Harvard Electricity Policy Group
Twenty-Sixth Plenary Session
The Park Hyatt
Washington, DC
September 20-21, 2001

RAPPORTEUR'S SUMMARY*

Morning Session: A Federal System Struggles to Restructure its Electricity Sector: The European Union

How can a competitive market be designed and implemented in a federal system of government? How can policy for the market be developed in an historically balkanized market with decentralized regulatory authority? What decisions need to be made at the central level and which decisions are best left to local authorities? How can entrenched monopolies be displaced (or should they be)? Will functional unbundling be sufficient, or more required? Can a market function where every jurisdiction sets its own rules for retail sales? How much should regulators and policymakers defer to rely upon voluntarism by market participants? Should a mix of private and state ownership be of concern, and if so, to what extent? How should the network be governed? What should be the rules governing interconnection? How should network services be priced? How are externalities best addressed? What levels of cross-subsidies are tolerable and sustainable? How much should market power be defined and how are related issues best addressed? When are behavioral rules sufficient and when are structural fixes required? How are the rules to be enforced? Does all of this sound like North America? Europe is facing the same fundamental questions concerning electric restructuring. What lessons are accumulating that could cross the Atlantic?

Speaker One

The origins of the single market initiative in electricity and gas are rooted in Article 95 of the EC Treaty itself, which seeks to create a single market in Europe in all sectors, not just energy. The EC Treaty is based on the concept of subsidiarity, which is very hard to define. It means that EC directives are left to member states to implement, to take into account local or national needs and interests. The EC is wary issuing directives and regulations that interfere with property interests, some of which are constitutionally protected. Because of subsidiarity, the EC directives do not guarantee an identical outcome in all member states. Please note that the EC Commission is not a federal

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regulator. It has power to make regulations that have direct effect as a matter of EC norm. They are not subject to further national implementation unlike directives, which require national implementation regionally and change law or some secondary legislation.

The 1991 Directive created absolute havoc and for the next five years the EC was unable to do anything. There was certainly a huge reaction against it at a political level and industry level. In 1996 they were able to put out a directive that is called the IME directive. The equivalent directive in gas saw electricity as competition in generation. There was a system of free-market entry with an authorization process of permission based on transparency and common sense, and easy to fulfill the conditions for a system of competitive tendering. Retail competition was to be introduced. There was a system of negotiating third party access, or regulated third party access. There was the notion of the single buyer model. Eligible customers able to participate in customer choice were very large indeed. Consumption was in excess of 100 GWh and there was to be progressive market opening to around the 35% mark. The more interesting feature, from our perspective, was that there was to be unbundling of the transmission system operator, but functional only, not corporate, no real separation into a separate, independent company.

They also created a distribution system operator. They were very focused on the difference between T and D at that time, and the TSO was to be independent, at least in management terms, with broad responsibility for operations, and maintenance expansion in order to guarantee security of supply. The non-discrimination obligation and the TSO can give a priority to renewables and indigenous funds up to 15%. It was not very prescriptive.

There was a system of negotiating third party access based on a published indicative range of prices, but in fact a regulating access regime under regulated transmission prices was adopted in most member states, with the notable exception of Germany, which didn't adopt a regulator at all and where the only competent authorities are the competition authority. The single prior access was based on a published non-discriminatory tariff but eligible customers were allowed to contract directly with generators and retailers. There was some emphasis on making sure there were effective dispute resolution processes, in case people couldn't get access on a negotiated basis. There was quite a lot of concern about public service obligations. These are obligations that have been placed on particularly the state-owned utilities to an obligation to serve and connect protection for low-income consumers and environmental protection. The service obligations are imposed on these utilities as a method of wider subsidizing of the utilities or in some way limiting competition. They were subject to notification. There were derogations of spending cost recovery around. Curiously, the directive talks about existing commitments; it doesn't talk about standing cost quite so blatantly. There were a lot of early extra cost applications filed, most of which were actually thrown out as not being true standing cost, but it is certainly more fair on real existing contract commitments than they're likely to get. Then there was the famous negative reciprocity clause. If your neighbor wasn't as liberalized as you, you didn't have to allow exports into your territory from your neighbor.

The IME directive was made effective in 1999 in most member states, but not in Belgium, Ireland or Greece and resulted in some different outcomes. Because of it, we are making late proposals to the Commission to amend the directive and to put in place a regulation which is close to the energy regulation in direct effect which we published in March 2001, but there was no political agreement in Stockholm in the spring of 2001. France and Germany opposed the 2005 completion dateline for full customer choice, which was cited as the reason behind it. The cross-border trade in the EC accounts for only about 8% of final consumption, and some of the rules on the cross-border trade were thought to be a glaring gap in the legislative framework.

The directive, which is really amending the original directive, talks about corporate separation of TSOs. TSOs will exercise full control over all assets necessary to operate, maintain and develop a network. An internal TSO compliance program will ensure that there is non-discriminatory access and we'll be getting to that in a level of detail and will hear the compliance officer's report. TSOs will be required to meet minimum levels of investment. Further market opening will cover all non-domestic customers by 2003 and domestic customers by 2005. Response to access requests will occur within two weeks.

Article 22 of the directive relates purely to interconnectors. The wording of it is curious insofar as it seems to make no national regulation compulsory, and it appears to preclude market-based transmission prices. In fact, the EC is about to publish a study on interconnected capacity and what they think will be needed. They are reviewing the detonation of available capacity and technical upgrades and standards in technical improvements that could be put in place to get more improvements with these interconnections. Interconnections are definitely needed between Italy, France and Austria, France and Spain, and between the UK and the continent.

The EC is allowed to set the level of compensation payments between the TSOs. They can issue guidelines with further detail and relevant principles and methodologies, for example, cost calculations or power flow measurement. There are a lot of details about not being against set charges and not being cost reflective and distance related.

The discussions take place in an ETSO, which is the European Transmission System Operators Association. CEER is the Council of European Electricity Regulators. The Florence Forum, which meets twice a year, is everybody in the industry, member states and the regulators. The EC has an open-door policy.

What's the relevance for the United States? The penny has dropped in Europe: they need to be more prescriptive as to the powers of TSOs and RTOs, and there's a distinct tendency getting to the detail of the design. Regulation is a critical issue at member state and federal levels. In focusing on interconnections, particularly as to pricing and expansion, they are not really looking at trying to enhance larger markets, as you are in the United States. They would like to, but they have a long way to go.

Speaker Two

This talk focuses on the same problem and the possibility of decentralizing the design of the market and tries to put together this design in a single, integrated market. In the second normalization report the EC said the objective is the single market, not 15 little markets. And the EC realizes that there are some obstacles to that goal, namely that corporate trade is difficult because of pancaking and problems with interconnection, which are recognized as key issues.

Since each member state has implemented its own design, it is difficult for consumers of one to get some supplies from another. There is no tariff framework for cross-border transactions.

The EC analyzed the problems and concluded that in order to remove them, one needs to reach an understanding about which costs may be recovered in the access fees; reach the conclusion with respect to nodal vs. transaction pricing; agree on the pricing policy that does not involve pancaking, and agree on policy for congestion.

The cross-border solution does not require a major overhaul of the whole system or a common market design. The agreement should be an access charge to the grid and an allocation of existing interconnection capacities, and congestion pricing should be added to the directive.

At the Florence Forum progress was made on the basic principles upon which a tariff must be based, but these principles have never been elaborated in a document. There is still some export tax inside the internal market, which sounds a little strange, but they reached an agreement. Things look less promising on congestion of interconnections. Quoting the Commission: "Capacity should be allocated through market-based mechanisms." In the same sentence, the adoption of these guidelines presents a step forward on this issue. Moreover, their implementation in practice at national levels is wholly voluntary in nature. We do not have the institution of standardized, commonly designed pieces to implement into the market safely. This means that we are too backwards on that condition. The logical conclusion would be that we should introduce those designs in the market, but this is not the case.

The Florence Forum could harmonize to some extent the access to the network, even though initial positions were quite apart. But it remains entangled in contradictory statements on congestion management because they could solve the first problem without questioning the market design, while the second problem requires a questioning of the market design.

On March 13 the EC adopted the proposal with great hopes, and 10 days later, Germany and France defeated this package in Stockholm. What comes next? Possibly the design will be implemented through the competition laws, which is an endless project. The EC is quite strong in competition law, except there is a clause that allows us to sanction a taking, if they can prove that the application of competition law would jeopardize the public service implications. They talk a lot these days about removing the bottleneck at the interconnection through the Trans European network policy. But more interesting is the reaction from the industry, which after California sees a protection. It is evident that it has been difficult to find a safe, consistent model.

Speaker Three

In Europe we have some subsystems like Ireland and Northern Ireland, some islands like Great Britain connected through links to continental Europe and Norway, Sweden, Finland and Denmark building another bloc. Then, we have the large continental network from Poland down to Portugal, which is expanding. Poland, Slovakia, Hungary and the Czech Republic were connected to the other continental countries in 1995. Countries like Bulgaria and Romania are in the process of upgrading their networks so that they can connect to the continental network together with Greece and the former Republic of Yugoslavia. This will build a very large continental bloc of interconnected countries.

In each of these countries or in a large region of them, there was one company in charge of transmission and system operation. In some countries, the transmission activity was part of a vertically integrated company that included generation and distribution. In others there was a fully vertical integration, or there was room for some other generators and/or some other distribution companies. We still have many different structures organized around the transmission system operator in each area. The starting point for this process is a high degree of diversity in terms of organization of the power industry. Two major forces acted upon the monopolies starting in the late 80s and then increasing in the 90s. There was liberalization as a value to be followed and pursued in many countries. It started in the United Kingdom, and it was then applied by all of the European countries. In the late 80s the political process of European integration or Europeanization of our economy started. These two forces acted more or less in parallel upon the vertically integrated companies.

These two forces split the vertically integrated monopolies in two areas: networks and other segments in competition. There are networks in almost all European countries, with the exception of Germany. The outcome of this process should be setting up a single European electricity market. But we are still far away from that reality.

The 1996 directive left a lot of freedom to the member states. In order to proceed towards an integrated market, we have to be pragmatic and to live with this diversity of organization for some time. In the Florence process the idea was to consider the transmission infrastructure, at least in continental Europe, so that each member state should facilitate as much as possible the access to this infrastructure by removing barriers and by introducing appropriate mechanisms for purification and congestion management.

An intermediate step is the creation of some regional markets. We have a very well known one in Scandinavia, Norway, Sweden, Finland, and Denmark. There is also a political decision to integrate the Spanish and Portuguese markets. There are conversations and some degree of cooperation between Holland and Belgium, Austria and Germany and so on.

There are technical, economic and institutional challenges. We have at least two main problems of coordination in terms of planning and operations. In the future the planning of the lines has to be somehow coordinated according to other criteria and this transmission infrastructure has to be seen as facilitating trade throughout Europe. This requires the removal of some bottlenecks, for example, Ireland and Greece. This is required to process coordination among the transmission companies, but also among the regulators. The final result will probably be a trans-European network. Since the EU Treaty in Maastricht in 1992, the EC has the duty to promote the development of trans-European networks, including electricity.

The other issue is operation coordination. Of course the integrative system is reliable. But now, it is being subjected to different operational constraints and to different rules of network access, which create new challenges for the network operators, such as qualification of the rules for technical operation of the network, including the interconnection. These rules have to be available to everybody and should facilitate trade.

Economic integration is even more complex. As the first step we need the physical integration of the network. We need to design and implement a wholesale market, beginning on a regional basis. Consequently, the electricity companies acting in Europe will have a new international dimension. It is difficult to move from a situation of national monopolies or national champions to a competition, where they lose market share and have to compete in their own markets with foreign companies. From a political and even from a psychological point of view in some countries, this is not very easy. Some companies try to become European companies instead of remaining national. But how to assess the market power while the market is not yet integrated at the European level is one of the questions being discussed nowadays.

Then the evolution of the spot markets will lead to the need for financial tools, which probably will cover the European area and will not be restricted to some local or national regional markets.

The final point is regulation. How will we organize the action of 15 different national regulators and share some powers and competencies between the national regulators and the European institutions, in particular, the EC?

We are still a long way from bringing to energy customers the choice and the information they need to fully benefit from the integration of the markets. We are in a phase where the old monopolies feel insecure and it is our task to help these companies overcome these difficulties. One of the best ways to overcome these problems is the use of new technologies. Information and communication technologies associated with some new generating technologies can make this industry very different from the one we've known over the last years.

Question: My sense of what's going on is that continental Europe learned nothing from the experience in England and Wales. How did it happen? The whole issue of market power has not been confronted in any kind of a coherent way. The point is that we can have a common set of markets and an integrated Europe, but that doesn't mean that it's all one market in an economist's sense. Maybe we ought to distinguish between a market place as a common set of rules from what may be very separate geographic markets, when there is congestion. Where are the European economists?

First Response: When the UK finds itself in a minority of one opposed to continental Europe, the answer is European politics.

Second Response: First, the economists have played a great role in these procedures at a political level with previous work done by bureaucrats. The second reason is there was a very strong tradition of state-owned monopolies that could not be overturned overnight. Finally, not many economists have been involved in this, even in a political fashion. The proportion between those who deal with macroeconomics and those who deal with competition and particularly competition in one sector is very uneven.

Third Response: The EC has little power to restructure the market. It tried to do it through competition law, but this attempt was not really clever. There is an exemption of competition law in the Treaty for companies that have a public service obligation. The problem with removing monopolies where you have the private monopoly so dominant is that it becomes impossible. Basically, you have to find some compromise, and the result is a meaningless situation.

Fourth Response: We learned a lot from the UK experience. It had a tremendous impact on development, both at the EU level and at the national level. It influenced the decisions made by the EC in the early 90s. The model has been considered by all countries. Nobody could escape discussion about the UK model. This debate is kind of a cultural debate. It contributed to the restructuring of the industry in all the countries and also at the European level. *Comment:* There actually is a political science literature on this subject. The author of a recently published book was from the Social Learning Group, about 35 people who conducted a big study on environmental decision-making. The subtitle to the book is, "Why is it so hard to get to learn from each other and use expertise in complicated technical problems that have big political impacts?" The literature suggests that the starting point should be that you can't learn from the mistakes of others; you have to make them yourself. The story from the United States isn't any better than Europe. I would argue that with the possible exception of New York, every experiment we have had so far with electricity restructuring in the United States has drawn bad lessons and made big mistakes that could have been avoided. We have the same problem that Europe has with subsidiaries because of the desire to have differences in different regions.

Question: The northern European model seems to work very successfully. There is the difference in ownership of some of the generation assets, because it's public and there is less potential for market power abuse. American psychologist Abraham Maslow says study success and you'll be much more successful. Why have we not seen more of the discussion of the northern European, Scandinavian model?

Response: The experience shows us that where there was a previous tradition of closed corporation among transmission system operators, it was easier to move on a more regional basis to integrated market. The market model implemented in Scandinavia has been considered and applied in several countries in continental Europe, in terms of software frames or general organization. But it is a problem of scale. When you have a large system, as in continental Europe, without the tradition of very closed corporation at the quasi-commercial level as it in Scandinavia, then it's a different case.

Comment: You seem to suggest that the central regulator is needed at the European level to get the market going, and that the decentralized solution would be inefficient. You have to take into account production efficiency and the institutional costs of the system. Production efficiency obtains a huge cost on the regulatory side. I'm not sure that the central regulator would do much good for the electricity market in Europe.

Session Two: Roller Coaster Prices: The Western US in the Past Year

In the light of experience and now many studies, how can one explain the extraordinary volatility of electricity prices in the western U.S. in the past year? To what extent, if any, do the prices reflect undue market power or market manipulation? What has been the influence of fuel, particularly natural gas, markets and constraints? To what extent did the controversial El Paso arrangements and changes thereof impact electric prices? What has been the impact of FERC's imposition of market mitigation measures? What accounts for the extraordinary levels of conservation achieved in California? How much of it was an anticipation of high prices and/or shortages and to what extent was it attained in response to CPUC actions in raising rates? What has been the impact of the expedited plant siting measures taken by California? What effect has the litigation regarding market abuses had on the actions of market participants? What impact have the actions of the CA ISO had on prices? To what extent have prices been driven by the insolvency of California's two largest utilities? How have weather and other external factors influenced prices? What have we learned, or what should we learn, from the experience of the past year?

Speaker One

During June through September 2000 in comparison to 1999, the market payments for electricity in California went from about \$1½ billion dollars to \$8 billion over those four months. The causes are: the increases in gas and environmental costs and the lack of hydro resources. Production costs roughly tripled in that period. The quadrupling of prices includes a component of market power rents, which ballooned quite a bit from 1999 to 2000, approaching the order of \$4 billion over those same four months. An indication of the competitiveness of this market is the intensity of market power in the summer of 2000, which is in many ways very comparable to that of 1998 in California.

If you look at the measure of market power as a function of how high demand is, what appears to have happened in 2000 is that we were pushing up against capacity constraints much more frequently than in previous years. Costs had risen so much that a mark-up of 50% over the marginal costs, which in August of 1998 would have implied a mark-up of $20-$30 a megawatt hour, in the summer of 2000, implied an increase from $100-$150 a megawatt hour. The same level of market power produces much more dramatic dollar amounts. It is very difficult to know exactly what's going on right now, because data are so hard to come by. But it is important to recognize that this is part of what happens in markets and we are unlikely to see them be perfectly competitive.

There has been a lot of focus on the tight planning margins this year, and they certainly were getting quite tight in the western U.S. throughout 2000-2001. It is becoming fairly well-known now that it wasn't just California that wasn't building new power plants but basically every state in the western U.S. with very few exceptions.

We cannot consider the tight margins that we saw in 2000-2001 to be an indication of the failure of deregulation to spur new investment, but probably just the opposite. They are a function of whatever incentives were being created in the late 1990s because of a five- or six-year lag in constructing plants. Since this was affecting the entire western U.S., this is more about the uncertainty of the restructuring process and the `mid-1990s perception of growth and demand in the western US. Since 2000 though, there's been quite a flurry of construction.

It was not so much that California demand spiked unexpectedly, as growth in the other parts of the west was proceeding at such a pace that it dried up the reserves that had been supplying California with both a competitive threat at times, and with actual power at other times.

Looking at 2000, the demand is down more or less 5-8% every month relative to last year. Many components are affecting that. Peak consumption appears to be down 5-10% during that period, and the weather has been very cool this year. The economy is continuing down.

Efforts to have people conserve to be good citizens have had an effect, although economists may not want to admit it. According to surveys, customers don't have a real clear picture of what an electric rate means in terms of how much they pay. There were a lot of headlines saying "the largest rate increase in history," "prices had gone up 50%," when in fact a large amount of retail rate customers haven't really had much of an increase at all. Only those who were in the well-above baseline levels have had a very significant marginal increase. It seems that prices that were in the $150-200 megawatt hour range throughout the winter have dropped down to the $40, even $30 megawatt hour range in the summer. It's a reversal of the standard winter-summer pattern. Prices have declined very significantly and there is not a lot of transparency right now. There is no power exchange and the bulk of trading is happening bilaterally over the phone, with most of the purchasing being done by the California Department of Water Resources that does not want to share its daily transaction information. But the signals indicate a very clear decline in which fuel prices and demand have dropped, additional supply has come on, and FERC regulations have been imposed.

The state is still the main purchaser of power because the large distribution companies have been unable to extricate themselves from their financial problems. The state has also signed $42 billion worth of long-term power contracts stretching out over the next ten years.

The next big issue is how the cost of the contracts, which now appear clearly above market prices, will be distributed among customers, utilities, taxpayers and so on. It appears that the cost will be spread out over some period of time through a bond issue and tacked on to electric rates, so it will be electric customers and not taxpayers paying for these prices. Large customers would prefer to have customer choice to avoid having to pay for these stranded contracts. There will be some kind of mechanism in which those costs are going to be covered, and it has eerie parallels to 1996.

There is a lot of tension between wanting to deregulate markets as soon as possible, but there is the apparent unwillingness of many regents to take the structural steps necessary to make sure that a less regulated or restructured market really functions like we want. This means putting a substantial portion of load on some form of real-time pricing and breaking up large suppliers to be much less concentrated. The standards that Texas adopted as a rule that 20% of the market is a barrier for the firms shouldn't be breached.

ISO administers in most regions and tells people what they can bid, or revises their bids, etc. In many ways this is a more intrusive form of regulation than what we had under cost of service. Now we're really almost engaging at the hour-by- hour operational level with regulatory oversight. There is a reluctance to take the necessary structural measures, and instead to rely on these alternative forms of regulation, which are behind-the-scenes to keep things quiet. It is questionable what the long-term consequences will be.

This is an issue not just in California, but around the country and probably around the world. The alternative to necessary structural measures should be viewed as necessary companions under certain circumstances. They certainly are not an excuse to not take the necessary structural measures of bringing in price-responsive demand and developing rational standards for what an acceptable level of concentration in markets would be. That's the main concern. Places in which real-time pricing seems to be taking hold, or experiments with most aggressively are all traditionally regulated, vertically integrated utility settings. Implementing some form of real-time pricing should be a requirement for more relaxed forms of market-based pricing in markets going forward.

Speaker Two

A lot of what we're talking about today involves the interplay or the balance between markets and government. Is this about market forces or about the political response to what's going on in the market?

I'll try to describe the two opposing points of view. One claims that anything that makes sense in a commercial context sooner or later will happen and the market always wins. The opposite point says that once you are done looking at technology and economics, politics will tell you what you will do in fact.

Which is the primary force? Do we put our chips with the market or with more extensive and perhaps more intrusive regulatory structures to correct things? We'll talk about what happened in the West, why it happened or what explains it and what we have learned.

First, if you're asking what happened in the West, you have to say, why did prices spike up and equally, why did they come back down? The charts of almost a 12-month period from different areas show a little bit of difference due to regional changes but by and large the curve looks the same. Between the point where it sharply goes up in June 2000 and sharply comes down in June 2001, there is lots of volatility and a big spike in December. Before and after look eerily similar.

Why did it happen? I'm going to focus on the market fundamentals. What really moves the market from my point of view as a participant is supply and demand – the fundamentals. On the supply side, you had the natural gas price spikes and quite interesting hydro output curves and all the new generation that has come on line. Looking at natural gas average prices at different delivery points, the curve looks an awful lot like that electricity curve. It goes up about the same time; it stays up about the same way; and it comes off about the same point. I think the most logical explanation is the correlation between electric price behavior and gas price behavior starting on the fuel side. That's the up side or the upstream side of the value cycle. And the correlation is close enough that this explains a great deal of what happened, if not all of it.

The next factor is hydro. Hydro production from April 2000-September 2000 shows an interesting curve, trending downward almost without variation or mitigation as it goes. Seasonally, it should have happened as the run-off season and as rainfalls came back, but it didn't. That was a very significant factor in explaining why that ramp-up occurs in the year 2000, to the extent that natural gas becomes the fuel that takes the place of this hydro generation and that it affects the marginal pricing in given hours. You're going from a very cheap marginal cost to a very high marginal cost, which coincidentally is spiking upward as hydro is trailing downward.

Why did the prices come off in 2001? To a trader, this little blip in April, May, and June of 2001 is significant, since people form their price views based on these things and behave accordingly. As hydro production, low as it was, began to show some relief, it was a very efficient snowmelt this year and it all melted at once, but the reservoirs were able to capture very efficiently the snowmelt in the Northwest. We got a little bit of rainfall in May and June of 2001, which to a trader begins to explain why prices are going to start coming off. So it is significant in terms of the way market participants behave.

The third factor is new capacity. Looking at the supply side of the fundamental equation, you've got about 6,000 megawatts of capacity in the West that you didn't have a year ago. Demand side is probably even more significant. We just talked about overall megawatt-hour consumption being off in 2001 versus 2000. But looking at peak days closely correlated to price spikes, the average daily peak load in June 2001 versus June 1999 was up about 13%. So in 2000, your average daily peak is high, year-on-year. The year 2001 is just the reverse: dramatic reduction in average daily peaks. The conclusion: you've got basically a 13,000 megawatt swing year-on-year when you take into account peak demand and supply resources.

Does that explain why it was higher a year earlier or why it came off a year later? Mostly. The market fundamentals here are very significant. Why did it also come down so steeply? Let me offer a couple of thoughts as to what might explain the steepness of these curves, other than market power.

One: the inelastic demand is nothing new. If you sit on the trading floor and listen to the conversations between traders at a peak hour of a tough day, you will find lots of utilities out covering our native load. On an hour ending at 1700 on-peak when the temperature's about 98 degrees, the traders will pay anything since they are not going to let the lights go out. And that's pretty inelastic demand.

Second: technology and infrastructure limitations. Don't count on things working the way they're supposed to, particularly at the most stressed hours when everything breaks and takes liquidity out of the market. It reduces the flexibility of response for market participants to the conditions they face.

Risk management: Prudent risk management is something that people accused California of not permitting and was offered as a tremendous fault in the market structure. What does prudent risk management look like from the standpoint of the given market participant firm? The companies are trading. They are taking risk every minute of every hour and managing that risk. When they look at commodity prices and we look at our open positions at any given time, which represent the level of commerce, they use value at risk or VAR, which is driven by volatility. When a firm's VAR goes up, it gets out of its positions and starts pulling back out of the market. In such situations, you have fewer players and less liquidity.

Credit risk: There were a lot of hours of the day, especially in the last year, when the companies simply wouldn't do business with a number of other players because they were maxed out on their credit. It's not just accounts receivable, but the forward market-to-market value of your transaction that goes into calculating credit risk or value at risk. And again it's prudent from the standpoint of the individual company that it takes companies out of the market at key periods, and reduces liquidity, which adds to the steepness of your price curve.

Operating risk, transmission risk: The only significant point is in the West. What you want to happen when you're in times of scarcity are people like me to move physical power across the country to get it where it's needed and where it can be generated. You can't do it in the West on firm transmission; it's just not possible. If I am selling into California or Oregon on a financially firm basis, somewhere in that chain of transmission transactions I've got non-firm. I'm taking a big risk here and may have to financially settle that contract at a huge loss, and I'm going to charge for taking that risk. There are plenty of companies that simply won't take that risk and just won't sell. We're not going to get caught paying five times in financial settlement what we thought we could make on the transaction. That, too, reduces liquidity.

Regulatory risk: People apply political risk calculations within the United States the same as they do looking at a market like Europe.

The conclusion is that these opposite models are both right. The market always wins in the long term but in the short run, you'd better be sensitive to politics. That means keep looking at the fundamentals, but always remember that when the heat gets too much and the outcome gets too intolerable, that government agencies, regulators and politicians will respond according to political formulae. As a participant, I have to know that, plan for it, and build it into my calculations. And there is a price.

What have we learned? If I'm a regulator, I'd start out with Hippocrates: "Help, or at least do no harm." Market forces are rational. Government intrusion is to be expected under some circumstances. But when doing it, remember the law of unintended consequences. The next is Shakespeare, from Macbeth: "If it were done when tis done, then 't were well it were done quickly." When the political consequences of market participant behavior are so intolerable that you have to get in, get in very quickly and then get out equally quickly. One should build relatively short-term measures, not build a huge, complex structure for a long time in the future, which strikes me as a mistake. Satchel Paige: "Don't look back, someone might be gaining on you." Don't be retroactive. There are circumstances where perhaps the law or the overwhelming political impetus says you have to go back and do things like unscrambling prices or causing refunds. But in terms of political risk the one thing you look at and the one thing you put a price on more than virtually anything else is the likelihood that somebody will change your transaction after the fact. That's the very essence of political risk. Finally, Heraclitus, who said, "You can never step into the same river twice; it's always different." If I was a policy-maker and I was trying to build something, I would remember that the next emergency wouldn't look like the last one. Let's not think we can out-think the next emergency. That's why you stay short duration and you stay minimal.

Speaker Two

I've drawn five conclusions from the events of the last year and a half.

The first is that any restructuring will produce unpredictable results and unintended consequences. The markets are the result of what you create and when you create a market system it is often unknowable. When you have unpredictable results, it's great if you can be light on your feet but mid-course corrections are very tricky, as we found out with California. Governor Davis found himself in a very difficult position of trying to make corrections to a program that had already been in place for some time and which had created winners and losers. There were a lot of people who didn't want changes to be made.

One of the consequences of having a market-based system in the West is that if we have typical commodity reactions to the need for the product, then we're all going to be in trouble. For the last ten years we all knew we were starting to run short of power. The Northwest Power Planning Council put out a paper saying that we're running short of power and we need to have people come forward with generation and that didn't happen. But as soon as the price went to $300 a megawatthour, people were looking for site certificates for about as much generation as 50% of the entire Northwest load. Obviously that's not going to be all built, now that prices have crashed. But if we have to go to extreme shortage in order to get orderly, planned generation additions, then I would just as soon go back to the good old days of utilities building generation and the states saying: "You can put that in the rate base."

An additional problem in the West is the hydro swings. It's very difficult to ask somebody to make an investment in a new plant if next year and the year after that, it might turn out that we get a high hydro year and there's 4,000 or even 8,000 more megawatts in the marketplace than there were before in a drought year. They're going to want to get very high prices for that power for the years, if they are going to invest in generation. And we do not have an easy means to smooth out the retail consequences of having price spikes of that nature, which may be necessary in order to ensure that the generation is there in drought years.

My second conclusion is that an effective federal-state partnership is needed to make this work. In Oregon, as we start looking at the issues that we will have to solve to make Oregon's restructuring work and that is the beginning of retail access, we see more and more issues that the federal government needs to be a full partner in. The failure of that partnership in the California debacle makes us all a little worried that California turned over the cost of its generation to the federal government and the federal government let it go to levels that couldn't be sustained in any kind of retail marketplace. No one had any incentive to pass it on into retail rates and that helped the problem get worse.

My third conclusion is that comparative markets can work but not yet. Since they haven't worked yet, we don't have examples of well-functioning marketplaces to count on, and everyone is very nervous. We don't yet have the technological and financial means to deal with some of the problems the marketplace creates. The demonstrated principal problem is that prices go to infinity when reserves go to zero. This problem could be solved technologically if PG&E had the ability to shut off every water heater in its service territory as reserves approach zero. Probably prices wouldn't go to infinity. It could also be solved financially with financial instruments but those are not yet available in the marketplace to any great degree. And those things need to develop if we're going to have an effective marketplace. The debate between 10% and 20% seems irrelevant to me because people with 4% of the market in California were able to exercise market power in the last year and nobody was prepared to step in to prevent them from doing that.

My fourth conclusion: don't expect the political system to step in while regulators try to work things out in the marketplace and don't expect the political system to cooperate when you need it to. Governor Davis, in meetings with Governor Kitzhaber and Governor Locke, made it very clear that he felt that raising retail rates before prices came down just rewarded market power and that it would not have been an effective result because the initiative process would allow people to come in very quickly and try to reverse the result and then screw it up even worse in California. He's trying to manage a very delicate political problem at the same time that we have this horrible market problem. Governor Davis was very fortunate in having strong Democratic majorities to work with in California in both the Assembly and the Senate.

As you may know, the Oregon legislature passed a market access law in 1999 that is to take effect about October 1, 2001, where commercial industrial customers could have access to the market. As California's situation became apparent, there was an enormous amount of maneuvering by both the Democrats and the Republicans, and there was almost no support for continuing our market system except by the governor and the president of the Senate. They simply said this shall not pass. If they had not been there, we'd be back to cost-paid regulation just like 1980.

My fifth conclusion is a hope that organic, incremental, slow approaches to marketplace reforms have the best chance to succeed. In the Northwest we use the salmon analogy: the salmon will move downstream when they're ready to. What we developed with the Oregon legislature in the 2001 session was putting off the effective date of market access, allowing them to go into the market on March 1. It requires the utility to offer a cost-of-service rate for at least 15 months after that and it could go much longer. We have to make sure that the markets are open and all the relevant protections are there before we can actually start operating. I think there were about 12 different relevant factors in prices coming down, but I'm not sure that gas prices were one of them.

Speaker Three

Are we ready for competition in electricity? The California market design essentially was to make the market so hideous that no one would be in it. People would rush to the bilaterals and develop them on a very fast time horizon. Then the CPUC came along and said we don't want you in the bilateral market; we want you to be in the spot market. So they designed these things so they wouldn't work and forced them into it.

2000 market fundamentals: unlucky weather, high gas prices, pipeline capacity problems, high prices for NOX, emissions trading credits and the high HHIs. Why did the prices go up? Weather is one of the answers; market power in the gas and electric market is another. Other answers are: high natural gas prices, poor market design, disincentive for hedging, demand growth with weak price signals, very weak price signals, credit worthiness, high environmental cost and old generators.

Prior to the FERC April 26 orders, it was the fiduciary responsibility of generators to maximize profits. They were asking on behalf of their shareholders and if that meant withholding power from the market to drive up prices that was their legal responsibility. And there were few new generators, maybe six, maybe twelve?

This sort of schizophrenia for the spot market was not peculiar to California. Almost all public utility commissions nationwide have been forcing their gas markets onto a very short-term purchasing regime because it's been a reasonably good bet. This is not unusual except the PUC, like most things in California, did it in spades. Not only that, when we force people into the spot market for electricity for risk purposes, you force people all the way back to the chain into the spot market; you couldn't get firm capacity on SoCal Gas.

The good news is that the price in gas has gone up and come back down and there's been a huge rig response. The price is now $2.30 and we probably had at least double what we had a couple of years ago in terms of rigs running. But we have a whole bunch of rigs chasing $2.30 prices. The chatter in the wellhead market in gas now is that maybe we'll be withholding some of our gas from the market. This is a periodic event that happens every time you have a bubble. People try to talk up the issue of maybe if we all withhold a little bit the prices will go back up.

In California, the gas market was even worse. There were some perverse incentives. You couldn't get firm capacity on SoCal. Another issue: it's very difficult to discuss market power in polite company. There are a lot of people who come into FERC who are paid good money to tell me that it's necessary to exercise market-power in order to capture your investment. My answer is you probably made the wrong investment.

On April 26 FERC didn't want to do mitigation after the fact. It's messy, it takes too long and doesn't make a lot of sense but it creates a lot of risk. The Commission said do anything you want up until the day ahead and if you haven't sold your capacity by then, you have to bid it into the market at your marginal cost. We also said that the buyers had to be credit-worthy and they had to submit curtailment schedules. We restricted it to Phase 1 and the first time that this mitigation triggered, the price dropped from $300 to $100 in an hour. Somebody described this event as a demand response.

Why did the prices come down? It could have been competition from new generators, but I'm not sure that many new generators were on-line when the price started coming down. The outage rates have changed on the old generators, which are now back generating a lot more than they used to. But you have to realize that after April 26, withholding changed from being your traditional responsibility to being the elite.

The demand response: The question is whether or not that was a public duty not to consume, or whether or not the increased prices were actually affecting the demand. It's not clear whether it's more hydro or a cool summer. We'll have to sort that out. Certainly we've seen the gas price decline both at the California border and in the wellhead market in general. And there's a stunning correlation to the expiration of the El Paso affiliate contract.

Lessons: We did learn the big lesson on hedging, although it may come as a bad lesson for this year. A lot of commissions turned around on hedging. Now it turns out that hedging right after the price fly-up was probably a bad idea, but on a ten-year horizon it's ok.

You need demand response and this is one of the most important lessons we're learning. You don't need a concentrated market if you have high demand elasticity, to get a very high price response. And the demand elasticity was zero. As a matter of fact, if we would have done something as simple as saying that the ISO or somebody has to guarantee the creditworthiness of the participants in these markets, they would have said you can't bid vertical demand curves into this market because you don't have the money to cover it. You need an unbiased ISO, RTO and an independent board.

You need a good market design in order to do market power mitigation properly. The good news about this market power mitigation is that, in theory, if you have a good market design the outcome is not punitive. You could make mistakes estimating marginal cost, but it's the competitive market.

Risk evaluation is really hard and we don't do it very well. ISOs should not be a market operator or participant taking positions in the market, which essentially creates problems. You need creditworthiness standards in the markets that are run by the ISO or RTO. Maybe you could get them into the market in emergencies but I would try to seriously circumscribe it. We really need to work the demand-side bidding aspect but it has to be the load-serving entity's responsibility. I don't want to put that burden on the ISO and the RTO.

We still have a lot of evolution to do in terms of software, which was found out in the Northeast RTO mediation. And ICAP responsibilities also need to be the responsibility of the load-serving entities. But you can get out of your ICAP responsibility simply by being able to bid into the market.

If you have a day-ahead market, you don't have to worry about immediately trying to turn somebody off on a second notice. You can do the mirror image of unit commitment where you can get industrial customers to say, I want to run for eight hours or I don't want to run at all, or I run for 16. You can do a lot more in the day-ahead market than you could do in the real-time market and that makes more sense.

We have to try to let the thousand markets bloom in the off-RTO sense. That's not to say you shouldn't have an RTO market; they should be working in coordination with each other. You shouldn't penalize people for being in the RTO or the ISO market or try to subsidize the off-RTO markets.

If you need good market design, you need to recognize and mitigate market power. I'm not sure that I know of a structural remedy that is severe enough to mitigate market power when the demand's really tight. When it happens, you want to institute market power mitigation, if for no other reason than it's politically unacceptable. Forcing people to structurally divest to a fare-thee-well for events that may occur 40, 100, or 200 hours a year seems to me to be a very harsh remedy to get your market power mitigation. And I would respectfully disagree with the previous speaker that it's that difficult. The only choice here that makes sense is market rules.

Question: New conclusions need to be drawn, but California was working before things blew up. None of us necessarily thinks that existing designs in Europe, Argentina or PJM are perfect. But what are you looking for? The conventional wisdom is that regulators actually shouldn't intervene when things go wrong because price caps tend to distort market forces. In the California circumstances, what was your particular justification and why did it work particularly?

Response: The problem with translating, particularly the European models, is that there's such a difference in business culture and other things, for example, government relationships with these companies, that make it difficult. If you added up all of the damage from the California debacle, it far outweighs all the gains that have been made from efficiencies by going to markets in the entire US. As far as Americans are concerned, at least the man on the street and their representatives and legislatures and Congress, they think this is a bad idea. The California debacle has taken the political stuffing out of restructuring almost completely which is very fortunate.

I'm looking for a market that doesn't produce extreme volatility and distortions that end up distorting prices such that we have economic consequences in our state economy. It’s a marketplace that has orderly additions of generation and transmission, not ones that come in only in response to extreme shortage. It’s a marketplace that provides significant incentive such that demand-side actions can be laid equally against generation-side actions.

Until we have those things, which would require new financial instruments and some advances in technology, I don’t think there’s going to be much faith that markets can avoid going into high prices and ending up with shortages. Until we get that faith politically, new restructuring initiatives seem to be dead.

First Response: Political, legal and economic answer: It became politically impossible to let the California market continue the way it was and something had to be done. Legally, we are under a law that says that wholesale electric rates must be just and reasonable before they’re charged. And market power is simply bad.

There are three reasons why we should intervene when people may be exercising market power. And the April 26 order did three things. It chose conditions under which they would exercise this mitigation so they weren’t very frequent, but they were there when it was needed. I’m not sure that Phase I is the right evocation but it wasn’t all the time. I would argue with the characterization of price caps, which to me were market-clearing mechanisms. This was the result that you should have gotten if you had a competitive market. If you did it right, there was nothing punitive about what you were doing.

I talked about the April 26 order and not the June 19 order, because the latter didn’t have a market to mitigate in the entire West and started to stray away from marginal costs and went to more of a price-check regime.

I don’t believe that there were a lot of inefficiencies in the market, but a lot of income transfers. If you look at the standard economic model, when you have very low demand elasticity, you can raise the price considerably, without doing lots of damage to efficiency.

Second Response: The conventional wisdom is you let the markets do their thing, but I’ve never understood that concept as applied to California because I don’t know anybody who thinks the market was designed well. Even its authors now disown it. So the market was clearly dysfunctional, so the logic of “let the market do its thing” just doesn’t make any sense. Whether the intervention was correct or not you can argue about, but not to intervene in that situation seems to me kind of a bizarre result.

Comment: The price cap is $91.87 currently. It’s not the price cap that brought that price down; it’s the 13,000-megawatt shift in the supply and demand balance that produced those prices. The real test right now, when prices are low, looking forward, is whether the current regime will encourage sufficient investment so that you have plenty of capacity on a going forward basis.

Question: The clearing price, or a cap, applies to sales in and out of California and persons who apply to a Northwest utility or generator that’s selling into California also. The problem has to do with seasonality, among other things. In the Northwest we are winter peaking, and California is summer peaking. It doesn’t seem that we’re looking for a price signal, to base it on a California least cost and least efficient generator. But applying it West-wide could potentially penalize entities in the Northwest.

The comment was that we should proceed incrementally, which sounds safe. Oregon’s customer choice plan, which goes into effect in March 2002, provides almost six choices: three environmental green choices of various blends and colors. The other most interesting thing we have is a default supplier choice. And a particularly attractive issue is a time-of-use choice that all customers are provided, including residential customers, and we hope that eventually we get into real time pricing with this choice.

Question: Do you think if everyone proceeded incrementally … if everyone, for instance, adopted the Oregon model rather than the California model, do we ever get to test whether the marketplace works?

Response: Responding to the first question - if you think that $90 is too low a price cap, you can go off into the bilateral markets and, probably unfettered, negotiate a price that's higher than that. I don't think there's any mitigation on those longer-term contracts if I recall. We've always been at risk that we could be forced to a refund situation. The Federal Power Act says that if we find rates to be unjust and unreasonable, we have to fix them to be just and reasonable. There is less risk that if you go out and sign a contract for more than $90, we probably won't mitigate it unless there's some kind of extenuating circumstances. If you think that those other mechanisms are better than the ones we have employed, we could ask FERC to implement them.

Again, the mitigation scheme is one that says that we don't want generators withholding power from the market, but we do want the price and the market to clear, which was the overriding philosophy in those orders. Without a single spot market in the West, you could implement other strategies or requirements that would get you to essentially the same place, although they would probably have more transaction costs. The easy way to avoid all of this is to get yourself into a bilateral deal that has you running in your real time.

Second Response: Referring to the question about incremental deregulation: what does deregulation mean? The focus in this country has always been on the customer choice aspect of that. But probably the whole notion of it is a market process that's driving the choice of a kind and location of new power plant construction. And in that sense, we've been on a process of gradual deregulation in this country for fifteen years.

There has been a near elimination of the construction of power plants by utilities under cost of service regulation, replaced with wholesale generators that are building power plants under alternative arrangements, but usually not including a guaranteed recovery of cost.

Where California really differed from other regions was in taking a very large portion of its installed generation and putting it on a market-based rate very rapidly, as opposed to other parts of the world, where there was usually a retention of generation by vertically integrated utilities, who were also buyers, in many cases, or there was some form of contractual arrangement on the part of the distribution companies that expired gradually over a period of time.

Comment: We do have a market design that works, in the Northeast. I see a way to solve the provider of last resort problem and the generation siting incentives and all of that with the markets that we have. Could you provide me with some insight about why we, if we talk about this at all, we whisper about it?

First Response: There is no question the markets in the East have performed better than in California. But it's important to also recognize in PJM in particular the differences in terms of who owns the power plants and what kinds of incentives they have. There are still power plants owned by vertically integrated utilities that are under rate caps, and their incentives for pricing and selling those plants are very different than an exempt wholesale generator that has no load obligation. There are underlying contractual arrangements that serve the same purpose of vertical integration that are still mitigating those things. It's important to keep that aspect of the equation in mind when we're comparing market performance, that it's not just the design and the market rules that affect these outcomes. It's certainly the incentives of the players using those market rules.

Second Response: We sometimes forget that for PJM and New York, the change to an ISO was really an incremental change; things have been moving slowly in that direction for a long time. In California you had a flash cut, so it's not surprising that California would have done it so much more wrong than the Northeast.

Question: Why didn't you have any new building in the West? The mantra is that a load response program is going to save us. But nobody wants to curtail demand. What are you going to propose when load response becomes a defining feature of a successful market and you have given no incentive to load response because the political structure responds instead and artificially mitigates prices?

First Response: There is considerable evidence that demand response can work and it's worth some experiments. In Seattle they have Gulf Power's program – with a lot of residential customers – for a certain number of hours a month they can shut off their pool pumps, air conditioners and water heaters. The approval rating on that program among their customers is sky high. They've reduced their bills, the utility is better off because they reduced their peak, and it's made a big difference.

Answering the first question: before we went into a crisis, independent non-utility entities that built generation should have come forward and made rational decisions in the marketplace: sometime in the next three years that this generation is going to be needed. Nobody wanted to step forward until it was very clear the surplus was over. They waited until it was crisis time before they jumped in and the consequence of that behavior is that the price is going to go way down.

Second Response: The load-serving entity has the option of explicitly bidding the demand side into the market that is physically curtailable, or they may have to basically be covered by generator option contracts that, again, are physically feasible.

Third Response: The closer you can get to real time pricing, it means bigger customers, and the quicker you get there. Until you get there, the whole notion of the price response to the availability of the resource is so enshrouded in complexity that it's not very efficient at the peak - they're not quick enough. If we ever evolve to a contractual regime, customers could then see what they have to pay for power and make a decision whether or not they could sell that power back into the market. Hopefully, it is what the industrial customers will eventually evolve to, that they'll have contracts that they can decide whether they want to sell them back into the market.

Question: We have a lot of new generation proposed, the prices have gone down, so one could assume that that doesn't necessarily mean that all of that new generation will come online at its expected time - you can hold onto a site certificate for awhile and not come online. Based on what we learned, will we will get to a point of a more gradual addition of new generation?

First Response: If there's 36,000 megawatts out there under development and if you worry about it, there is an easy way to alleviate these fears. My guess is that you could probably get people beating down your door if you want to sign a long-term contract.

Second Response: The problem is we should have been there two years ago. Markets aren't always rational, but we act as if they are. And a rational person could have looked at what was happening to the surplus in the West and said this is an opportunity. That would have been a rational response.

Instead, everybody waited until prices went through the roof. And now they're coming way back down, which is understandable.

Question: Do you foresee a point where we will be able to provide the right price signals and incentives to get a more steady flow of new generation rather than a lot of volatility in the generation at a level that's significant and lower than what we saw in 2000, which generated all the new proposals in the West? Is this what we witnessed, just normal market behavior, or where there are real explanations like this transition from the cost based plants to an open market that were responsible?

First Response: Markets do behave rationally, but are not pressing and people were responding rationally to extreme circumstances. Most of the time you're wrong when you look forward. Market participants are rational, but certainly not able to foresee a future any better than the rest of us. If you want people to come in and build generation, be ready to sign a contract, or provide them with evidence that will cause them to conclude that they can earn a reasonable return on their investment. If you do that they'll invest. The time when nobody built anything was a period of regulatory uncertainty. And you can do it by contract or you can do it by being patient and letting the market work. These price fights were horrendous and that's certainly not what you want. But a market that works is one that efficiently allocates resources, which means you're going to have some fluctuation for that to happen. That's how the supply and demand balance will right itself. The big spikes produced a lot of so-called bragawatts, a lot of press releases about projects that are going to be built.

Question: One of the things that I worry about is that people will forget that before the summer of 2000 the California market was already in trouble. But this problem is festering in the West: a very powerful governor who's not confrontational with the federal government or the federal regulators, a complete implosion of the market operations and no process in sight, no political courage to do anything about it, or at least nobody can do anything about it. Is there any way to get out of that? Can the federal regulators do something? Can we have a larger RTO in the West or is this going to be an East Coast conversation?

First Response: People are talking about how to right the market or how to get the market back to some kind of rationality, but it's going to be hard.

Second Response: The political reality is that regulators do have a lot to say about the esthetics of that boom/bust cycle, and there may be ways to temper between boom/bust and central planning. A properly working market based on something like PJM or New York, in the abstract but not their particulars, may be able to be tuned to allow some degree of market participation without necessarily having a boom/bust cycle. But inherently that's a political judgment and not a market's judgment because it's based on the esthetic that it is unpleasing to have a boom/bust cycle. But there's nothing necessarily wrong with that in the way a market works. There is a concern about proceeding into deregulation at the state levels with retail access being in the lead. Except where we do have direct meter, things like provider of last resort and retail access for residential are horrible things. The efficiency gains aren't there and it's a net loss. We're going to have everybody picking their own supplier or design issues that are really very, very difficult to implement.

Third Response: When the California market started, it was fundamentally broken. It produced low average prices, there was no geographical dispersion to those prices that would have produced appropriate pricing and helped some locations. The physical dispatch of the market never matched the financial dispatch of the market, so there was never a physical representation of the market in the market, which is one of the big differences with the Northeast models and the California models.

There was a market that produced low prices, then a set of generators that came in as incumbents making new purchases of generation. Once they saw they could abuse the market and use market power they had no incentive to have anybody fill anything at that point because they could exercise some market power. This is an irrational market in the sense that it is fatally flawed and it has no appropriate response to the physics or the economics of the grids. We're worried about the sudden big response. If we would have had an appropriate market from the beginning, we would have had the incremental changes that we wanted, we would have had the geographic signals to build generation here, and only in this amount it would be much clear at least. We can look at ways to follow the Northeast models.

Session Three: Making Markets Work Under RTOs

The FERC seized the initiative and made plain preferences for the size and scope of regional transmission organizations. The new initiatives changed both the definition of who would be in the room and the dynamic and development of RTOs. Having defined the boundaries, the next step is to define what happens within and across those boundaries. A standard market design holds appeal in the ability to benefit from best practice. Allowance for unique approaches in each region holds appeal in allowing for voluntarism and different needs. At a high enough level of abstraction, there is a standard market design in the principles of open access and non-discrimination. How far into details will this common principle endure, and when do the details require flexibility? What criteria apply in making this decision? Who decides? Consolidation of control areas is easy to recommend, but how big an area can be controlled? Would standardization inhibit or enhance market performance? Does flexibility create more problems with seams? How do the mandates for consolidation affect the timing of RTO operation?

Speaker One

The focus of the speech is organized into three distinct premises. Point number one: economists don't make markets work. They work or they do not. In Darwinian fashion, transmission markets across the country have evolved to better equip themselves to the unique characteristics of their own environments. What works in one region may not work in another for reasons that are external to the market itself. We can work toward the ease of entry for new generation competitors, open access across transmission grids with independent oversight and transparent information flows. These will always help a market work better but as we've seen in California, attempting to force a market into an arbitrarily pre-determined region or structure is counterproductive.

The markets we now see across the US did not sprout from the same design, but from several seed varieties, each with its own personality. Our goals should be to help the markets co-exist in a manner beneficial to consumers. It should not force one market design over the others and abandon the benefits others have to offer. Forcing a specific market design where it doesn't fit encourages market participants to look for ways to the system, rather than to spend their energies looking for ways to improve their performance.

The NRC Control Area Criteria Task Force final report touts a market design that does not use the old service territory concept of an integrated utility as a framework for independent overseer. It proposed unbundling the reliability functions, proposing separate independent authorities for security, interchange in balancing and compliance monitor. These functions would work in concert to manage the interaction of all market participants and are contestable if someone can provide a better, more efficient approach. This is a radical diversion from the service territory concept we seem to be carrying with us out of regulation into competition.

That kind of creativity is what will allow us to craft the healthiest markets. We are overly quick to look for the perfect 10 in market design. So far, there isn't one. While some appear to function more successfully than others, each has its shortcomings. We can't pick any single model and say it will give us exactly what we need for all services.

PJM has been touted as a model to follow due to its successes in its own region. It may be the best possible design for pool- type RTOs but it is definitely not the best for all RTOs. PJM is successful now because it has been customized and upgraded to change with the times. It should be noted that PJM is not without its critics who discuss areas like FTR allocation, billing and settlements and transmission building to relieve constraints.

Before we categorically speak that one market design works better than another, we must also examine the tangential issues and conditions that affect that market. In the case of PJM, the market structure as a whole is not necessarily the only source of the organization's ability to perform. There are also rules unrelated to market structure. For example, in PJM, the requirements for a large reserve margin are largely responsible for customers' ample power supply, not just market design alone. And very little trading occurs within the boundaries of PJM. Most of it is traffic around its borders with customers and via the PJM east and west hubs, respectively.

Point two: Standardization can play a positive role in efficiencies of scale, seams issues and some protocols. There is a value in standardization and we are used to it. Forcing a single standardized structure among pre-determined participants is simply reverting to a more comfortable, familiar way of regulated monopoly life, a way that does not require us to test the metal of our own ideas. Therefore, it is comforting as we brave the unfamiliar waters of competition. It's time to give up that security blanket though.

With FERC order 2000 now 21 months behind us, we are encouraged to find voluntary allies to establish RTO markets that would create pure seams and robust energy markets across the nation, which was in progress. Then, in July of this year, millions of dollars after we had begun our compliance efforts with order 2000, it was perhaps superseded with a series of orders requiring us to affiliate with specific neighbors in pre-determined configurations that would create four super RTOs and ERCOT.

There is nothing wrong with such an idea. But voluntary membership is still preferable, and the market structure should not be dictated. Mandating artificial market size distorts the markets we are trying to create. Being provided a strict regulatory compliance framework is what we are used to. It takes away the stress and challenge of creatively designing a new market structure that would truly foster a healthier electric market through competition. It requires a force fit of models that have not been proven to provide either investment incentives or the benefits of an owner-operator model. Just as our market environments have evolved over time, so would our markets. Mergers of RTOs would come as naturally as mergers of utility companies through allegiances that make sense for the participants rather than each of us taking our own assigned seats. There will be some winners and some non-winners, but that's the nature of competition.

We are within three months of our deadline for voluntary RTO order. We've spent millions of dollars and millions of hours working toward compliance with that order and it can work. Some analysts have speculated that starting over with the development of mandated super RTOs could take as much as three years to comply. States are scattered across the spectrum of competitive restructuring. Many are already there, some are half way, and sometimes thinking of turning back.

Deregulation and retail competition are being blamed for a lot of evils right now. Retail competition absolutely cannot work without a reliable transmission grid. We must provide as secure and reliable transmission grid as possible, and we must do it as quickly as possible to help the competitive states meet the goals they've set. They need to be able to depend on our help and they need it now, not in three years. It is to say that we've already begun a race that's worth running and we did not have a false start. Reining in the market participants and telling them to start over will not improve their success rate. It will simply delay their victories.

Point three. We have adopted the mantra that bigger is better, but given the physical realities that there will never be a single transmission market in the US, nobody has addressed the follow-up question, how big is too big? Currently, we have 20 RTOs proposed, including several that are discussing combinations. Now we are told that we need four RTOs and ERCOT. What if we combined the four RTOs, or even the four RTOs and ERCOT into two RTOs, east and west? What if we combined them into just one, Pacific to Atlantic? Could we add Mexico and Canada?

The structural physical reality is that this country can never be fewer than three RTOs; the eastern grid and the western grid cannot be combined into one; and ERCOT cannot be combined into either. We cannot have a seamless transmission grid that is physically impossible at this time. Theoretically, the most desirable would be a single RTO for the east and a single for the west. But it is not doable at least in the short run. What is the logic of trying to force the various markets into rigidly segregated regions that may or may not work for the sake of continuing to work toward one market? There are physical constraints and tangible realities at work. Ignoring them won't make them go away. Meanwhile, we've not adequately studied the point at which economies of scale are superceded by the inefficiencies of scale. To say that bigger is inherently better is to make a gross assumption that may be erroneous.

We should try to put in place the necessary elements to allow the market to function effectively. These include open access across transmission grids with independent oversight, ease of entry for new generation competitors, exchanges, transparent information flows and market oversight. Once the market fundamentals are in place, the market will develop on its own based on supply and demand realities in each region. We will not have standard reach in characteristics and, therefore, standard design will not work.

Regulating a market by prescribing a market design can be the recipe for the disaster. Resist the urge for a more comfortable environment and allow markets you've each created to grow and evolve. Be alert to what works in other markets and what doesn't and be flexible toward evolution. Rather than falling back on the crutches of standardized regulation, be receptive to the potential reward and inherent risks of a thriving natural market.

Speaker Two

There are two broad approaches to the problem of the commons associated with network externalities in a manner compatible with a generation market. One is monopoly management with incentive pricing. It results in a powerful monopoly with the familiar problem of finding the right incentive regulation. But if we knew how to do it right, we probably could have stayed with vertically integrated monopolies in the utilities. It works in theory, but does it work in practice? The other approach that we're exploring in various parts of the country is market mechanisms with tradable transmission rights. The central problem is in the impossibility of defining the available physical transmission capacity that would accompany future dispatch requirements. That's the dominant theme that tends to be proposed, although we come back and forth periodically to try and revert back to the monopoly concept. But you can't do both at the same time.

When the initial filings came in for the RTOs, they were not very satisfying. They displayed a great diversity of approaches, but there were some common themes. Most importantly, the emphasis was not on the essential elements that seem difficult and controversial. There was a lot of discussion about governance, voluntary process, incentives and transcos that seemed easier to discuss. But the details of how we're going to actually do the critical components like congestion management, balancing, ancillary services and transmission usage were only sketchily outlined. If you looked at them closely, the pieces didn't fit together. Faced with a stalled process, FERC ordered the creation of larger regions. The mediation processes in the Northeast and the Southeast looked at details and found that they mattered.

The message we got is that trying to have decentralized resolution of all of the issues does not work. The evidence of it also comes from the Northeast mediator's report: "I purposefully cast the mediation task as procedural from the outset.… Attempting to resolve extremely contentious substantive issues among such a large and diverse interest group at this stage ... would be unproductive." But the mediator was unable to ignore the details: "The PJM platform is sound and proven – within its region. That region, however exhibits a substantially lower degree of divested generation than New York or New England. The same observation applies to load pocket problems."

Everything depends on everything else, but you cannot do everything at once. There is always the tension of what to hold fixed while trying to solve one part of this problem. The core of the market design platform is important. Then the other things are important: governance, institutional structure, and a common idea of the market design platform.

What's at the core? There could be a debate on the most critical functions in terms of interactions within and across regions. The list might include: congestion management, balancing, ancillary services and transmission usage. These pieces have to fit together and cannot be designed separately. It demands establishing the rules under which the market is going to operate. Flexibility in other things is quite desirable, but the critical core elements have to be designed sensibly.

One approach is management through a monopoly: an independent transco. It would have the advantage of owning the wires, running the whole system and providing all of the critical functions: congestion management, balancing, ancillary services, transmission usage under the broad heading of what's included in the dispatch. If we knew how to provide the incentives for that entity, we could solve this problem.

In the South they were going to have an independent transco that would be an owner-operator, without those words being quite precisely defined, but which would have benefits in terms of efficiency and accountability. This is an appealing idea. But its attraction fades significantly if it doesn't really provide a radical alternative to good market design. The rhetoric confronted reality in the Southeast power grid mediation. Separation of the key functions responded to the diversity of transmission owners and conflicting interests. This leaves us still with the task of designing the market.

The list of the independent market administrator's duties is not fully specified. It appears that it will not fall under the administration of the transco but under the administration of the independent market administrator. There is also a problem about transmission competing with generation. The market participants did not want to have this critical set of functions under the administration and complete control of the independent transco. There had to be some separation, some independent entity that is going to perform those functions.

What have we learned from the lessons of market formulation? I have selected four things that are relevant. The first is, "Don't assume it is easy to muddle through." Errors are costly. Bad market design leads to serious disruption itself, with the corresponding evidence of PJM in 1997 and New England in 1999. Bad market design helps make bad problems worse, like in California. Bad governance structures make all problems more difficult.

The second lesson is, "Get the prices right." When a monopoly makes all the decisions, the details matter less. But when market participants are given a choice, it is critical that they see the right prices. Market participants will respond to incentives. That was part of the underlying theory of the foundation for restructuring. Opportunity cost pricing supports efficient behavior. Otherwise the system operator and the regulators will be forced to intervene with non-market mechanisms that negate the broader purpose.

The third lesson is, "Recognize that the market can't solve the problem of market design". There are too many moving parts. Absent strong public oversight, the complex interactions and the competing interests provide a textbook case for sacrificing the public interest and sinking to the least common denominator.

The fourth and final lesson is, "Face squarely the mandates of FERC Order 2000." This order goes a long way toward defining how a wholesale electricity market must be organized. But it is too timid and indirect. Until FERC makes clear that it means what it says, there is too much room for obfuscation and misdirection.

Order 2000 contains a market framework that is working in places like New York and PJM. It also allows for some flexibility. We must have central coordination done in a way that is consistent with a market, whether this is a poolco, ISO, IMO, grid operator or system operator, transco, RTO, or an independent market administrator. The core feature of bid-based, security constrained economic dispatch with locational prices can be found in many existing or announced market designs like Argentina, Bolivia, England, New York or PJM.

What should FERC? Focus on the public interest. The role of the coordination function should be to support an efficient competitive market, while the role of the regulator is to ensure that this is done in the public interest. Like it or not, FERC is in the business of market design, and is the principal participant charged with the public interest.

PJM and the New York markets are the major successes of wholesale market restructuring, and New England was headed in the same direction. We don't want to break what is not broken there, but we do want to move ahead with a clear eye towards embracing the best practices in integrating the operation of the markets. And we have to recognize that this is not going to be easy, nor is it guaranteed. Again quoting from the Northeast mediation report: “Any polemic is directed to - and as a caution to - the Commission concerning those interests who would sacrifice optimal RTO benefits in the long run to exploit more immediate economic opportunity in a sprint.”

As for the Southeast, Midwest and West, we should lay out a mandate for a standard market design based on the Northeast model. Make this the starting point for the discussion. Don’t make the participants go through the delay and agony of repeating bad ideas that have failed elsewhere. Place the burden of proof on other market designs rather than assuming that stakeholder preferences must prevail.

If we’re to succeed, it’s necessary to have a standard market design. I don’t know whether three, four or six RTOs are the right answer, but the way that they’re going to work best within the region and among the regions is if they start with that market design and make it work in their own regions.

Speaker Three

What problems is the RTO initiative trying to fix? The first problem is the discriminatory access to transmission services as a result of operating interconnection investment decisions made by transmission owners who are also market participants, generators, marketers, etc. This problem arises in the US because of vertical integration between transmission distribution, generation and marketing. It’s the source of the independence concerns, or lack of independence concerns that lie behind the interest in ISOs and RTOs. It leads directly to a problem of perceived lack of independence and discrimination. But this is not just an electricity market issue. The same problem arises in telecommunications. The lawsuit against AT&T in the 1970s culminated in the breakup in 1984. It arises today with DSL.

The second problem arises from balkanized ownership in operation of transmission facilities because this complicates efficient scheduling, transactions and the management of constraints. It increases transactions costs and reduces competition. This is also a consequence of the industry structure that we’ve inherited from the past which has had a large number of utilities typically organized in individual states, many owners of transmission capacity and too many control area operators, a point that we made 20 years ago.

It has also led to the balkanized pattern of wholesale and retail market designs and operating practices that reduces competition and increases costs. Part of this is also a consequence of the federal system and the particular split of federal and state jurisdiction that has emerged over the last 70 years that may not be optimally designed in terms of the mix in jurisdiction for promoting competition. We have too many markets.

Finally, a problem that has received adequate emphasis is inadequate transmission investment in the current system. This is not just a problem in the US. Liberalized electricity sectors around the world have failed to develop a framework to encourage transmission investment in the right places, at the right times and efficiently. Why? Wholesale and retail competition initiatives in the US have proceeded without a clear national model for reform, in sharp contrast to countries like Britain, Argentina, Scandinavia, portions of Australia and New Zealand.

In the US, there still isn’t a clear national model being promoted at the federal level for careful consideration. We are slowly moving towards it. As a result, both the Energy Policy Act of 1992 and Order 888 envisioned more limited changes in industry structure, vertical integration but also horizontal integration, mandated no structural reforms and focused primarily on regulatory rules, to try to induce parties to move in directions that would promote wholesale competition more broadly and retail competition in particular states. Unfortunately, these rules were often incompatible with the financial interests of incumbent firms and vertically integrated transmission owners. It's much more difficult to implement regulatory mechanisms when you're constantly fighting against the financial interests of the firms that you're trying to regulate.

The third problem, which flows from the other two, is that the US has failed to adopt a standard textbook reform framework on a national basis. Federalism is a national laboratory for experiments, but this approach reflects a lack of vision or a lack of political will or capability than a well-thought-out effort to experiment with different approaches to introduce competition into electricity markets.

The bottom line is that the traditional US industry structure, primarily built around private, vertically integrated utilities, is not very well adapted to successful wholesale and retail competition initiatives.

There is a common set of basic changes that needs to be made, and some institutions that need to be introduced. Many of these things also apply to telecommunications, natural gas pipelines or railroads. The need to separate regulated monopoly segments, in this case, transmission distribution of system operations from competitive segments or potentially competitive segments , is always emphasized. In the electricity industry, it is the generation of electricity, wholesale and retail marketing and trading opportunities.

The reason for such separation is to resolve the discrimination problem and to create an inherently independent market structure to handle the structural changes that create transmission and distribution system operating entities that have no particular interest in favoring one generator or retailer over another. All regulations required to enforce independence become unnecessary because the structure has been changed to remove the problem.

A second piece is to create a transco/system operator or a transco plus a system operator that spans a region large enough to internalize network externalities. There are different ways to allocate these functions, but both are monopolies initially. The point is to create a transmission network and its operation that spans a geographic area large enough to internalize significant network externalities. This fundamental principle should be used in defining the boundaries of RTOs in the United States.

Another aspect is to create transmission access, wholesale market and congestion management institutions that facilitate wholesale and retail competition and mitigate market power. There is a problem with creating competitive markets because of the balkanized structure of the industry.

Transactions are scheduled on the transmission network. There has to be a balancing mechanism, a congestion management mechanism, a mechanism for acquiring ancillary services and mechanisms for billing and settlements. The market will not create these institutions. There may be different ways of doing it, but there has to be a basic market platform. The creativity that we associate with competition and other markets is going to have to evolve over a longer term. Contractual arrangements, investment decisions, energy management and demand management activities can also impede a thousand flowers blooming on the same network in terms of creating the basic platform.

Since we are still creating monopolies in this system, there needs to be a regulatory system in place. All regulatory systems create incentives. It makes much more sense to think about what the good regulatory mechanisms are that will align the financial interests of the transmission owner and system operator consistent with the goals for this system. This helps with the current challenges of system operations, particularly investment.

How have we gotten to this kind of an organization of RTO? We have to return to the evolution of competition in the United States over the last decade and we haven't had a clear focus on where we're going. We have made a series of compromises to move forward, each of which seems rather pragmatic and somewhat imperfect. The departure from an ideal or close to ideal situation becomes greater. Maybe it is pragmatism at the outset of creating these vague RTO entities, because it seems like that's the only thing we can really do to move forward given where we are now.

We are going to organize the US into four regional networks to be controlled by a non-profit organization without any assets or financial responsibilities. We know that organizations and institutions with soft budget constraints and lack of financial responsibility and market discipline rarely perform very well. There are problems associated with the separation of ownership from control of assets. These problems can be magnified if we end up with a system where they have a hierarchy of these organizations before we get down to the owners, that increases transaction costs and coordination problems on top of incentive problems.

One of the attributes of organizations like this is that they do very well when they are initially set up with high quality, enthusiastic people. But we need to pay more attention to the nature of the institutional creature we're creating and how well it's going to perform in the long run. We used to have to worry about the possibility that organizations with these attributes, but without financial responsibility and incentives would actually reduce the value of existing assets and discourage investment, rather than enhance investments. The worst monopoly to regulate and the most difficult, is the one that can't be held financially responsible for its decisions. Organizations like this tend to be slow to adopt innovations. Examples are the FAA, Massachusetts Port Authority, some turnpike authorities or the New York Port Authority.

FERC should take more seriously the introduction of performance-based regulation of these entities, to induce them to make operating, planning and investment decisions that are aligned with the goals that are established for these entities. This should be a carefully articulated regulatory framework where companies find it in their self-interest to do the kinds of things that public policy makers want them to do.

We do have international experience to draw on to fine tune the structure of independent transmission companies' regulation and the role of third-party initiatives. We cannot give up trying to learn from both the successes and failures in other countries. We should explore more seriously what has and hasn't worked in other countries. England and Wales is a model with a very good organizational baseline. They have been able to accommodate the addition of equal to 40% of the initial amount, and the retirement of an almost equal amount, of generated capacity. Direct and indirect costs, congestion management and the ancillary service costs have all declined. Although there's been the addition of a substantial amount of generation in very different places from the generating plants that have been retired, it's been accomplished with almost no construction of new transmission lines. But when you have an entity that has the incentives and the ability to enhance the capacity of the existing system, it's impressive what can be done without substantially expanding the footprint of the transmission facilities. We can learn from successes and failures, and we need to do that more aggressively.

We shouldn't give up on structural reform. I don't think we can require structural reform in this country as a political matter, but we can encourage it by changing the tax laws and with suitable regulatory incentives. At the very least, we should not make decisions that discourage or preclude vertically integrated utilities voluntarily to restructure to create regional transmission companies that are independent of market participants.

Speaker Four

The system operator coordinates system operations through a regional security-constrained economic dispatch to maintain system balances and relieve congestion. The RTO also should use market mechanisms to support its system operation functions. It would be done in the form of accepting price offers and bids from generators, defining market-clearing prices, and all market participants should be allowed to submit bids. Everyone should be allowed, but no one should be required.

We need to support bilateral and spot markets. The market operator will price imbalance and spot energy at the locational marginal price for each location. The RTOs should make financial transmission rights available for participants. As the RTO handles what are clearly non-trivial issues, forward markets, such as a day-ahead market, may also be added.

Parties can use these financial instruments to hedge for the differences in locational prices. Another basic postulate is that you should not require one of these rights to schedule. This is a basic element of the financial rights model and the market participants can make a decision whether they want to hedge this transaction. The RTO shouldn't be concerned about matching up a schedule with a specific right. The RTO should be into real-time dispatching. Market participants should be able to collect the settlement value of that hedge. In a dynamic system, the participants are better off than having to match these rights to exactly what they're going to schedule especially when they may not know that until an hour ahead. Can a standard model support flowgate rights? It is an open and a hotly debated issue. A system of options will probably reduce the amount of rights available, but that is a decision that will have to be made.

The benefits of standard market design include supporting a flexible spot market. To the extent that you have retail access, that's very important for competition. It is necessary to put the incumbent utility on an equal footing without having this large provider of last resort load hanging over it and having to make capacity arrangements for load that may or may not come back. . Standard market design also supports the creation of trading hubs. And a settlement system should minimize uplift.

A big question is the implementation of this standard market design in a multi-control-area environment. There is the issue of the installed capacity requirement. Is it required and why? Who decides? Are there regional differences? There are regional differences in the amount that you might need. Do you need it only for reliability, or should it be to keep market prices less volatile? This policy decision goes to the issue of the mechanism we are going to use to encourage generation. Also, is the cap needed to support the spot market?

A couple of final thoughts: There is a record that standard market design works. If you have a standard market design, it lets you deal with a lot of seams issues. It does not have to be one gigantic RTO to accomplish the benefits. You can have a different model. It might be a nonprofit model sitting next to a for-profit owner-operator model. They can do their dispatch where people bid, but the market design acting in a seamless manner will let participants transact throughout the whole larger region, which could be larger and many times is either smaller than an RTO or larger than the multiple RTOs. And drawing the artificial lines is really the problem, but you need to do that.

A standard market design resolves seams issues. It allows multiple transmission organization models. Market design clearly is of interest to all market participants. It allows each organization to engage in its own dispatch and avoids the issue of whether an RTO is too big.

But how do we get there? You have to buy into the concept that the same is good. And that to some extent takes a leap of faith. It is a big change from the deregulation and the regional differences that we've seen. In my opinion, when you're talking about the markets within each of the interconnections, you really need to go in this manner. Do we go on a region-by-region basis with multiple meetings to resolve every one of the issues that are common to each organization, and end up with case-by-case filings to FERC? It may be that until you get approval of this design, an RTO and surely a for-profit RTO will be unwilling to spend money for the software design. These things take time. According to Order 2000 by December 15, to be an RTO you need to have a real-time balancing market. However, market-based congestion management is a year away.

Is this really compatible when you think about it? Should the commission look at a midcourse correction? The final issue is did we get it right? Can we implement it right away? That really goes with the issue of what we do with balancing the market. Do we really need to get that on day one, or should we do it as an integrated system?

Comment: I think US regulation really has to start changing the way it conceptualizes how it goes about its business and how best to induce performance that benefits consumers.

Question: As we move toward convergence on a standardized market design and a smaller number and larger scale of markets, should we try to mitigate price volatility in a standardized way or leave it the way it is now?

Response: I don't think there's any reason to be fiddling with price volatility per se for spot markets; it is not important. The job of market monitoring is to identify market failures or market imperfections and performance problems broadly defined, including market power problems and how they might be facilitated by poor market design or detail rules.

Comment: I don't think that FERC can completely or even largely decentralize the market monitoring and market improvement task to market monitors at the RTO or ISO level. FERC itself needs to have the technical capabilities in its staff, both to do market marketing but also to interact in constructive ways with the market monitors in the regions, and be in a position when there are serious problems, to act quickly and decisively to fix them. We do not want to get in a situation again where because of market performance problems we're in a refund proceeding. Whatever the right or wrong is about that, the notion of going back and calculating refunds in a market a year after the fact is a mind-boggling exercise and I think introduces exactly the kind of uncertainty that could well undermine investments. We have to identify the market problems and fix them quickly. FERC has to be engaged and to have the capabilities to act fast to do that.

Question: Although I have some biases in favor of PJM and its ability to operate, I appreciate the institutional concerns you raise about the long term. Are there institutional models or dynamics that would permit the creation of incentives to make non-profit, non-asset- owning institutions work efficiently with long-term viability? Is the combination of these institutions with a governance stakeholder process where asset owners protect their values inconceivable?

First Response: I would predict, even for PJM that starts out with the best cases, that within the next decade, PJM will be a transco. The utilities will divest their transmission assets and they will merge them. The PJM staff will operate them, because it's not inconceivable. It's very hard to provide the kinds of incentives and discipline and reproduction for this kind of entity over the long run.

Since it is conceivable, we shouldn't rule out other alternatives when they have worked in other places and we can have the same market designs in a different ownership institutional framework than in the PJM framework. I'd be inclined to encourage or at least remove artificial barriers in the tax laws and in the regulatory rules to make it possible for companies to form these entities if they want. But if we can create PJMs everywhere, you still have the opportunity for them to evolve into other entities as long as you recognize that PJM is not something that was created last week. It's been there a long time.

Second Response: There is an option of privatizing an entity like PJM or even putting it out for competitive bids or a contract to run the entity by a for-profit organization. We have to be a little bit more scientific about this than we have been and not assume that every institution is equal and marches to whatever the regulators say. We have to recognize that it's not true.

Question: Combining the transport and the merchant function seems a wrong idea. Is combining the ownership and the operation a good one? Do you also want to have it managed and reduce congestion in this joint entity? Take away the congestion market pricing mechanism and substitute uplift, which is really a regulatory activity and it might avoid direct allocation of costs.

Response: There are interesting legitimate questions about how much systems operation is integrated with the actual ownership, maintenance and physical operation of the assets. In England, the regulator has chosen to integrate those and is reevaluated every few years because he has become convinced that there are significant costs from separating them, at least in the way this system is organized there. When you talk to the people managing the system, you can see how they are able to react in very short term to changes on the network, generators calling and saying they really need to schedule maintenance this weekend rather than next week and the ability to basically bribe them not to do that because you have figured out that the congestion costs are going to be too high and you're going to bear those costs.

The question is does it have other adverse effects on the operation of the markets. Again we have different examples. In England and Wales where they basically put those two things together, it has performed well. Congestion costs and ancillary services have gone down, not up. The charges on the network have gone down, not up. We have Argentina where they've separated those functions and the performance there has been pretty good, although the people at the grid company in England and Wales would tell you if they had more control over operations, they could actually reduce costs for Argentina more than they have. We should study the different arrangements to see which ones work.

Comment: I think that FERC actually accomplished a lot. It's a glass half-full, glass half-empty concept. If you look at the Northeast, you've got broad agreement on governance. Everyone agreed to the independent board, and a single, common market. Everyone agreed that it should be done sooner rather than later and that best practices should be incorporated. Thirty-five out of the forty identified practices by New York and New England can be incorporated in the market on day one.

There are some weaknesses. People think standardized means fixed and concrete. Standardized means you start from a model and you grow. I'm totally committed to the concept of growing the market to meet the needs of the parties. For people to say you're going to lock yourself into a standard design is just false, I think. Performance should be the way you evaluate any organization. You see a model that seems to be working, and I hope FERC continues and doesn't despair at the glass being half empty and realizes that in many ways, the glass is full. We can always do a better job, but we shouldn't look at what we've done as a failure at all.

Comment: Where I see a problem emerging, such as in PJM in general, is if the absence of retail competition is accompanied by the absence of any kind of alternative retail procurement program that ends up involving substantial contract cover in the market. If that were to evolve into a market like California's where 60% or 70% of the energy was flowing through the spot market every hour, it could become very problematic. That's both a PJM and a general problem, not so much a failure of retail competition. More broadly, we need to have a clearly articulated retail procurement program if we're not going to have retail competition in which a large fraction of the load becomes the responsibility of retailers.

Response: The large consumers of electricity in PJM do not respond to market prices. That's just the nature of the system right now. I think if you had the situation like we had in California, it would create a real problem.