit assumption that prices or offers must be capped, and only a certain amount of volatility is allowable. And if you accept those as givens, then the PJM -- or the RPM -- model has merit. My fundamental question is must we accept those as givens? What is the cost? Once you go down that path, you have reinstituted or reconstituted a form of IRP. We've gone from transmission planning to transmission plus generation. If the spot price and volatility issues are fixed, that necessitates a different solution.

Response: The problem in long-term contracting is not retail access. In a liquid market, with creditworthy suppliers, that shouldn't matter. It is the free regulatory hedge. There is also uncertainty about transmission policy, and whether a new project will wipe out the value of your FTR. We are in a period of high prices, and customers aren't looking to go long at this point in the business cycle.

Question: The energy legislation just passed has mandatory reliability goals and it looks like NERC is going to be the ERO. NERC is drafting a resource adequacy assessment standard, which will require reliability councils to show how resource adequacy is going to be supplied. Will this help emphasize forward long-term contracts and move away from other mechanisms?

Comment: We don't know whether NERC will go to resource adequacy multi-year ahead or just year by year.

Response: It could go to a multi-year model. It is hard to understand how that might work because units may retire on a shorter time horizon. I don't know if you'll be committing a specific physical resource that far ahead. There are a lot of questions to answer.

Question: Our arguments have centered around a binary choice between capacity markets or energy-only markets. There's a third element to this. There are overt proposals in some states to rate base certain units. This includes MISO and PJM. How does that play in the energy-only model? What does that do to competitive markets? How do we factor that into this discussion so it's not just this binary choice?

Response: There is no reason that vertically integrated utilities wouldn't have to show that they're hedged. We're considering how it would work.

Response: We have wholesale market and retail jurisdictional questions. There are decisions made at state levels in retail and resource adequacy that are different from one state to the next. The key issue is designing the wholesale market. One of the advantages of the energy-only design is that the state issues are harmless. They can be painful to competitors, but that's not necessarily a problem.

Question: You don't think that has any impact on the marketplace?

Response: It has an impact on the market. It increases the cost for people that make mistakes. A well-designed energy market doesn't impose costs on other people. It imposes costs primarily on people who are making bad decisions.

Session Three. Transmission: A Market Participant or a Neutral Essential Market Enabler?

Two fundamentally divergent views of the role of the transmission business, other than dispatch and systems operations functions, have emerged in the restructuring debate:

- a. Transmission is not inherently a monopoly production. Transmission is as much a part of the market as generation and demand side management. Transmission services and the companies providing them are, in many cases, fully substitutable. Accordingly, mechanisms including proper market pricing need to be devised to assure that there are not only adequate facilities and services in place to assure reliable and competitive supply, but that those facilities and services are the most efficient means of meeting the need. The approach of putting all options in play is more likely to produce the most economically efficient result, rather than simply allowing incumbents to expand their own systems under traditionally regulated incentives.*
- b. Transmission is a natural monopoly whose strategic value for facilitating competitive energy markets, where the real value of competition is found, far exceeds the actual cost of the facilities and services themselves. Building transmission typically requires long lead times. Treating transmission as just another competitive service has a very real effect of reducing the likelihood of successfully expanding the grid. Given that transmission is only a small part of what the consumer ultimately pays for electricity, it makes sense to focus on setting the regulatory oversight framework for transmission providers rather than to worry about whether transmission providers should be integrated in the larger market.*

Speaker One.

A couple of months ago, National Grid released a transmission policy White Paper, "Transmission, a Critical Link." This panel emerged from some controversy over that paper. There's compelling evidence that restructuring in the U.S. has delivered some customer benefits. One study looked at the benefits of restructuring in the eastern interconnection and arrived at a \$15 billion figure. However, the lack of available transmission is stopping the full value of restructured markets from being realized. Transmission should be understood as a market facilitator, rather than part of the market.

In many markets there is insufficient transmission. These result in protected power markets, load pockets, restricted competition, and reliability concerns that lead to non-market solutions. In the Northeast there is ample capacity, despite issues with resource adequacy, capacity markets, LICAP markets, RPM and PJM. Virtually all the capacity concerns are localized. If one could assume a larger transmission system, then many resource adequacy debates would be unnecessary. Lack of transmission investment is undermining restructuring. We're getting competition but we're seeing more market power, less customer choice, and more regulator intervention.

Investment in the U.S. is significantly lower than many other countries that have restructured. This doesn't necessarily mean that investment in the U.S. is insufficient. However, if one compares congestion results between the U.S. and other countries, the results are compelling. For example, the increase in use of transmission loading relief procedures. U.S. markets that measure congestion see an increase, both PJM and New York have an upward trend. These RTOs were relying on the market to deliver transmission driven by LMP differentials.

Congestion rents may not be the best measure of congestion, I discuss them in order to present the trend. The long-term trend can only be shown using this fairly simplistic measure. Inadequate transmission has led to more protected markets

and an increase in concerns about market power. Market power concerns lead to a need for mitigation; and later on, to price caps. The price caps mean that generators aren't getting enough money to support their investment. We end up with generators threatening to close. This leads to reliability concerns and RMR contracts.

If we're going to have a deregulated commodity market, then generation needs to be there. It's a slippery slope if you start taking generators out of the market via RMR contracts. In New England that concern led to LICAP. There was an increasing number of RMR contracts, and FERC was worried that half of the generation in the market could end up on RMRs. Then there really isn't a market any more. Increasing RMRs in PJM have led to the RPM proposal. In New York, there aren't RMR contracts, but the New York PSC is looking at generation retirements because there is concern for reliability issues if generators start retiring.

These concerns lead to a lack of capital cost recovery in competitive markets. This results in capacity market designs designed to implement a semi-market semi-regulated process. Some of the capacity market proposals on the table are particularly expensive. This lack of transmission has different answers in different parts of the country. One of the key reasons is a misplaced perception that transmission is a market product, rather than an enabling infrastructure in which the market should operate.

There's good theoretical reasons for this. First, the AC transmission system is an interconnected network. It's hard to treat each component separately. Trying to treat discrete elements of that network as a market product is a problem. One example is PJM's latest RPM filing. They use locational capacity prices, and transmission is allowed to compete with generation in this locational capacity market. If there is capacity price differences between zones, they'll be able to capture those price differences, and transmission can compete. This is a problem for any typical AC transmission system upgrade. Most upgrades involve re-conducting existing lines to increase capacity. If I'm going to

upgrade my existing AC line, I'll bid the upgrade into the capacity market. For the first year, I'm paid for the upgrade. What happens year 2, 3, and 4 down the line? If market conditions change, and maybe I'm now out of the market, then what happens? I can't withdraw the transmission upgrade from the market. I can't put back the old conductor. It is a sunk investment, and an integral part of the AC transmission system. A class of transmission investments in the AC system don't make sense on a market basis because you can't switch them in and out like a market player could.

That doesn't apply to DC controllable upgrades. They can work on a market basis, but they are a specialized subset. Another problem is lumpiness of transmission. If you combine these two things, the majority of efficient transmission isn't working on a market basis.

Where we've adopted policies that rely on market upgrades to get transmission built, it isn't built and we've ended up with increasing congestion. We need something more than that. That's why PJM has developed their economic planning process. It is an important step; a way of actually getting transmission built.

There is a role for merchant transmission. It will tend to be niche opportunities, typically DC interconnectors between markets such as Neptune, Seabreeze, or the Cross Sound Cable. However, relying on such merchant projects to get the nation's infrastructure built is naive.

Another concern may be too many transmission owners and too much fragmentation in the industry. A lack of independence of transmission from generation is also a problem. Lack of financial incentives is an issue, as well. There's quite a connection between some of these issues.

A concern about regulated transmission is whether it inhibits innovative transmission solutions. However, an independent transmission company with a sufficiently large footprint and performance-based rates can be incentivized to innovate. The situation in the U.K. demonstrates that. If we see transmission

as the backbone of the market, then it enables trade. It also helps with fuel diversity, gas dependence, renewables, reducing regulated intervention, and a good deal for the customer.

The solution has several facets. First, robust regional transmission planning processes are needed. Central planning doesn't sound compatible with markets, but a principled bright line between transmission versus the generation and demand side commodity market, can be done on a market basis. Some argue that as soon as you allow central planning for transmission, generation could be an alternative for transmission, so include that in central planning. Then we are completely re-regulated. That's an issue, but there are sufficient differences between transmission and generation such that you can draw that bright line. The alternative is the pure market solution for everything: generation, transmission and demand side auctions. This has failed because lack of transmission is making the markets fail.

Speaker Two.

Independent transmission companies have FERC as sole regulator. When they buy assets, state commissions lose control of financial terms and conditions. In integrated companies, they retain them. However, the independents still go to the states for their permission to build. They are still present in many state commissions, not only ones where they operate, but also adjacent states because transmission is expansive. As a consequence, Transcos have to let people know what they're doing and where they're doing it. They essentially consolidate ownership of the transmission system.

The independents have to invest tremendous amounts of capital into infrastructure. They do it with new and existing rights of way. They have to convince investors and permitting agencies that it's a good idea. There is a formula rate every year. Customers, who can represent themselves at FERC, generally have 100 percent support for what in fact is a major rate increase every year. Rates are going up but this is not a problem if they are building in response to

customer request. State commissions can be supportive as well. This is a reversal from past times when parts of the grid were not very strong. When open access arrived, the capacity to be able to move load, and generation to load, disappeared. Moving from an inadequate to an adequate system required considerable effort.

Competition is at the core of planning. Do we compete against alternative ways of meeting load and the needs of the system? If we overcome an aversion to central planning it becomes clear that even the most competitive are asking the RTO to do planning and transmission. A system that serves everybody has to be centrally planned. When transmission is the sole business, everybody looks like a customer. Planning is an open process in which you are continuously gathering the need of your customers. The customer is not only the person trading in the market and buying transmission rights. Transmission provides a public necessity, the access to energy that supports the livelihood of people and the development of society – the customer base is very broad. Transmission is an implementer of public policy. Just like politics, all transmission is local. Either we convince local people that there is a significant need for them, or you will never build it.

We have to implement and account for operational performance, design performance, new load, economic development areas, and new generation. Often, the transmission company doesn't know what the future holds. New generation is very uncertain because the generators like to keep the decision to the last minute. Transmission companies blend all these issues and put them in the public forum when they consider projects. They look at projects ten years down the line because a transmission line of any length takes ten years to build.

A transmission system is one of the necessities of economic development. If state developers attract a new car factory, they come to a transmission company and ask to connect it. They response is, 'great, we'll see you in ten years.' The car factory will go somewhere that has transmission everywhere. The market price

does not respond to the signals required to build transmission. The most expensive transmission line is the one you don't have when you need it. It is cheap compared to not having it.

One solution is to force highway departments to allow transmission lines. This acknowledges that it is part of the overall land development. Transmission planning has to aggregate many benefits in one project. Building a transmission project only for the trading of energy between two points is a mistake if it ignores other needs. It's intrusive in people's lives. I have just defined a utility. I have just defined a monopoly. Market price signals, DSM, and generation do not address all needs. There are other needs that people require transmission to build.

Furthermore, ownership in the system is fractured. If a transmission company can aggregate from 26 companies into one, the benefits are enormous in operations, maintenance, construction, and planning. Further intentional fracturing of the system brings no benefit that I can measure.

Utility companies do have an incentive to save money as much as possible. Some have ended AFUDC, Allowance for Funds Used During Construction. In a three billion program, 500 million dollars in rates can be saved. Incidentally, this can increase cash flow, and reduce borrowing needs. Utilities must cut costs to be effective and successful. This requires the collaboration and the credibility of many people for the long term, they are not here for just one hit. The cost of failure in the utility business is widespread. They are indemnified by state and federal law from the financial consequences of failures, but not from regulatory consequences. Furthermore, the financial liability protection may not last much longer.

So who pays? Those who benefit. When you think of the reasons we build, then you realize the benefits are widespread. Traditionally, we have always been able to allocate the cost among the load that is benefiting. That is why the concept of license plate was proposed a long time ago. License plate recognized the fact that

some areas need less transmission than others. You can allocate, but this is nothing but a price zone. We can allocate cost between license plates, and you would do in the benefit. If you plan on benefits, you can identify who benefits as a consequence, and identify who pays.

There are always subsidies. It is public policy that in this country, everybody will have access to electricity. As a consequence, you cannot allocate costs in a refined manner because some people expect to get a benefit they don't pay for. If so, why don't they use taxes? Explain that to a legislature and see how they like it. The answer is no, it's going to be in the rates. You cannot slice the salami any further. Subsidies are here to stay because it's public policy.

Any failure to serve is a failure of the system, even if it is a voluntary shutdown. That is not economic. If we have to change the criteria of reliability we must explain the consequences. We like to have a level of reliability, and then we complain about what it takes to pay. Except once the rate is stabilized, we don't think about it anymore. So that's the end of it. Reliable, economic, clean, and safe are the requirements. Does society have to look at reliability? Only the highest reliability level is acceptable in Canada and U.S. The public will hold politicians, regulators, and utilities accountable for that. Can we change it? I don't know.

Speaker Three.

Someone told me that the perfect transmission system would be a copper plate in the sky but I don't think we want to go there. I'm somewhat suspicious of central planning and this sets me on a humble quest for a market mechanism for transmission. This still begs the question of whether transmission is a market enabler or a market participant. However, we clearly haven't built enough transmission over the last 25 years in this country.

The benefits of a robust transmission system are well-known. It lends itself to reliability, eliminates load pockets, and allows access to

diverse generation sources. Access to wind power and renewables without a robust transmission system would be difficult. However, you can go too far. In the Soviet Block, they crisscrossed their countries with 400 KV transmission lines and none of it is going to be used for decades, if ever. You can waste capital by overbuilding transmission.

Still, we haven't built enough, and the problems of siting, permitting, building, and financing transmission are onerous. Almost everything else gets precedence over transmission in the resource mix. Instead of building a transmission line, a gas line may be built, and a combined cycle unit put close to load. If the regulatory environment was better, one would build a transmission line. This brings us to a quest for a successful market design which brings transmission into the fold of the other resource options, such as generation and DSM. This design would balance commercial incentives, reliability rules, and network interactions. It would be transparent, non-discriminatory, and not overly complex.

The FERC NOPR 2000, and the SMD, always left out how transmission was going to be planned and built. It was always up to the RTOs, or someone else, to figure out in the next three to four years. Thus, transmission is the most onerous of the options in the resource mix. It distorts the market when you do not have one leg of the stool with regulatory clarity. A balanced regulatory setup, which has transmission in the balance with DSM and generation is the best long-term way to build the infrastructure.

Consider the role of transmission in a system with transmission constraints. The transmission defines the market. The transmission congestion causes the difference in LMPs between regions and between nodes. So, transmission is almost the market-maker.

An opposing view argues that regional planning should have generation, load, and DSM on a level playing field. Socializing one of those elements leads you to a slippery slope because it

leads to preferential treatment. You need market mechanisms for all three for a successful market to work. Transmission is one of the options to reduce LMPs. It acts like a market participant.

The regulatory uncertainty over the role of transmission and how it's built distorts the market. Is transmission special? Is it fundamentally different from generation and DSM? Some characterizations argue that the ports do not compete with the local factories. The transmission system is like a transportation hub, and lets generation compete freely. This is a valid analogy. The cost of transportation hubs is reflected in the price of goods sold. There is no sharing these infrastructure additions between cities. There is no complex process for looking at shipping lines and congestion, and port congestion, and so on. If you can import goods from overseas, and if the cost of the goods overseas plus transportation cost is lower than what you can produce locally, you compete in that market, and the local goods are at a disadvantage. One of the easiest ways to kill local production is to subsidize or socialize the transportation infrastructure. There is a better way. You can make a case for making transmission a public good, and you overbuild it. However, prudent regulatory policy requires a market mechanism.

Let's consider some other observations concerning the transmission market. Short-term congestion rights do not have sufficient duration or enough congestion to justify building new transmission. You cannot have a bankable transmission project based on short-term congestion rights. Long-term congestion rights make sense if you want to make financial transmission projects bankable. Another issue is cost. My colleagues have talked about innovation and transmission. Cost of service models do not promote innovation. If you consider the railroads, there have not been any new railroad lines being built, but there has been tremendous application of IT. The throughput on the railroad infrastructure has been increased by better use of IT and other technologies. For such technological innovations to hold with transmission, the rewards of increasing capacity

should be tied to the value of that capacity, and not on the cost of service method where you simply pay for the hardware you put in.

The use of merchant or independent transmission developers also needs to be considered. There have been a few successful DC products built by independents, and at least one AC product. In a viable market-driven transmission market, there has to be a mechanism to allow increased independence to build transmission corridors. This should not be the purview of the incumbent utility.

The RTO's role again should be to keep the lights on; the coordination and implementation of reliability. When RTOs get into central planning and rate making, it distorts the market, and heads down the slippery slope. It starts with transmission, and then you get into generation and DSM, and soon, you are in an IRP regime.

This leads us back to the market mechanisms. What is a load to do to reduce its LMP? The transmission mechanism will work if you have long-term transmission rights. If an independent transmission company proposes a major transmission project, they could get long-term transmission rights from the RTO. The most obvious buyers of those rights would be the load-serving entities, who would then have them for the long term. If there are short-term free rider problems, and other people go and use the line, the LSEs would still be financially hedged because they would collect the rentals. The LSEs would have that hedge if they have long-term transmission rights. This is one way to put transmission on a level playing field with demand side management and generation.

We can do better than saying that transmission is a public good, and just go overbuild it. There has not been enough of it built, and you must have regulatory clarity so it can be built on the same level playing field as generation and DSM options.

Clarifying Question: What does long-term mean in your mind?

Response: This would be 15 to 30 years.

Speaker Four.

There is a general consensus among utilities that we need to build transmission, and to upgrade the transmission lines. Along with that comes reluctance to put in the effort to get those lines built. We've got to figure out a way to catch up quickly, whether it's markets or monopoly. Overbuilt transmission is a problem that I'd love to have right now when I consider the state of transmission in the United States.

We can have a market and competition to encourage the building of lines, or a monopoly service that uses regulation to get transmission built, which then enables the larger competition of generation. Let's consider the market side. In 1996 some utility people felt they could get returns of 20 to 25 percent on investments of money. Transmission had an investment return of 10 percent. Develop a company to sell transmission and get it out of the utility. Remove the worries of outages and tripping off customers, and all these bad things that happen when you operate a system. At that time, independent transmission companies meant merchant companies (we've morphed a long way from that definition).

What were the economics of this? First, consider gas pipelines and what happened there. There was pipe on pipe competition, and it worked well. Next, the telecommunications industry deregulated when Congress and the politicians mandated competition. Interestingly, the courts just found that FCC was not proper in taking action to open those lines; that they shouldn't have taken those rights away from the telecommunications people. What did that really give us? Reduced costs? My bill has gone from nine dollars to nineteen dollars for basic service. However, it did give us innovation. That was driven home to me as I was out watering my yard one time. I lived in an area which had a lot of creeks and trees in it. One summer afternoon, these kids with water guns are playing war games in the creek and they're all on cell phones coordinating their attacks. If we could get that kind of innovation started in utilities, it would be great. I was in the military when you fired

artillery shells as signaling devices because radio communications were so bad.

The next thing to consider was how to pay for it. If one could get around an incumbent utility and get to inexpensive power nearby, that would make money. Some lines were built that allowed that kind of activity, and were doing extremely well. In some cases, the total cost was seven percent. In some utilities however, transportation runs 17 to 20 percent of their product. If independent transmission companies could raise the price to the incumbent by ten percent for a transmission line, it would make a small fortune. However, people then started to realize what it meant to put that kind of company together; what it meant to convince a regulator that they ought to just turn you loose and let you go out there; what it meant to finance a fight of ten years for right of way.

I like the new ITC program that we have today because it focuses companies on transmission, and that's valuable. We know there are regional issues: the West is more focused on voltage stability, and long lines. The East more on capacity; a lot of lines are overloaded because of high densities. However, I used to feel they were basically the same. I never accepted that electricity was different, and carried that philosophy into the telecommunications and gas business. Since then I have come to the conclusion that electricity is different. There are the basic differences. You can't store it; whenever you distribute it on a physical system, the power goes wherever it wants; you aren't able to direct it without DC lines. I began to weaken on the market side. I realized the states had tremendous opposition to the market conception and to FERC's regulatory rule that would open up transmission. It is almost an impossibility to convince them to give up whatever control they had on transmission.

I started moving from the Camp A, the market perspective, to what I call the Camp B, which is the enabler side of it. The existing regulatory framework and property rights are going to make it extremely difficult to move to a market arena. FERC 888 ended the idea of charging an

extra 10 percent to get power from one point to another because open access was clearly mandated, and you can't just charge whatever you would like.

The physical constraints on the lines are complex. We can do economic studies and engineering studies to determine flows; we can look at locational marginal pricing. In the end, people don't accept those; they are so variable. It is difficult to come up with an economic model that plugs all these variables in, and then justifies this line. Guess what? You'd plug all the economic variables in there, and somebody would come in and say, 'well, I'll put distributive generation here, and you don't need that.' Suddenly, you can't justify it. Time differences are horrendous. Generation is being built in three years; line design is ten years. How can we compare those two? You get into a debate that for the regulators makes no sense. Finally, transmission isn't an economic decision so much as it is an environmental decision. You have to convince the regulator and the consumer that it is a benefit; a necessity.

The other thing that drives me to some type of regulatory framework is the migration of generation from load centers to other areas. If you look at the East Coast, a lot of these generating units are looking at long haul: coal out of North Dakota or Kentucky, for the East Coast. It's not going to be real popular for the people between Kentucky and New Jersey to have lines run there. We have to have some kind of regulatory model. So far, PJM's gone to their central planning system that works well.

The last hurdle is financing the lines. I have seen few projects that can justify, and get, financing solely as a market participant. The contracts require knowing where the power flows. You can't do point to point contracts because it impacts other people.

As much as I would love to say we're going to have merchant lines, in the short term, we're going to have to get the system built in some more demanding ways. Quite honestly, the cost of transmission dollar-wise is very small. We have to get the environmental concerns taken

care of so that we can get them built. If we get to the point where we have sufficient transmission, then let's try some of these other things. I worry that we haven't paid enough attention to the blackout that we saw in 2003. We'll probably see another one if we don't get off the dime and start building transmission lines.

Discussion.

Question: I'd like the panel to comment on this issue of building "economic transmission," meaning transmission not absolutely required to keep the lights on, and how to recover those costs from the appropriate people. Absent a national policy that says this is a social good for everyone, stakeholders will continue to ask why I should I pay for this, or why should my customers pay for this. So please address the cost recovery, and the cost shifting or non-shifting issue.

Response: There's two parts to your question. One is about cost recovery, and ensuring that if we build transmission, it has ultimate customer rights, which is an issue for state/federal jurisdiction. There's also the cost allocation issues: who pays if transmission is regulated. We are seeing ways of addressing these, particularly in the organized market areas where the regional planning entity is identifying that transmission is needed. Normally, you have some sort of ISO/RTO tariff to address some of the cost recovery issues. State commissions are a bit more willing to pass through a tariff when it's clearly for the good of the region.

A regional perspective is necessary if you are going to build regulated transmission, so the beneficiaries pay. The issue is identifying the beneficiaries; they are a moving entity because beneficiaries change over time. Running a study on a particular day and saying who the beneficiaries are today doesn't necessarily tell you who is going to be the beneficiary of the project. You have to be realistic, you're not going to get precisely the right beneficiaries. You need some sort of broadly reasonable "rough justice" allocation of beneficiaries. The RTO or ISO is probably in the best position to

do that. PJM is doing that reasonably successfully. However, I'd like them to write their methodology down, rather than just making it up case by case. New York is making some progress on beneficiary's payments as part of the regional planning process.

Response: I agree with what you said, but only partly. The planning process is based on identifying the beneficiaries. Not the marginal beneficiaries, but the main beneficiaries. The companies that serve across states have the best chance of getting it done because transmission becomes a very personal thing to the regulator. They are the local company wherever they go. There is no regional authority that we have found that is legally binding. You must work every jurisdiction so that you can bring benefits. Identifying local needs is the basis by which you justify construction of a line, even though somebody 80 miles in either direction is going to get a benefit.

Response: Well, load-serving entities could contract for long-term transmission rights. Currently they can only see forward three to five years. If there were long-term transmission rights, and you could match the generation with the load-serving entities, that would be a mechanism to have people say 'I want to buy and own these rights over ten years.' That could make some projects finance-able.

Question: We know it takes time to put in transmission lines. We need some kind of planning. The definitions of adequate planning are obviously different on the panel. There is a problem in the planning process with the ISOs and FERC. Let's consider an example from New Jersey. A large generator announced they're going to shut down several generation facilities in the state for economic reasons. Some of them turned out to be reliability must run. Now PJM is scampering to find out where the heck they're going to put transmission lines into northern New Jersey, where there's people everywhere, and if there aren't people, there's beautiful environment. Obviously, there are significant problems in northern New Jersey.

I am told that, because of FERC requirements, PJM cannot require any more notice of generators when they're going to shut down their generation, even though it substantially impacts a large body of people. There's something wrong with this system. How would you recommend that it be changed, who changes it, and how do we do it?

Response: This is a big problem in organized markets. Announced generator retirements are leading to reliability concerns and RMR contracts. I would like to see reasonable notice of generator retirements. Although there may be some legal restrictions, in the capacity market you can have some link between the payment for capacity and some sort of reasonably long-term commitment by the generator. In the PJM/RPM construct, a three or four-year ahead commitment for one year is being discussed. The planning process needs to deal with uncertainty in generation. It's not that hard to work out which generators may close, there are top candidates.

A reasonable planning process shouldn't be just running a base case. It needs to be looking at uncertainty. It needs to be looking at the different scenarios that consider transmission planning and other solutions. Aggressive proactive regional planning will help get transmission built to make the system more robust. A solid commitment from generators as part of the capacity market will also help.

Response: There is a strong role for the state regulator in this because state energy policy is an important factor. It is part of planning to look at contingencies. For some utilities it's important to stay on top of what is happening to old coal. You don't even dream of closing those plants until you are done with transmission work. In some areas you may have several old, uneconomic plants that require significant environmental work. It doesn't take a magician to know that there is great pressure to shut them down. Yet, congestion would require curtailing load until transmission is built. With a multi-year transmission construction plan don't even

dream of shutting down those units until the transmission is done.

Question: Is there any legal authority over the generators?

Response: A state ought to be able to request information. Often, they require privacy because when you shut down a power plant, it's a critical event. For instance, consider power plants in downtown areas; don't count on rebuilding them on the same site. They are efficient transmission sources because they're close to the load. Replacing them is less efficient from the perspective of using transmission to provide load. Sometimes a customer will let a transmission company know in private because it's not good for them to do so publicly.

Nuclear power plants provide more notice. They are tremendous sources in the network. The question is, are they going to be re-licensed or can anything else be built on the same site. In these cases it can be 10-20 more years to find an alternative site to support the system.

Question: I'm not talking about that, I'm talking about six months' notice.

Response: Sometimes it's a merchant plant, and they are just going to shut it down and get out. When it is a load-serving entity, they bear a responsibility in the state and cannot get out of that. Then, the dialogue is far more logical.

Comment: There are some temporary stop-gap payments. However, I haven't heard any elegant market solutions for this dilemma because stop-gap payments or invasive planning mechanisms do not allow low barriers to exit that you'd like to see in a market.

Question: I've been told that FERC will not allow any lengthy time period of notice. Generation should be able to get in and out when they want to, even if it's causing a serious problem such as congestion. They will not let LSEs or RTOs require a three or four-year notice so that you can plan adequate transmission coming in.

Let's consider the load-serving entity. You can always have FERC or the RTO try to keep generation through stop-gap measures. However, if you put the onus on the load-serving entity, they are there for the long term. They're the provider of last resort, and they should have a plan to serve energy and capacity, and they should contract for it. The load-serving entity essentially serves energy and reliability. They should be the ones thinking these plans could go away, and these transmissions have not been built. It would be a market fix if you put the onus on the LSE responsible for providing the energy and a required degree of reliability. That would be a solution, but it is not in place.

Response: One of the myths that bothers me is that we have to keep this information confidential. You have to have a planning process that looks out ten years. We can all run around and say we don't know whether that plant is going to shut down. In fact, we all know it's going to shut down because it's 92 years old, and it's off 90 percent of the time. It's pretty obvious. That ought to be in our plans. You've got to plan for those contingencies. For instance, in New Jersey there are a lot of those old plants there, and they should have seen that coming five or ten years ago. If you have reliability must run, then there are time limits and a contract. The regional planner knows what that unit is going to do. That's got to be in the public domain so people can make decisions.

I tend to look at the high voltage transmission system like the freeway system. How does one convince people in Idaho, with Montana and Wyoming coal to its east, and California, Washington and Oregon to its west with their load, and 500 lines crisscrossing the state that never slow down or drop a stinger into anything; how am I going to convince those people that that line is absolutely necessary? You've got to give authority to somebody. They can say that it's for the betterment of the country to have a line built. That hurts me because I'm a states-right believer.

Question: I want to focus on something that several of the panel members said in order to try

to redirect it slightly. One set of arguments concerns lumpiness; and another problem is benefits that are spread around. One conclusion is that we can't rely on merchant transmission investments, and therefore we shouldn't have any. This is a non-sequitur. Another series of arguments concerns the choice between a bunch of fragmented little tiny merchant companies, or a large multi-state independent transmission operation. This strikes me as a non-sequitur.

Instead, the issue is the bright line question posed earlier. One argument says that it's easy to draw a principled bright line between transmission and everything else. The comments of the subsequent panelists argued no, it's not. You'll get distributed generation arguments, or stakeholders will say we should do DSM, it's not justified. It just doesn't make sense to say it's transmission and everything else. There are some characteristics of transmission investments that are on one side of the line and others on the other side.

The same arguments apply to a big generator in a load pocket. When it retires, then it goes away. That might be on the transmission side of the line. This argument doesn't apply to DSM because it is inherently small, and distributed generation is small by definition. They don't have lumpiness. It creates all kinds of other collateral difficulties in the rest of the market design if you don't draw that line, not horizontally between transmission and everything else, but vertically, to separate different kinds of investments. That's the distinction that I see missing here. The Argentinean model draws the line in a better way. It's much better than "transmission and everything else." If we adopted something like that, it would be a lot easier at meetings where people say do DSM or distributed generation, and also for dealing with merchant transmission, and long-term FTRs. I think the framing of the problem, which is it's either all of one or all of the other, as opposed to the hybrid model where you draw the line, is misleading the discussion.

Response: There are benefits in having a single entity who considers the whole system. These

approaches will not happen. In most states, the regulatory process will show that you're not taking into account the everyone's needs, and that is a significant difficulty.

Comment: Could you clarify the Argentinean model?

Question/Response: The critical features are that there is a mechanism for making decisions about these proposals which have widely-dispersed benefits. You identify who the beneficiaries are. There is a process for making the decision to go forward on those things. If you go forward, you make people pay who are the beneficiaries. You use the power of regulation to make them pay. There is a process, a rule, and set of voting procedures and criteria which allow those things to go forward.

Second, consider proposals that are not particularly lumpy and don't have these kinds of problems, and are attractive economically. These should occur but the market is not doing it. If the market isn't doing that kind of a project, the rules should state the central planner is not going to do it, even though they think it's a good idea. If you don't have a set of rules like that, then essentially we're going to do whatever the central planner wants, because they think it's a good idea, and have the regulatory power to make people pay. There needs to be some way to make a distinction between those projects, and then defer to the market if they don't pass the test, or you're not going to have a market.

Comment: It's knowing how to leave enough space to have a market solution come forward?

Question/Response: Especially to have merchant transmission come forward. Even if there wasn't very much, it's not the objective. The objective is to be able to have a principled way to say no to subsidizing everything.

Response: I agree with you. You can't say all transmission won't work as a market. Some transmission products work on a market basis. However, it's more than lumpiness. The AC common nature of the system is a bigger

problem. Let's consider merchant transmission and long-term TCCs as the answer.

When you build an a thousand megawatt line upgrade on an AC system, you don't necessarily get a thousand megawatts of upgrade benefit. The benefit depends on what else is going on in the system, the power flows on the parallel lines, the generation, and the demands on the system. Merchant constructions can upgrade but the thousand megawatts is a short-term approximation. In five years' time, it may only be 500 or 1,500; who knows. If you give them long-term TCCs, you have not only a price risk, but also a big volume risk. The merchant has to deal with it, which is a problem with financing, or the incumbent utility and their customers end up paying for it.

The vast majority of transmission can't be market-based. We should be focusing on getting transmission built. Otherwise, we're going to end up with the current under-invested transmission system continuing. However, the debate is improved by talking about the Argentinean model. It has a central authority, an ISO evaluating projects there are beneficial. Projects are only proposed when a market participant proposes them. However, most stakeholder processes have that sort of element. The model identifies beneficiaries, although it is more complicated in the Argentinean case where they have a radial system. The real difference is that a certain number of market participants must agree to fund it. In the model I propose stakeholders have their say, but ultimately a regulatory body decides. It depends on whether you believe that most AC transmission upgrades are going to suffer market failure as well as lumpy transmission upgrades. That's why a comprehensive transmission planning process is appropriate.

Question/Comment: The Argentinean system is more different than you're implying. The historical origin of transmission congestion contracts and long-term financial transmission rights was to solve the volume risk problem that you identified. This problem goes away under the system, as in PJM or New York. The price

risk problem is there, but that's also true with a generator that you build any place. It might be in northern New Jersey, and gas prices are expensive, and it's not worth so much any more. That's life.

Question: Could the panel comment on the ideal role for regional state committees as we move forward?

Response: It is important for state commissions to be engaged with each other. It was not happening before. It does not undermine authority within a state, but gives access to information on adjacent issues that are likely to come home to roost. It is a struggle to explain to each group of regulators, state by state, the same issue over and over again. Before the reorganization there was nobody actually up to speed on specific issues. Regulators, each with their own authority and law, come to a realization and common knowledge of options under discussion.

Response: A key issue is asking the right questions and paying attention to market signals. A recent report in California said market signals were low, we ought to be giving generators more money to stay in business. If they are low, ask questions about what it is telling you. We're trying to get to a model that says let the market find the cost, but still acknowledges reliability as the bedrock platform. All of a sudden, a re-qualified 3,500 megawatts of capacity was coming online in California. The market prices were low because generators were anticipating the re-qualified power. There's often more to the story. Look at the bigger story, and listen to the larger set of issues.

Question: You suggested that longer-term TCCs or FTRs would allow for a more liquid market. In order for a load-serving entity to purchase a significant long-term transmission right, it would have to go through a long planning process. They would have to interact with the regulators. The builder would have to understand the effects on the rest of the system from the construction. This sounds like the same planning process. I don't see the difference

between this proposal versus a competitive acquisition after everyone's made the decision of what's to be built.

Response: Let me give you an example. Some time ago, LIPA, which is the load-serving entity for Long Island, looked at the resource mix. They had generation, DSM, renewables, and transmission options. The Cross-Sound Cable was constructed in 2002, and put in service two years later. They agreed to a long-term contract to build a cable. Last year, they did an analysis again and put a RFP out for getting more energy into Long Island. They chose another cable, this time from New Jersey, not from Connecticut.

They are peculiar because they are a government entity so they can structure a long-term deal. That's why I'm saying publicly-held load-serving entities should have an onus to serve their load. But they are not allowed to have long-term contracts for transmission. If they had the onus to supply energy and reliability, and were allowed to structure a transmission option as a part of that, they could really make that trade-off between generation and transmission and DSM, and not have that amount of regulatory intervention.

Question: Yes, but Long Island may be different because it's a public utility and it doesn't have the same kind of regulation.

Response: The LSE does have to go through the RTO and the regional planning process. You can't do away with the regional planning process. But don't have the regional planning process choose the options, and then have the regulators go in and jump in and do damage control when things go wrong. If you put the onus on people who have the responsibility to serve load, you might get a market-driven planning process. This doesn't take away the RTO's role of coordinating the region.

Response: There's an extra point. In New York, we have retail competition. How does Long Island Power Authority know that in five or ten years' time, it's going to have any customers? I don't think this model works where we have

retail competition. If the LSE does it all, there are some real issues. It's throwing away a lot of the market, actually.

Response: Any business makes that decision. Ford can build a huge factory, and it might not have any customers to buy Ford cars. If the LSE is a public entity, the shareholders take the hit.

Response: I don't see any investor-owned utility with retail competition doing a 10-year or 15-year transmission contract to build transmission. There are ways of getting merchant transmission as a DC under sea project we've talked about. The two models we've discussed are specialized examples.

Comment: I'm not sure that that's the only case that we've got in the industry. There are other areas considering merchant. It is selling forward. There's at least some indication that even if you have retail competition, you could have some forward merchant contracting.

Question: One distinction I see is that if you consider generation, what's the decision process? Somebody has to convince the bank to loan them money. They've got to convince siting authorities to put the generation at a certain place, and they have to jump through some other hoops if they're a merchant generator. In general, a transmission project, especially on the AC system, has a different process. You have to convince the regulators to allow you to charge customers for it over the next 30 or 40 years.

Furthermore, the NOI on Order 888 will be released soon. It has 22 different sets of questions; concerning pricing, joint planning, expansion obligations under rollover rights. Some of these questions about joint planning and joint ownership will have a strong effect on transmission building debate. If firm customers, the munis, and the coops get more involved in the planning function and in ownership, what does that mean for the current discussion?

Response: For some companies, this is happening right now, so actually, it would not mean much. The participation of the customer in

the planning is an essential element. It's guaranteed, you will not build transmission if your customers don't want it. If you have only one customer who wants it, or a group of customers that want it, that's an issue for the Commission to decide.

Question: The Energy Policy Act of 1992, as implemented through Order 888, made a huge mistake in that it de-integrated the power system from the grid, and generation siting. Huge mistakes were made. As a matter of fact, we assessed 195 gas-fired generation requests to connect 85,000 megawatts of generation to a 35,000 mile transmission system. Actually, the DOE and I disagree on the term. They say we *de-integrated* planning of generation and transmission; I say we *disintegrated* planning of generation and transmission. In any case, this led to the largest investment in generation in the history. Generation ran to the fuel supply, primarily to the site. It resulted in the lowest investment in transmission (in terms of percent of revenue) since 1933. We have skipped about a decade of building the adequate transmission.

Following the blackout of 1965, we realized we cannot do this, and established NERC, and built transmission. We increased investment by a factor of five in a short period of time. Following the blackout of 2003, the RAS report showed the number of miles of VHV planned had dropped off the next year, according to NERC. The societal cost of not having transmission is three billion dollars per year of congestion in New York and PJM. Six billion dollars at least, maybe ten on the blackout. EPRI says we have increased outage costs from 25 million to 120 million since 1996. DOE has stated the cost of outages across the nation is close to 80 billion dollars. How much longer are we going to debate this issue, and how much time do we have to fix the transmission problem? If we take ten years, we will shut down a ten trillion dollar economy.

Comment: How do you eat an elephant? One bite at a time.

Comment: One mile at a time.

Response: This is where the states and utilities have a local need and responsibility. It has to be justified locally by the people who pay for it. We're moving in the right direction. For instance, the folks in Minnesota have already cranked up about two billion dollars of planning costs. Folks in Georgia also have a significant construction plan. There are improvements. Right now, seven years is the current planning time, down three years from a decade ago.

Response: The lack of transmission investment is a big concern. Are you saying that separation of generation and transmission planning is the root cause? In a competitive commodity market, generation isn't planned. A transmission planning process that is reactive to market needs is essential. It's a different planning system. We are starting to develop more robust planning processes in some market regions. In other regions, we are only just getting started.

Question: There are multiple levels of central planning, of regional planning, and multiple distinctions. PJM has gone far in trying to develop a process that considers the broad needs of the region, and tries to do a fair analytical job; to facilitate the right kinds of decision. Central planning means imposing a set of decisions from the top, as opposed to a process in which objective analytical work can be done that consider the whole country, or a region of the country. A key issue is who makes the decisions to determine the distinctions between the kinds of investments and how they ought to be treated. PJM's process tries to look at all of the kinds of investments and put together the data that permits the market to come forward. It provides opportunity for the market to address the needs that are identified: economic and reliability. Does the panel see a process that's more sophisticated, and which will enable more comprehensive analytical work for regulators, state and federal? It should support market solutions where possible, and ultimately, backstop solutions if they need to be imposed.

Response: There are ways the PJM process and regional planning process can be improved. They need to identify what benefits transmission

might give you, and then have a vigorous analysis. They analyze the location of commodity benefits of transmission upgrades, as well as reliability quite well. They don't assess the locational capacity benefits of transmission upgrades as well. There are further issues for renewables, which need plenty of transmission. In Southern California they're proposing transmission upgrades just for renewals. Furthermore, if you build transmission, it creates economic opportunities. We've talked about big transmission projects which could allow coal-fire generation to get to load. Transmission can release that opportunity. This is an evolving process.

Response: There will not be a single planning process that is best for the whole country. Planning processes adjust to the region. MISO uses a layer coordinated planning process which allows collaboration across the boundaries of utilities. However, the decision of what gets built will continue to be on a state by state basis. I doubt any states would allow the Commission to delegate planning to MISO. Thus, the state regulators must be engaged in the discussion ahead of time. By the time a project comes to a Commission, there's somebody in the staff who has a keen knowledge of the priorities involved.

Comment: I deal with things like Order 2003 and 2004, and state IRP requirements. It fills me with despair when I think about how anything is ever going to get built. One concern is that we're not looking at the regulatory framework. There is a disconnect between the states and the feds on all of this. States aren't trying to drive a wedge between generation and transmission the way FERC is. Most states are looking at things on a system basis. They have state RFPs and IRP requirements to take this into account.

At the same time, FERC's Order 2004 prevents transmission and merchant functions from being able to talk to each other in any kind of logical way. Their Order 2003 uses queue requirements to prioritize rather than a rational process. Their tariff requirements are somewhat disjointed. Even if a utility had the wherewithal to actually build anything, it cannot be assured that it will

get the benefit of a line that it builds under open access requirements.

In this context the planning model, from a practical regulatory standpoint, is the most workable. However, these models call a lot of economic balls and strikes that affect customers. Alternately, I like some of the merchant model. However, it seems difficult to fit within state RFP requirements. Even if it did, how do you get FERC pricing for a line that would work? This discussion is divorced from the practical realities of transmission implementation. EPAct [Energy Policy Act of 2005] addresses this a bit but unless the whole country is declared a critical corridor, it won't do much. How are we going to construct anything now, other than minor patches to the system?

Response: We are doing it. It can be done. The process of planning is to bring light to client needs, and discuss it with everybody. If you do it ahead of time, it gives you a chance to take care of the problems. In proceedings, as long as everybody who is engaged has a chance to represent themselves, and there's enough time for evidence and information, then you have to be satisfied that the process is acceptable. It requires that regulators and utilities play their role. This includes industrials, other users of energy, and the marketers.

Comment: I don't question that some transmission investment is needed, but I also do not ascribe to the assumption that this is a large issue. If it is, we should be spending just as much time on investment in distributed generation and DSM. Bang for the buck, these can do a lot more for reliability and economics than transmission in many cases.

The other thing being discussed is that the lack of transmission build-up is somehow related to reliability issues, which I believe is a smokescreen. The 2003 blackout had nothing to do with insufficient transmission. In fact, most outages are not transmission-caused or related to a lack of transmission. Witness the California wire-cutting a week ago, or Hurricane Katrina.

As far as economic upgrades go, look to the PJM process. It provides a mechanism with an unhedgeable congestion test. Very little transmission will prove itself economic to that. We shouldn't be running off to build out the transmission system because it feels good.

Question: I was going to say much of what was just said. I am troubled by the premise that insufficient transmission has been built. What's been emphasized in the SMD debate is the regional differences. It may be true on a national level in an aggregate basis, but it may be

different from region to region as to what's actually taking place.

Response: I think the system is lacking. The transmission operation is now less reliable. Operators are addressing events every day that were rare ten years ago. It's probabilistic. The more the operator has to take action, the closer you are to the edge. Reliability is lower, there's no doubt about it. The regional differences are also important though. While some areas have enough transmission, there is not enough in the areas I deal with.