Harvard Electricity Policy Group
Twenty-First Plenary Session
Meadowood Conference Center
St. Helena, California
January 20–January 21, 2000

RAPPORTEUR'S REPORT*

Session One: Mergermania and Public Policy

New mergers are being contemplated and proposed. Both traditional and new types of consolidations are appearing. Some lack direct physical interconnections. Others are acquiring pieces rather than the entirety of companies (e.g., just the generation or just the distribution assets). Some companies have proposed to swap assets in order to focus their efforts on core activities. In light of all of these changes, what should public and regulatory policy be? A number of questions arise:

- *How should markets be defined for purposes of analyzing market power and contestability? What models can be employed to assure a dynamic rather than static analysis?*
- *Are there problems too subtle for regulators to adequately scrutinize?*
- *What roles, if any, should FERC, SEC, FTC, DOJ and/or state regulators play in analyzing and passing on transactions?*
- *How big is too big?*
- *What remedies are most appropriate to address market power difficulties that arise in connection with a merger or acquisition?*
- *How should issues of horizontal consolidation be addressed?*
- *What is the optimal business structure for a company trying to compete successfully in a competitive market? Is bigger truly better? What advantages, if any, remain in a vertically integrated structure?*

---

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

Speaker One

Mergermania is really an outgrowth of deregulation. Why is it going on now and what is driving companies to consolidate? It is rare that I have ever seen a merger. No matter how they are put forth, at the end of the day there are only acquisitions. Mergers are time consuming; they are culturally disruptive and often don't deliver the value that is anticipated. For that reason, many have stopped trying to do mergers and tried to set up front clear expectations with their consolidation partner as to who is going to be doing what and how quickly. And that is all driven by what Wall Street is demanding of this industry today. Raising the capital necessary to compete in this industry has become incredibly difficult. It is not that the money is not out there, but convincing your investment community about why it is an appropriate use of their funds to acquire assets and/or entities has become much more difficult.

The Street is asking several things of the utility industry today when they propose consolidations. It is imperative to be able to demonstrate a clear vision of what your strategy will deliver. The second thing is how aggressively you are pursuing opportunities. They are looking for sustained growth and sustained penetration into specific markets. The third thing that the Street is demanding of this industry is execution. Value has to be delivered. They understand that this industry is segmenting along various lines and are cognizant of which part of that business you're going to be focusing your attention and future assets on. There is fairly robust growth evolving in energy trading and energy supply. Transmission is viewed as a no-growth market until we do something substantial with how we will treat transmission assets. Distribution is viewed as limited-growth, and retail is viewed as neutral, mostly because of the failures and limited successes in the market, but with a good case having been made that retail is a real growth area. Wall Street seems to be neutral on folks who are proposing to make significant investments in the pure retail end of their business.

There are several areas that people have categorized their acquisition strategy into. The historical view was full integration. Today we are seeing more selective acquisitions. It is based on where in the value chain companies want to play—where are their competencies, what do they think the market will reward them for, and what are they comfortable focusing management attention on. There are two views of that: those who acquire for breadth of their value chain, and those who will buy the unbundled assets to integrate them with their part of the value chain that they are comfortable playing in. There are the players who are buying selected assets only, and there are opportunities to buy discreet assets. No one strategy is correct. It has to be individually tailored.

In terms of strategies, there are mindsets that need to be demonstrated to Wall Street to gain successful investment. These break down along four lines. There are the energy service providers, those who will provide energy in all forms, including based on asset ownership. There are the pure retail players, e-tailers, if you will. We are seeing the emergence of the global merchant. And there is the asset aggregator. This last one is a strategy that leads to a much more deregulated and wholesale supply-side vision of the future.

At the end of the day, what the Street wants is that you be a large, competent, focused company that has optimized its available assets and delivers value quickly. That demands scope and depth in segments of the value chain that demonstrate both portability and innovativeness. It demands a clear vision of the future as to where in the value chain each of your companies will maximize shareholder value.

It also says that traditional methods of operating assets are no longer optimum. No longer is pure reliability of our generating assets going to be the most important factor that a utility with an obligation to serve has to focus on. If we are in merchant plants, then we need to understand not only how to maximize efficiencies, but how to maximize profitability on an asset-by-asset basis. That leads to different dispatch criteria, and to different cultural drivers that need to be learned. It also says that Wall Street is more comfortable looking at people who will focus on regional and super-regional plays than folks who are focusing on global and national plays.

There are traditionally two areas in identifying where the value is created in mergers: cost savings and financial re-engineering opportunities. With deregulation, value creation has blossomed. The consolidation of complementary or overlapping non-regulated businesses provides opportunities for both cross-selling and margin enhancements in the non-regulated segments. There are opportunities to re-evaluate capital expenditures.

Finally, I want to touch on what we've seen in the way of cost savings. In the last 20 transactions in which we've had data available to us publicly, we have observed that the non-fuel operation and maintenance savings have ranged from 4½ to about 14 percent. These are values created simply by consolidation. When we take generation out of that mix, we find that cost savings up to 24 percent are available to be created as a result of the merger. The majority of the savings, particularly in terms of the availability to reduce staffing, comes in the administrative general expenses, which are truly duplicative. Whose savings are those? If regulators insist that too large a portion of those savings belong to ratepayers, mergermania will end. Without mergers, much of that savings will never have been created.

Let me make a couple of predictions for the future. We think that over the next several years we will see a growing trend of utilities and other energy companies, rather than merging, acquiring each other to do asset swaps, service territory rationalizations, cross-contracting to create and unleash value. A bolder forecast is that the traditional energy company will cease to exist. We will see more national mergers and mega-mergers over the next year or so, particularly with Europeans. E-tailers will grab a bigger piece of the business. We will see more consolidation and ourtsourcing of support services, the back office stuff. Finally, we are on the cusp of seeing non-traditional acquirers enter the market.

Speaker Two

We are extremely concerned about a problem that has taken place in telecomm: Competition without competitors. In electricity, we are going from a regulated franchise monopoly structure to a so-called competitive structure. We're in transition. None of the rules are set down. And while we are trying to figure out how to reorganize the industry, everybody merges. So before we get a structure and a set of institutions in place, we end up with very few competitors.

It has always been my belief that the single most important reason driving mergers is market power. None of the proprietary documents that I have seen while participating in state-level merger hearings suggest that the price of the product that they are selling which is to be the beneficiary of this synergy will go down. If you generate synergies and lower the cost of production in a competitive market, you have to lower the price. But they can't write that down, because they can't justify the value of the merger. The fundamental assumption of those mergers is that they are never buying a more competitive market. Of course, we know that in the back room, they are buying a less competitive market.

We think that the electricity market is not functioning very well. Since it has been restructured, there have been price spikes and outages. It has failed to deliver, at the most critical times, price stability or quality. The prudent policy that we would suggest is that mergers between vertically integrated, contiguous utilities should not be allowed. Contiguous companies ought not be allowed to merge because the structure of the industry is very vulnerable.

The analytic framework looks at structure, conduct, and performance. Regarding structure, horizontal mergers get a tremendous amount of attention from the regulators, and vertical mergers do not. Yet, if you look at vertical mergers and vertical integration conglomeration carefully in the literature, there are a set of circumstances under which both the case law and the academic literature say you should worry about it.

The electric utility market is a difficult place to think about having a competitive structure. Supply side is tight, there are long lead times, little ability to expand capacity, you can't store it. Demand side is a problem as well—very little elasticity, long lead times, demand is set by capital structure, weather sensitivity, etc. The transmission network is not a growth area. The electric utility industry has problems in all three areas. Accidents don't just happen. There are structural reasons in this market that these accidents are problematic. These accidents are made worse because of institutional characteristics. Things may improve. But where we are today, there are serious identifiable problems in the market.

What is the policy conclusion? There should be a moratorium on mergers until we know what the industry structure is going to look like. There also ought to be a very clear requirement that you cannot merge assets unless you are part of an RTO. The transmission bottleneck is critical to the functioning of the market. So we have to have those open highways. You have to have open access to the demand.

Let me tell you what a collaborative looks like in one state. In telecomm in New York, there are 400 lawyers in the room representing everybody who wants to play in this industry. They sit down and try and figure out non-discriminatory rates, terms, and conditions for access to the network. It has taken four years to drag one state into open access when there was clear legal authority and a vigorous incentive, which was to get into long-distance.

How can FERC pull the electricity industry into non-discriminatory RTOs with absolutely no incentive? It won't happen. The utilities will not voluntarily give up their market power. It is just too valuable. People do not renounce their property rights when they have so much economic value. FERC should make a condition of the approval of any merger or the granting of any market based rates to be participation in that RTO. Given the problems we have identified, FERC can conclude that mergers and market-based rates in the absence of participation in the RTO are not in the public interest. Further, we suggest that all existing market-based rates should be reviewed if utilities refuse to join RTOs. Only if you have that compulsion will you get people to cooperate in this collaborative process.

Question: Did you say that under the FERC final rule, there aren't sufficient incentives? There is a list of incentives, things you might get if you join an RTO.

Response: Looking at what has happened in telecomm, the bribing in the RTO rule isn't good enough. What you need is compulsion. We suggest that if you want a merger, you have to be in an RTO. If you want a new market base, you have to be in an RTO.

Question: You focus on geographic mergers of vertically integrated companies. But I'm not clear on what you're saying relative to horizontal mergers. You seem to be saying those are okay. Are there issues there?

Response: A merger of two generators, where they own no transmission or distribution assets, is an easy case for anti-trust law. The analysis is straightforward. This is very important in electricity. But I am not going to focus my attention on two generators that don't have any assets to leverage. The thing that has not received sufficient attention in the four years under the telecomm act is that every time you see a merger come down the pike, they do their horizontal analysis but never look at things vertically, and we've ended up with this incredibly vertically integrated industry. Because we have not looked at the geographic and vertical elements of market power in the telecomm industry, we have lost control of the industry structure. That is what I don't want to happen in electricity.

Speaker Three

I want to give you my perspective on the transactions and how they break down categorically, some of the reasons behind the mergers, and some of the regulatory parameters that are affecting how and what kinds of deals are being done.

It is no surprise that 1999 was a year of extremely high activity. There were 30 transactions announced, which is more than were announced in the previous three years combined. Seventeen were traditional mergers, 12 in gas, five electric, which are contiguous mergers. Five of the 30 were convergence mergers, electric and gas. Five involved new entrants into the regulated gas or electric business, and three were mergers of non-contiguous electrics.

Most of you are probably familiar with the five convergence mergers. The one that is of most interest is the Dominion/C&G transaction, which is a large and interesting transaction. You have Kinder Morgan acquiring KN, which I see as primarily a pipeline transaction that also required some significant regulated gas assets. You have an investor group buying Mid-American Energy. Then you have National Grid and New England Electric, where we have one of the first major cross-border transactions involving a foreign company acquiring regulated assets in the United States. Two of those transactions were announced in late 1998—the Scottish Power/PacifiCorp transaction and the National Grid transaction.

These transactions result in enormous economies of scale for these companies and, I think, don't dramatically change the competitive environment within the U.S. PacifiCorp, for example, now has a much larger parent company which can provide it with resources that it didn't have before, and yet the competitive dynamics haven't changed dramatically. Another interesting question to watch is whether there will also be acquisitions by foreign companies of gas companies. So far it has been only electric, but there clearly are major non-U.S. companies that are interested in getting into the gas business here.

When you look at the list of 30 transactions announced in 1999, you will see that a lot of the smaller companies are simply being auctioned off to the highest bidder. We have also seen the first mergers that disaggregated transmission & distribution companies.

Reasons for the activity fall into two categories, business reasons and regulatory reasons. There does seem to be a consensus among many utility executives that bigger is better, that people are going to need economies of scale in order to develop new systems and products, and generally diversify their asset base. Another driving factor from the buyer's perspective is that they have a lot of cash that they have to redeploy. From a seller's perspective, it is a seller's market.

Turning to the regulatory front, the Public Utility Holding Company Act of 1935 has been an important factor in a lot of the activity taking place. Over the last 10 years, there has been tremendous liberalization in the way the SEC has administered the Act. The Act is substantive regulation; the SEC is charged with protecting the public interest. In the last few years, though the SEC has not disavowed its interest in protecting other constituencies, its primary focus has been on the interest of investors, and they have maintained a policy of "watchful deference" when it comes to the FERC, Department of Justice, FTC, and states. They have tried to stand back and not get in the way of other regulators.

Where has this liberalization occurred? One of the most important has been a liberalization of the integration requirements of the Act. Traditionally, when the SEC had to approve a merger, they had to find that the merger or acquisition will tend towards the development of a single integrated utility system. Starting about 10 years ago, they liberalized these requirements. On the gas front, we now have the Sempra/Frontier order, which effectively finds that the entire continental U.S. is part of a single integrated gas system. There is the AEP/Central and Southwest proceeding, which by all accounts will be approved. I think there will be a finding that those two systems, although geographically disparate, are an integrated system.

Another major development is that the SEC has reinterpreted its rules to permit the retention and ultimately the acquisition of gas systems by registered electric holding companies. We have also seen foreign ownership restrictions eased. With Scottish Power, this is probably the first time in history that we have had a major foreign company like that willing to accept the strictures of registered holding company status.

The result of this liberalization is primarily that we've seen more mergers of geographically disparate companies. We have also seen an ever-increasing number of registered holding companies, and convergence transactions for registered holding companies.

FERC has focused on market power problems in the context of divestiture of generation, not mergers. I think this is going to change with Order 2000. There is clearly going to be a greater focus on transmission, although I think it will be more of an evolutionary than a radical change. There is an assumption in the industry that people going in for mergers are going to be expected to comply with Order 2000.

There have been fewer orders on the gas side. A recent FERC order applied the affiliate code of conduct rules that were developed in the pipeline context to gas and electric affiliates in the same system. Under the Hart-Scott-Rodino Act, DOJ and FTC have been involved in these deals. But with the exception of Virginia Gas, there have not been divestitures required. On the state front, there has been an increasing level of sophistication of most state regulators over the last 10 years. They are focused on the competitive retail environment, and are using things like service quality indices to ensure that their concerns are properly protected.

What we will see going forward is further consolidation among gas and electric companies, continuing generation sales and consolidations, businesses defining their roles more as Wall Street wants them to do. We may see some resales, for example, Portland General being sold by Enron after that transaction didn't work out the way they had hoped it would. We are going to see an increase in the international dimension of this industry--further acquisitions in the U.S. by foreign companies. There is going to be a convergence among gas, electric, telecomm, and e-commerce companies. Finally, as people succeed, they will try to monetize some of those investments through public offerings of some of those unregulated enterprises.

Speaker Four

I will speak about merger remedies. I view this issue mostly from the perspective of a law enforcer, not a regulator.

In enforcing the anti-trust law, the Department of Justice (DOJ) has only two choices: Going into federal court and challenging a merger, or not going into federal court and not challenging the merger. I always hear people talk about "approval" by the federal anti-trust enforcement agencies. There is no such animal. There is only suing them or not suing them. Under Hart-Scott-Rodino, there are certain deadlines if you are going to sue. But the practice for the last 40 years has been not to sue. In that case, the word "approval" shouldn't be used.

When federal authorities challenge a merger, the goal is to prevent or undo an ongoing violation of law. There are no social engineering goals. There is no using leverage to achieve some greater good, no matter how greater that good is. There is no possibility under the statutory scheme of imposing conditions on a merger that isn't challenged. Of course, if a merger is challenged, there may be a consent decree and the consent decree may look like regulatory conditions, but you have to challenge the merger and prove that it is illegal in the first place in order to get any relief.

In terms of mergers that are challenged, by far the biggest category consists of unconsummated transactions where the parties have agreed in advance to resolve DOJ's concerns through a consent decree. The centerpiece of this decree normally is the divestiture of assets. As the Supreme Court has remarked, divestiture is the preferred remedy for an illegal merger or acquisition. Anti-trust remedies have to be implemented and administered by courts. The court which imposes the remedy has to administer the remedy, so DOJ has very limited control over what the remedies are.

There are also procedural requirements that are important. The Tunney Act regulates everything that has to do with a settlement in an anti-trust case, and that includes the consent decree process. It requires DOJ to publish what is known as a Competitive Impact Statement, which explains the basis for its challenge to the merger and why the proposed decree solves the problem. Anybody can file comments, particularly about the adequacy of the decree. Courts may--although they never do--hold evidentiary hearings. The decree is imposed only after the court decides that it is in the public interest.

The remedies that DOJ normally seeks and the courts impose are structural—i.e., remedies that address the incentive to act anti-competitively or the ability to do so, or both. There is little precedent in merger cases for structural remedies other than divestiture. Some other kinds are structural and potentially appropriate. One type would be one that alters the control over assets rather than the ownership. A good illustration is the use of an RTO to remedy a vertical control problem between transmission and generation. Another kind of structural remedy would eliminate a competitive bottleneck. For example, you could remedy the market power problem from an electric utility merger by building transmission, and it might be efficient to do so because that may open a market up to competition.

Conduct remedies simply outline a list of specific actions that firms might otherwise have taken, but can't because they are declared to be contrary to a court order, and if they do it, they get held in contempt of court.

There isn't much history of significant penalties being imposed for violations of decrees in merger cases. But DOJ had a big victory recently in the District of Columbia. A company made a rather convoluted argument about why it was allowed to do something that the decree clearly prohibited. They had to pay a big penalty.

Structural remedies are preferred because it is widely believed that addressing the incentive and ability to act anti-competitively is the most effective way to solve the competitive problems created by mergers. I have a lot of doubts about any remedy that asks someone to act contrary to their self-interest. When you do that, you have to have a cop looking out for violations, and sometimes distinguishing the good stuff from the bad stuff is a tricky business.

Structural remedies are also in the spirit of anti-trust. This goes to the point about the difference between law enforcement and regulation. Anti-trust is nothing like traditional economic regulation, which is all about conduct rules, continuing oversight and, traditionally at least, the setting of prices. Anti-trust law maintains a presumption against market intervention that has to be overcome.

Anti-trust law avoids continuing oversight by the courts, instead opting for fix-it-and-forget-it remedies.

The role of conduct remedies is limited. There are exceptions. There is one where a conduct remedy was used as a transitional device, and I think was successful because the transition was completed. In several cases, conduct remedies were proposed or even implemented by the merging parties, and DOJ did not think they were adequate. One was a hospital merger in which the parties proposed to provide wonderful programs and not increase prices for a couple of years. This was inadequate. Two years is not forever. DOJ thought prices would fall if the merger didn't take place, so not raising them is not such a big deal. As a general matter, DOJ doesn't want any kind of price regulation, even if it is self-regulation. However well-intentioned, this in itself could create substantial inefficiency. In another case, the merging firms tried to create a replacement competitor, but they did it through a contract that could easily be modified or rescinded without anybody's permission. The one area where some kind of contractual or conduct remedy might be appropriate is where the merger is a problem for a small period of time, for example, 20 hours a year. In that case, a structural remedy might be overkill.

The calculus changes if a regulatory agency has imposed a remedy. This does not preclude a challenge to the merger by DOJ. But a court may defer to the agency's expertise. In Dominion Resources' acquisition of Consolidated Natural Gas, FERC found a competitive problem and agreed to a code of conduct remedy. Subsequently, the FTC negotiated a consent order calling for divestiture of two large gas-fired generating plants.

The bottom line is structural remedies yes, and conduct remedies not quite never, but hardly ever.

Discussion

Question: The first thing most merger partners do is commit to register under PUHCA. So I wonder if PUHCA is still the issue that it used to be and whether we should be spending political capital to do something about it.

First Response: We should be trying to do something about it for two reasons. One, in almost all respects, it is unnecessary regulation; and two, there are many things that either are not being done or are being done in ways that are perhaps less efficient than what might otherwise be did we not have to deal with PUHCA now. Registered companies are regulated with respect to acquisitions, diversifications, affiliate transactions and financing. Taking financing first, it seems absurd. The SEC should be passing on the substantive merits of securities issuances by utility companies. Diversification has, to some extent, taken care of itself as people learned that utilities were not necessarily good at diversifying into drug stores and real estate. What we are not seeing is mergers of significantly disparate electric or gas utilities. Why should a company have all these divisions? Why shouldn't they be able to have a holding company that effectively isolates each of the regulated utilities?

Second Response: You're always better off having law on your side than policy. The SEC could have been implementing PUHCA in a fashion that is pro-competitive and pro-consumer, but it's not. So, in exchange for taking that function away, I want something in its place. I find it to be a very useful bargaining chip.

Third Response: I have significant doubts the Act can be implemented in a pro-competitive manner. If there are competitive issues, the Act does all the wrong things to deal with them. It doesn't address any competitive problems that might possibly exist. Integration may be the worst possible thing for competition in some cases.

Question: There is a widespread notion that you have to get at least five million customers if you want to survive, and I even hear that the number is up to 20. But doesn't it depend on what business you are in--generation, retailing, marketing, etc.?

First Response: I think you are right. The notion of a 10 or 20 million customer business starts with the presumption that you remain integrated both vertically and across the value chain. Having that many customers allows you to implement and maintain the kind of infrastructure that we've not had in this industry before. It's difficult to justify providing the kind of customer care that we're foreseeing if we're going to be selling multiple products and in multiple lines of business. Also, you have to be careful how you count customers. We are not talking about 20 million separate households. We are really talking about sales channels into a number of households that aggregate 20 million.

Second Response: If everyone has to have 20 million customers to be big enough, that's a highly concentrated market at the national level. There is a new theory that was developed to defend Microsoft called "serial monopoly." It says that competition is not about two companies being in the same market at the same time, but about one company owning the whole market and then getting replaced in a certain number of years. That is the kind of thing you need to justify the kind of concentration occurring in this industry.

Question: You said that price spikes are an indication of market power. I'm wondering why you believe that, as opposed to the possibility that price spikes are just a natural economic phenomenon when supply and demand are temporarily out of balance.

First Response: We looked in detail at the analysis of the price spikes, and people who conducted studies of Ohio and California did ask that question. If you look at the markets where those price spikes took place, individuals were exploiting the weaknesses in those markets to drive the price up. The problems in those markets are structural and institutional. They won't go away over time; they are not just accidents. The order of magnitude of the spikes is unlike anything else you see in other markets. They are not just seasonal highs and lows. So, they require a public policy response. One of our recommendations is one of burden of proof--that anyone who contributes to the tightening of a market, and then subsequently profits handsomely by the run-up in price, has the burden of proving they didn't manipulate that market.

Second Response: I have no doubt that there is room for the policymakers to get involved in these price spikes, although I may favor a different intervention. I think the main thing is that we are still not making any attempt to use efficient prices to clear markets. If we did that, the price spikes wouldn't be nearly so big. This is a hard thing to get regulators to change the policy on.

Comment: I refer to your comment about creating competition without competitors. There is the argument that the more competitors we have, the better, no matter how much they cost. The other way to look at the problem is in terms of institutional problems and design issues, and trying to make entry easier. You can't just count how many competitors there are; you have to look at how the system works. My view is that the institutional design questions are much more important than counting the number of competitors.

First Response: The point I was trying to make is that what we shouldn't allow to happen is, after we are done working on the institutional design, to be in a position where we have no competitors. Counting competitors is always important in merger and anti-trust analysis. In fact, if you look at the guidelines, that's where it starts. In telecomm in New York, contiguous entities were allowed to merge, and the best potential competitor disappeared. Then you have to go back to regulation.

Second Response: In electricity generation, I don't think economies of scale are going to keep us from having a lot of competition, except in certain unusual parts of the company, perhaps, like peninsulas or islands.

Comment: It is transmission and distribution where there are substantial economies. This comes up in marketing, particularly in the context of delivery to retail customers. The cost of serving people is relatively low, and then the marketers come in and say they can't compete against that. Paul Joskow argues that you can end up with a business that you can't survive in without subsidies from regulation, because it's so cheap to provide the service that there's no margin to make. There are no barriers to entry; it's just that you come in with a higher cost structure.

Response: I'm not sure I agree with that premise. We are seeing more and more virtual retailers, where the cost of market entry is very low. The market is becoming more comfortable with e-tailing.

Question: Do the states have any role or any authority to require participation in RTOs as a condition of a merger? If so, when would that become an issue, given that the FERC order didn't define region and scope?

Response: If the state has authority and concludes that the public interest would not be served by the merger if the cost to control transmission assets becomes a bigger bottleneck or creates anti-competitive potential through market power, then they should say no and use that as a lever to try to accomplish a bigger goal. The difficulty is that states are not markets. If you conclude that participation in an RTO is critical to allowing power to flow into the state to protect the public interest of consumers in that state, you ought to say no and make them negotiate with you. The presumption is that you want to separate transmission from generation. It is helpful to get regulators and public policy officials at every level saying the same thing.

Question: If you are in a state where there is no RTO, and a utility wants to merge with someone outside the state, what should regulators do?

Response: This raises the question of whether you can do something indirectly that you can't do directly. If the company is vertically integrated and the concern is that there be retail competition, FERC and the state commission could find ways of collaborating. The real question is what interest the state has.

Question: FERC has expressed concern about convergence between natural gas and electric. Where are the economies of scale in back office operations, and to what degree does convergence in those operations raise problems that lock the retail market up and make it less accessible to competitors?

First Response: I don't know what people mean by convergence. With an electric utility buying gas assets, where there is no integration of any functions, it is just a commodity, not convergence. The Internet destroys all middlemen. There are tremendous cost savings there.

Second Response: Gas and electric mergers raise some competitive issues because gas is fuel supply for generation. Or you might have an issue of the fuels themselves competing in the downstream markets. If you don't have a problem in either of those ways, it's unlikely that you have much of a competitive issue with this and it is unlikely that you will see anti-trust action involved.

Question: First, there was a statement made about mergers being attempted by market power. If so, why would regulators encourage the divestiture of generation? Why would they accept huge premiums above book value? Second, is the sort of bidding where we're bidding all our capacity, but at different prices, contributing to the tightness of the market?

Response: Divestiture is a good idea since it severs one of the critical links that is leveraged in these kinds of markets. Recovery of assets above book has nothing to do with market price. It has to do with recovering assets for captive ratepayers who didn't have a chance to vote with their feet in the past and need to have as much money in their pockets for the future. With respect to bid price, certainly you have to recover your cost of operation. You should be forced to bid at exactly the price that covers your cost.

Question: Have many things that have been proposed in regard to mergers not happened, and to what extent was it because the parties had different perceptions of how big the pie of savings was and who was going to get what share, the public versus the shareholder?

First Response: I think the experience has been that companies have, during the due diligence process, underestimated the potential for savings and grossly overestimated the speed with which they could be achieved. But the markets are demanding that the value be recognized earlier, so it's dropping to the various bottom lines quicker.

Second Response: Due diligence documents, unfortunately, rarely get into the public eye, but they are honest numbers. In California, the achieved gains were twice the projected gains in half the time, so ratepayers ended up with about 15 cents on the dollar of what they deserved.

Question: Are expectations changing the pace of mergers?

First Response: There are a couple of factors. One is, what is the company projecting in the first place? Who takes the risk of the savings not being achieved? That is where a lot of states say, This is your justification, put something up front. Second, how much? That is often difficult to determine, but if there are savings over and above, some of that is going to be recaptured. I'm usually more concerned that the benefits won't be achieved than about whether or not there are more benefits out there in the future.

Second Response: I agree that ratepayers shouldn't pay for a failed merger. But if there isn't much left at the end of the day for the companies and their investment bankers and lawyers, they're never going to start the process in the first place.

Session Two: Are We Facing a Capacity Crunch?

Many commentators and participants in the electricity market are raising concerns that we are not building new generating capacity and associated transmission in sufficient quantity to meet growing demand. Indeed, some argue, that lack of capacity has led to a decline in the robustness of the wholesale market. Are these observations valid? If they are valid, is that the case for the nation as a whole, or is it limited to specific regions? If the latter is the case, which regions? In a competitive market, how do we assess threats to long-term reliability? Who, if anyone, should have the residual obligation to build, or can we fully entrust long-term reliability to the market? Are there inherent barriers to entry, or to the attraction of capital, that effectively preclude placing full faith in the market? Are we endangering long-term reliability by not providing sufficient incentives for demand-side participation in the marketplace? Regardless of the nature of barriers to new investment, how do such uncertainties as the availability of transmission capacity, the pricing of grid-related services, the actual management and operation of the grid, and the lack of a uniform national transmission pricing scheme affect decisions about whether or not to invest in generation? Similarly, are the market rules sufficiently clear that potential investors are not deterred by substantial uncertainties in the marketplace? If the rules are not sufficiently clear, what areas require more definition?

Speaker One

I've been asked to share some views on transmission and generation adequacy in the Midwest in the context of the fundamental question, Is this something we should be concerned about, or does the market work? The answer is, it depends on a lot of things. The bottom line is that I believe the market can work and, in fact, has worked in the Midwest to develop new generation in response to the price spikes there. I do believe we are going to see greater price volatility than exists currently, but that may be unacceptable from a political and social viewpoint.

This is a product you can't live without. Average residential consumers can’t change their demand that much. I always think about the single mom with two kids that she has to feed at dinnertime--she is not going to be able to adjust her lifestyle too much to meet the price signals she is getting. And on a larger scale, nobody would tolerate downtown San Francisco shutting down because of a price spike. The market sent a signal, but it was not one we wanted to hear.

I have been asked to talk about the summers of 1998 and 1999. The electric utility industry never considered June a hot month, but based on the past two summers, it is definitely becoming a summer month. A bunch of units in the Midwest were down for maintenance, and an incredible confluence of events--intense storm conditions along Lake Erie, lightning that struck a nuclear power plant, a tornado that hit a major transmission line connected with that plant. There was curtailment of interruptible loads, appeals for conservation.

FERC prepared a report in the summer of 1998, and the Ohio PUC also prepared one, at the request of the legislature. The FERC report found that this was an isolated event, a result of an immature market. The Ohio Commission took a less rosy view; it saw conditions as right for price spikes to happen again, and as occurring because of several structural problems—the thinness of the market, the lack of price transparency, the lack of a reliable futures market and, in the Midwest situation, the lack at that time of any RTO.

From a price point of view, things were actually worse in 1999. Generation went surprisingly well, but market prices climbed to even higher limits at some points than they did in 1998.

What does all of this mean for the future? In the Midwest, generation reserve margins are significantly down. The age of generating plants is high. The median age of plants is 20 to 29 years, and some that are running are 40 and 50 years old. So the existing stock of generation is wearing down. And new environmental laws are going to hit the Midwest in particular.

The good news is that we did see an almost instantaneous response from the market. Within months, there were applications for more than 1,000 megawatts of new generating capacity to be sited in Ohio alone--almost all, interestingly, to be fueled by natural gas. Subsequent to that was another round of filings for an additional 2,200 megawatts of capacity planned to be sited in the Midwest. So in fact, as a result of the '98 and '99 price spikes, the Midwest has seen a great increase in new generation to be sited. We don't know how much of that will actually be sited, but it's a good sign that the market has responded.

But all that said, the barriers remain huge in the Midwest. There are two competing RTOs, the Midwest ISO and the Alliance RTO, both of which now have been approved in one form or another by FERC. Neither of those represents the size of a reliability region, so there is no one RTO of sufficient scope and size to embrace a working functional market. This isn't a debate about ISOs or transcos; we are beyond that debate at this point. There is no price transparency in the Midwest. There is no organized power exchange. There are none of the institutional foundations such as PJM or NEPOOL. By contrast, all of the utilities are operated as autonomous islands, with virtually no planned regional construction, no coordination of flow issues and very little sharing of capacity. On top of that, there are significant problems with vertical and horizontal market power.

FERC's Order 2000 is a huge step forward but, assuming that that helps to fix the RTO boundary problem, the seams issues, there are remaining problems. All of Ohio's new capacity is natural gas-fired. What does that mean relative to price volatility? The concept of energy security and diversity seems to have gone out the window, at least in the Midwest, and a huge slew of environmental laws is hitting us. Ohio is to have full competition starting January 1, 2001--no pilots, no phase-ins. So there is pressure to get these issues right. There is the incentives issue--there is a mismatch between FERC pushing for incentives and the fact that the return on transmission rate base is primarily in state jurisdiction since transmission itself is in state rate base. So FERC can push for incentives, but if the states are not on board or are doing something different, most of the investment still lies within the retail rate base and not the wholesale rate base.

In conclusion, my answer to the dilemma is twofold. On one hand, the market is working in the Midwest. There is new generation, but it might lead to some results which may not be tolerable from a political or social point of view. FERC has done a lot of very good things to help create generation, but there are a lot of off ramps that can trip us up anywhere along the way. It's going to be a huge challenge, and I worry about the fact that the Midwest doesn't have the institutions that some other parts of the country have to deal with some of those issues.

Speaker Two

What is adequacy? Basically, it means that we have enough generation and transmission to meet projected customer needs, plus contingencies. Long term adequacy and security both complements and substitutes. Generation and transmission also are not just complements, but substitutes as well. If you have more transmission, you need less generation and vice versa.

Why are we studying adequacy now? First, adequacy levels are declining. Second, there are enormous changes underway in the bulk power industry. We are unbundling generation, transmission and system control; the RTO could be transmission and system control, or it could be an ISO that is just system control. Each of these industrial sectors will have different economic incentives, which further complicates things. It is unclear who is responsible for what. We need to get economic incentives to loads from real-time prices and the sale of ancillary services. Regulator roles are unclear.

Transmission capacity has been declining for at least a decade, and it is projected to decline further. So if we think we have insufficient transmission resources today--which we probably do--it is only going to get worse. It is similar with respect to generation capacity. Capacity reserve margins are going down, and the utility forecasts show further declines.

The key issue in terms of generation adequacy is whether it is a transitional issue or a long-term issue. I think it is transitional. The problem in the short term is that most retail loads do not face real-time pricing. One of the main problems in the Midwest in the summers of 1998 and 1999 was that retail load faced traditional embedded cost prices, so they had no incentive to respond when the price spiked at $1,000 and $5,000 per megawatt hour. Related to that is the fact that most utilities still have a retail monopoly with an obligation to serve, so they felt they had to buy resources at almost any price. Finally, a more subtle issue is that where we have ISOs, there are still some problems with the intra-hour balancing markets. PJM and California calculate prices every five or 10 minutes but only settle on the hour, so there are opportunities to game the five-minute price versus the hourly price.

In the long term, the solution is a reliance on markets. I think we are going to move away from a requirement to have minimum planning reserve margins, and will let markets decide both on energy and on capacity. If the regulators try to interfere with capacity markets by establishing minimum planning reserve requirements, they are going to screw up energy markets.

There are two primary ways that we can maintain generation adequacy. One is the use of markets where spot prices send signals to both suppliers and consumers. It tells suppliers what to do with generation in terms of retirement, life extension, repowering and construction of new units, and it tells customers when they ought to be using electricity and how much. California does this. The alternative is a traditional system where an RTO or regulator does loss of load probability calculations and comes up with a minimal planning reserve requirement. That is what we did in the past, and is still done in PJM, New York and New England, although my guess is that eventually that will go away.

I am not suggesting that we make real-time pricing mandatory for anybody. What I am suggesting is that regulators insist that customers have the option of real-time pricing. You don't need very much load facing real-time pricing to have an enormously beneficial effect. If you look at the times where prices get really high, the supply-demand disequilibrium is very small--on the order of two percent. So if you get five or 10 percent of the total load facing real-time pricing, that alone will do a lot to help all customers. It will suppress demand at times of high prices, which will pull peaks down. It will also increase demand at low prices, which will tend to pull prices up. So the very high price volatility that we have been seeing the last couple of years will be dampened.

The two approaches, reliance on markets verses mandating minimum reserve requirements, will have substantially different outcomes on the markets. If we mandate minimum reserve margins, we will have higher average energy prices. We will have lower prices during peak periods and less price volatility. We will have lower customer load factors and more peaking capacity than if we relied on markets to make these capacity expansion decisions.

Generation adequacy is a critical restructuring issue. There are two ways to maintain it: Rely on markets; and continue the practice of centralized determination of minimum planning reserves.

Transmission is much tougher. We can't easily control transmission flows. We basically have free-flowing transmission lines. The flows on one element affect the flows elsewhere. With respect to new construction, there are large economies of scale and scope. Finally, transmission costs are almost all capital and hardly any operating, which means it is hard to design efficient prices because once I have made the investment, there are no marginal costs left to collect from customers.

RTOs represent an important vehicle to help the transmission planning process, but are not going to solve the problem alone and in some respects may make things more complicated. We have uncoupled generation from transmission and since, to some extent, transmission planning requires knowledge about generation, we have to wait until the owners of these merchant plants announce their intentions regarding building. The RTO process is participatory, which is a very good thing, but it takes longer. And you need cooperation and coordination between the RTO and the transmission owner.

Congestion pricing is essential for operations, but won't be enough alone. If I have constraints between the West and East, with lots of cheap generation in the West and some generation in the East that is more expensive—if I find a way to relieve that congestion, the price is $24. everywhere. With congestion, the price is $20 in the West and $30 in the East. So relieving congestion doesn't benefit everybody. So some people will want to make those kinds of investments, and others will oppose it because it will hurt their market position.

Another complication is that it is tough to separate transmission requirements for reliability versus those that are desirable for commerce. Part of why this is important goes to eminent domain. It's pretty straightforward to make a case for eminent domain if you have a reliability concern, but it's tougher if the concern is primarily commerce.

These are some transmission pricing issues that need to be dealt with as we think about investment and planning. Users can't withhold rights to transmission. The system operator has to be the only one able to determine what the transmission rights are and set payments both for losses and congestion. By the same token, the RTO cannot profit from congestion. If it is allowed to keep congestion rents, then it will have an incentive to create a congested system, and what you want is the opposite. Transmission pricing is complicated because most of the costs are sunk, but you still have to recover those costs, so you need an access charge to cover fixed costs and locational prices to guide the locations of new transmission and generation.

There are many unresolved transmission planning issues. One is how to ensure that non-transmission alternatives are considered. California has an intriguing approach with a two-phase planning process--first a traditional process that comes up with transmission projects and price tags, then the ISO puts out a request for proposals for lower-cost alternatives. More fundamental issues are how to decide what are appropriate transmission investments, how to give the RTO incentives to make those investments, and how to benefit transmission investors if the investment eliminates congestion and, therefore, the opportunities for congestion payments.

We haven't invested enough in transmission over the last several years, and need to invest more. Why haven't we done that? I see three classes of obstacles. One is the traditional public opposition to the construction of new transmission lines—the Not In My Backyard syndrome. The second is the transitional state of the electricity industry, where many utilities aren't sure what business they are in, so they are reluctant to make investments because they are not sure whether they are going to remain regulated or be competitive. The third is inadequate financial incentives. We need to figure out which of these obstacles is the most important so that we can solve the right problem.

Speaker Three

California generates about 75 percent of its electricity and imports 25 percent—14 percent from the Southwest and 11 percent from the Northwest. There are problems with both of these. The power from the Northwest is sometimes not available in August and September, when the fish are running. The lines coming in from the north were less than 70 percent utilized when there were heat problems. Power is also being moved north out of California--so the generation that California brings in is being gobbled up, and may not be available to California.

These generation problems are actually worse in the rest of the country than they are in California. The country is in transition, with population moving to the South and West. The Southwest has a worse capacity reserve problem. NERC has concluded that the Southwest, California and Mexico may not have adequate resources to cover a heat wave. ICF Kaiser has suggested that demand growth in the West is outpacing supply additions. The U.S. Department of Energy's draft report suggests that resources are inadequate nationwide.

Looking at daily peak loads in California from June 1998 through October 1999, there were four heat storms, a heat storm being defined as three days of hot weather in a row. There had always been an assumption that when California was hot, the Southwest and the North were cool, since importing was never a problem. However, an analysis found that there is a strong correlation between heat storms in California and in the

Southwest and Northwest. In each of these situations, there were Stage Two alerts, and that was after curtailment. For nine months of the year, California needs a maximum of 30,000 megawatts. For most of the rest of the time, 40,000 is good. Heat storms bring it up to 45,000.

Looking at price levels during a day in 1999, for a few hours, the price goes very high. Ninety-five percent of the time, the price is under about $54, 90 percent of the time it is under $45, 70 percent it is under $31.

Is new entry cost-effective in California? It has been estimated that a new combined cycle plant will need to receive $80 to $100/kw to cover total costs. New generators would have lost money in 1998. In 1999, a new efficient combined cycle plant might have covered its cost in Northern California. Ancillary services add about 11 percent to the market, although that is now under 10 with some good work by the ISO and reliability must-run contracts at 8 to 10 percent. The question has been raised whether all 42 of the power plant projects currently in front of the California Energy Commission for siting will be constructed.

No state agency has sole responsibility for generation adequacy. Market simulations are being used to identify supply-demand shortfalls. The Energy Commission is informing agencies and market participants about what's going on, starting public debate over options and priorities, coordinating responses to modify market rules to enhance market responses, and monitoring the situation to identify contingency plans.

What actions are needed? We need to enable users to reduce consumption through time-of-use meters, information about prices, marketers' willingness to offer variable rates. We need to allow commercial and industrial customers to sell their loads for compensation. That requires the development of load-reduction compensation protocols. We need voluntary load reduction. That requires governmental urging. We need education of the public so that they can run their washing machines at night or early in the morning. We need to find existing but underused generators, and we need to reach a regional solution. If California starts plans to solve what may be a problem, and Las Vegas is growing at 8½ percent a year in electrical demand and not building power plants, it may not be as successful as hoped.

What is happening? The California ISO is developing protocols to allow load participation, i.e., demand bidding, in the ancillary services market. The hoped-for potential is a couple of thousand megawatts by the summer of 2000. They are working on grid planning to allow demand-side management and distributed generation to compete, but that's a longer-term prospect. The utilities have load curtailment advice letters with the PUC, aiming at summer, 2000. The PUC, which does rate-setting in California, is looking at tariffs that will encourage demand responsiveness. The PX is looking at the self-provision of ancillary services. Of the 42 cases I mentioned, 12 have actively filed and are going through the process at the Energy Commission. The Energy Commission is working on streamlining that process. It is continuing its supply-demand resource analysis. It is working with the Air Board to assure that these plants can be built, and it is looking at, among other things, inter-modal trading protocols using transportation savings for stationary sources. It is trying to coordinate its process with EPA's.

There will be a need in the new market for supply adequacy indices against which to measure the availability of, and potential shortfalls in, generation reserves over time. This is needed by the ISOs and other entities that control the market; they need indicators of availability for reliability purposes. It is needed by private developers, who need the signal of how much, when and where. And there has to be a congruence between design and operation. California and the Western interconnection will have to view reliability not as something that calls for a study on how much you have to increase generation or transmission, but as an exercise in balancing supply and demand, and that's a major new paradigm.

Speaker Four

Are we facing a capacity crunch? And can the market effectively respond? A lot of that depends on a variety of factors.

Key factors include open access rules, the theory being that the more open and non-discriminatory the access rules, the more interplay between regions, enhanced trading opportunities between regions that may not be taking place today where you have artificial bottlenecks being created by vertically integrated companies and some of the institutions that continue to exhibit preferences to the incumbents. If we were to open the market more fully, less new generation might be needed.

Another factor is market structure, which goes less to generation adequacy than to lowest-cost type solutions as we begin to expand and build up generation to meet growing demand. The more centralized the market, the less developed the forward market is. We've seen that in places like the U.K., and the high rate of cost of capital for new generation where you don't have a developed forward market.

Transmission interconnection gets to demand in a certain region. The more thorough and complete the retail access rules, the better price signals consumers are receiving--particularly large commercial and industrial customers who are able to effectively respond to price signals—and the less need for peaking capacity. On merchant ownership, we clearly see a paradigm shift, with generation moving from rate base to merchant ownership of generation.

On open access rules, Order 2000 does a very good job of articulating the continuing problems in the marketplace, the significant residual discrimination that continues to exist because of preferences for utility uses of the transmission system. Another problem we're going to have to grapple with is the perception on the part of many that it's still the incumbent club determining the reliability rules, and that has a disproportional impact on new entrants, resulting in artificial bottlenecks being created and the need for generation perhaps being identified in places where it wouldn't be if we had more robust markets. So eliminating preferences, making the wholesale system more open, will reduce the need for new generation.

On market structure, centralized markets dry up liquidity in forward markets. And without well-functioning forward markets, the ability to price forward and to price uncertainty increases the cost of capital, so we're not achieving the lowest cost solutions in new generation in regions with more centralized markets.

It is important to have timely, predictable interconnection. Vertically integrated utilities, while they may be a disappearing breed, still exist in fairly large numbers and will continue to have a stake in frustrating interconnection. That is going to be a significant issue as there clearly is a need for new generation. We also need to look at permitting and siting processes, and make sure that they are understandable and expeditious. In some parts of the country you can get this done in 120 to 180 days, in other parts of the country you're lucky if you get it done in 18 months.

On retail access, DSM can reduce the need for new capacity. On merchant ownership, there are almost across-the-board higher availability rates for new merchant plants, and I think we'll see that also with divested plants transitioning to merchant status. That will add to reserve margins, again reducing the need for new capacity.

Is there anything we can learn from the gas pipeline restructuring experience? In looking at capacity utilization of the U.S. interstate pipeline industry before and after restructuring, in 1987 pipeline load factors were around 68 percent and in 1997 they were up to about 77.5 percent, so clearly the existing assets were being more fully utilized. Gas storage utilization is very much the same, up 73 percent from '85 to '97. Was this in part the result of capital investing increasing in pipeline assets? Net pipeline asset investment actually leveled as optimization of the existing assets kicked in. Transportation volumes increased from 1989 to 1997 by about 33 percent. Gas consumption over that same period increased by 15 percent. I think the difference was greater connections in the marketplace, allowing natural gas to move over more than one pipe. So both competition and optimization of existing assets kicked in. And there was a significant increase in assets early on, '89 to '93, but there has been a leveling of assets in active service. So existing assets were optimized, which obviated the need for new investment that might have been contemplated before markets opened.

In summary, fully open markets will enable lowest-cost solutions to the supply and demand balance. They also will perhaps significantly reduce the need for new capacity. The big question is, Are we creating markets that will rise to the occasion? I think we will see a lot of sub-optimal investments made in generation unless we begin to address some of the issues which I've mentioned.

Discussion

Question: How good of a job are we doing, and what can we do differently, when it comes to providing incentives for proper conduct through congestion pricing?

Response: Avoiding congestion and congestion pricing are completely compatible. If you don't have congestion pricing, then it becomes too much of a centralized engineering determination of where to make the transmission upgrade, whereas if you have congestion pricing, and you can see how many hours a year and how big a price difference there are on the two sides of the constraint, then you know how much it's worth to relieve that congestion. So the two go hand in hand.

Question: Wisconsin has a problem with transmission siting, since a lot of its transmission has to start in one state and finish in another. What is your take on FERC jurisdiction for siting or need determination for interstate transmission?

First Response: Federal siting authority, when it comes to eminent domain for transmission, is not the answer because it certainly hasn't been the answer for gas in the last few years. Whether it helped in the beginning can be argued.

Second Response: There is an impression that the state regulators are going to just say no if it doesn't benefit their state, and that FERC would take a less parochial view. I can think of a case in which a state commission voted for a project that was of marginal benefit to their state, while the majority of FERC commissioners voted against it. So it's not that simplistic as to how people are going to come out on these. It is a good argument for regional coordination.

Comment: I would caution against taking away need until you have a competitive market. California has more demand in San Francisco than can be handled, but the city will secede if you build another transmission line across the Bay. But a regional solution, with Oregon, Nevada, Washington and California deciding on a regional basis that you have to put a transmission line into San Francisco, isn't going to solve the political problem any better than California alone.

Comment: The marketers see themselves as new kids on the block. But they have the same right of participation as anyone. So if there are flaws in the system, it isn't helpful to blame it on discrimination on the part of IOUs.

Response: IPPs have made progress in some of the historical institutions. But it doesn't matter how big you are or what your market cap is; if you've got road blocks, whether it's institutions or companies that have the ability to frustrate interconnection, those are real.

Question: A centerpiece of every retail restructuring proposal has been a rate cap. That means that regardless of what you do on the FERC side, the utility is spending shareholder money. And that is a huge disincentive to invest, both in new lines and older infrastructure. Is there a solution?

First Response: The states are going to have to get real. If they really want transmission, if they really want to deal with congestion, they're going to have to recognize this opportunity to get rid of caps.

.
Second Response: In my state, rate caps were as much, if not more so, pushed by the IOUs as by the consumers. So to complain about the rate cap and then go to FERC and say, we want incentives, but the state regulators are in our way, is a bit disingenuous in terms of the whole process. The other issue is the fact that the money is in state retail rate base, even without a rate cap. So there is a mismatch between the entity driving the incentives and where the money is to effectuate those incentives.

Question: I question whether you can solve this problem through incentives. Many transmission utilities have effective discount rates of 15, 20, 25 percent. When you look at how they value money across time in the context of stranded costs proceedings or rate cases, look at length of amortization, there is so much uncertainty that five or 10 years don't have a lot of value. And Wall Street is not excited about transmission-related investments. Is there much we can do with existing entities to get those types of investments, or do we need new entities that are systematically structured to care about long-term, higher debt leveraging and political controls that are purely focused on the long term?

Response: We can't be intellectually dishonest when we try to start balancing the puzzle. We have to make sure that if we say we're giving them the ability to earn, that we do.

Question: Generation and transmission are a trade-off, and you can still, at least theoretically, finance regulated transmission in different ways than you would have to finance unregulated generation. The differences in financing are probably going to distort the comparison between the two. So where does merchant transmission stand in this? There are precedents in Argentina and Australia that say this can work.

Response: If we are going to be creative about inducing transmission investment, it is worth exploring. There are companies that would be interested in exploring those types of investment opportunities.

Comment: In terms of talking about regional bodies for transmission siting, that began to be tried 20 years ago for radioactive waste disposal, and it didn't work.

Response: What I view a regional body doing is addressing the need determination. But in terms of specific environmental siting, just like all politics are local, all siting is local. So I would still see that being done on a local basis. There will still be politics and public opposition. This is the use of a government power affecting people's private property rights. With transmission, you tend to not want it in your backyard, but it doesn't have the fear factor that radioactive waste does.

Comment: Two comments. One: Some of us advocate a model where the default supply ought to be the wholesale spot market price for all customers who don't choose. I was concerned that this might result in too much price volatility, especially for small customers. But we ran an estimate going back 12 months of what residential bills would have looked like if they had been on spot market prices as default supply, and the highest month-to-month price swing we saw was 20 percent. Volume differences of commodity purchases are small--only $10 or 20 a month. So now I think that it is the bigger customers who are going to care a lot more about volatility. Two: There is a problem of institutional credibility. There is no way to make the rules about congestion management and managing the grid transparent enough so that everybody can look at an event and say, yes, you did the right thing. It's too complicated. So you have to have institutions that people believe in so that in a crisis, people have enough faith in that institution that they did the right thing.

Question: What role is appropriate for RTOs in the transmission planning business? Should they simply provide information to the market, so that those who seek to invest in either generation transmission do it at their own risk, even though we recognize that one is regulated and one is not? Do we presume that the RTO should induce or require cost-effective investments?

Response: The RTO rule is set up for the RTO to not only plan for, but to direct construction. So, it is explicit as to the direction of the RTO. It is important that we strive for transmission to be a viable alternative to new generation.

Comment: We have a flow problem, TLR and price spikes, and we have to deal with these things quickly. I wonder if we can't as an industry put inter-regional coordination on the fast track, coordinating flow-based modeling, perhaps on an interconnect-wide basis, while we figure out RTOs, ISOs, transcos and the rest.

Question: If you pass along the spot price, you will be paying too much for this commodity. If you set it below that, you're going to create an adequacy problem. So what is behind this?

Response: The response was that we will just do this for people who want to sign up for it. But as we move away from the traditional obligation to serve, that volatility is going to affect everybody, even the single mom that didn't sign up for the real time program. The question is whether there is going to be a backlash against that socially, politically, given that this is an essential product. We're telling people, this is great, you're going to save money. We ought to at least be intellectually honest and communicate that in the long run it will be better, but it's not going to be all gravy all the way along.

Question: I'm curious about different demand responses. What about bringing on some of the existing back-up generation capacity that people have for other reasons? What are people looking at in terms of back-up capacity, how feasible it is to use it?

First Response: All of the entities in California—the ISO, PUC, Energy Commission--are working on a plan, and that is one of the things being looked at. There are bound to be good market solutions, but they haven't got the response yet.

Second Response: I have seen numbers in the area of 10 GW in terms of backup generation that hasn't been tapped. But the environmental issues are huge. There was an office building in downtown Houston with a 5 megawatt generator. Given that the market isn't open in Texas, their gaining access to the distribution system was a real issue. Beyond that are the significant air quality concerns of the city.

Question: Bonneville Power Administration is 80 percent of transmission in the Northwest area. If it becomes an RTO or joins an RTO, does its eminent domain authority transfer with it? If so, what are the implications for whether or not this RTO ought to be a transco with profit or non-profit?

First Response: I would guess that their eminent domain authority would go with them as they are currently situated. The one thing you don't hear anyone discussing when talking about diversification of fuels is that almost 50 percent of the generating capacity for hydro is up for relicensing within the next 5 years. That is going to play a huge role in this.

Second Response: Under passive ownership, if they had financial ownership only, they could certainly have that relationship. If they pass the audit with no control issues, it can be a factor.

Third Response: The delegation of authority wouldn't automatically transmute into something they elected to join. It's a tight delegation. They would have to ask Congress for a change.

Comment: We can recognize that there is a love-hate relationship with the volatility of electricity pricing. But the love side of it is that we did get a couple thousand megawatts of investment that came in to keep the lights on because people perceive that if they could get potentially $5-6,000 a megawatt hour even for a short number of hours, that could make the difference between returns that are acceptable and returns that are not. Maybe a five percent difference in the total amount of money over the year can mean 100 percent difference in the return on equity. That's the leveraging that we have to recognize in a market. So, we're not necessarily talking about massive differences for the consumer, but big differences in terms of whether people are going to invest there or invest somewhere else. We have to find a way to truly make it a market and not something else.

Session Three: Regional Transmission Organizations: The Rulemaking and the Rules

The multitude of comments on the RTO NOPR provide so many options that the FERC could find support for almost any view. The final RTO rulemaking is not the last step in the process, but it is important. Interpretations of the lines, and between the lines, must confront the practical realities of implementation. In part, those areas of the country that have implemented major reforms will have to assess their conformity with the new rules. Those who have been unable to act, or simply waiting, will now reassess their plans for implementing market reforms. The same issues are there, including access, pricing, investment, congestion management, regional coordination, and moving through the transition. The long debates over theory and practice will not go away, but the rulemaking serves as the foundation for the next plateau in what has become an increasingly sophisticated examination of a surprisingly complex set of policy problems.

Speaker One

Order 2000 certainly leaves all the options open, and I advocate one particular option: the combination of a Gridco with an ISO. The inherent weakness of an ISO alone is the reliance on fragmented transmission owners to design, permit, finance and build new transmissions. The inherent weakness of a transmission company performing all of the functions is the issue of ownership, which leads to questions of governance and independent market oversight.

I would support a regional transmission company in New England that has the following characteristics: It is for-profit, it makes money, it pays taxes, it's investor-owned, not owned or controlled by generators, distributors, energy system providers or vertically integrated utilities, not owned or controlled by the participants. The board of directors is elected by and accountable to the shareholders, and the officers are elected by the board and accountable to the board. Price is regulated by FERC, hopefully some way other than rate-based. Most important, the company works with, not in place of, the regional ISO.

I have come to this conclusion by examining the functions that need to be performed. Form should follow function. There are nine functions:

- Assure open access to the regional transmission system.
- Operate the electric power markets.
- Monitor the electric power markets.
- Execute the electric power markets.
- Maintain reliability.
- Serve as the clearing agent.
- Plan the transmission system.
- Operate and maintain the transmission system.
- Build new transmission facilities.

The first six should be performed by a truly independent body that is an ISO. The next two would be performed jointly, with a contract spelling out who does what in the planning, operation and maintenance of the transmission system. The building of new transmission would be the responsibility of the Gridco.

Several principles are important. Transmission is still a monopoly. Regional problems require regional solutions. Building transmission takes time. It's expensive, difficult, and independent market oversight is essential. Transmission operations and planning have to be closely coordinated, and the power exchange and the system operator should be in the same organization and building.

With those principles in mind, I would like to respond to some of the criticisms I have heard of the concept of ISOs with Gridcos. One criticism is that ISOs can't build needed transmission lines. I think that's a valid criticism. That's the reason we need a Gridco in addition to the ISO. Another criticism is that by having an ISO and a Gridco, operation of the transmission system is separated from ownership, and that's bad. I make three points. First, NEPOOL operated the transmission system of New England, which was owned by somebody else for the last 20-plus years. Second, many hotels are owned by one person and operated by somebody else, and it seems to work very well. Most importantly, there are basically no operations to the transmission system.

Another criticism is that ISOs lack the incentive to maximize throughput. But generation equals load, so there is no way to change the throughput between generation and load. Next is the criticism that self-perpetuating ISO boards are accountable to no one. Boards are accountable to customers, who are the participants in the market. They are also accountable to the end-users of electricity in terms of providing them with a fair market price. The final criticism is that the four existing ISOs are too small. New England and New York are around 20 gigawatts. PJM is the biggest in this country, along with EDF in France. There is, though, a need to improve coordination between the centrally dispatched areas. We need to strengthen the ties, remove some of the bottlenecks, make seamless borders so transactions across boundaries are easier and there is a free flow of information.

I choose to call our two choices deregulation and competition. In deregulation, there is open access to the transmission system, but also protection of native loads. The utility would continue to be the system operator dispatching its system, probably at marginal costs. There are bilaterals between utilities and their neighbors and between independent generators and their customers. Retail competition is now becoming state law, which confuses the issue. In this approach, utilities are following the functional separation of generation required by FERC. There is no ISO. The utility continues to dispatch the system, and instead there is a regional security coordinator that looks at reliability over multiple control areas. Finally, distribution would be functionally separated, as well as energy service companies. This raises a question: When the functionally separated generation company sells power to the functionally separated distribution company or energy service company, is that a sale for resale, subject to FERC regulation, or is it for a state to control because it's still one company?

The other option, underway right now in New York, New England, PJM and California, is the spot market. There is also a bilateral market at the wholesale level. Market and dispatch are by the ISO, except in California, and retail choice is being phased in over a fairly short period of time. The utility strategy, under this approach, is to sell or spin off most or all of its generation, to transfer its assets to a Gridco or have within the Transco a separate, independent ISO to perform the market oversight. Distribution would still be regulated.

I believe the competition model will work and will produce long-term benefits to society. There are many challenges to existing ISOs, and I am not holding them up as perfect. There are governance problems, market design problems, problems with integration and new generation. But I believe all those problems can and will be solved. I don't believe the deregulation model will work because of market power.

Speaker Two

I want to focus on the basic structure of RTOs. What is important is how you coordinate the actual use of the system.

Order 2000 is motivated by dealing with all of those problems of transmission systems, particularly loop flow problems and the difficulty of defining property rights. We recognize that we are going to have some kind of organization, preferably a regional organization, to deal with the second-by-second balancing of the system with respect to transmission constraints. The Order puts out a series of functions and characteristics. A thread runs through them: Looking very much for market-oriented solutions, things that are going to work with the competition model that the previous speaker talked about.

The only thing that was new in the Order is the eighth function--coordination across regions. That is a very important element of the system. There are many implications of the physical characteristics of the grid that drive us toward the need for a system operator. One of the characteristics of that system is that, if you have an efficient outcome, no matter which of the models you talk about, you end up with different prices at different locations in the system whenever the system is constrained.

We really don't have a choice between centralized and decentralized coordination of the market. There is no model that doesn't have centralized coordination. The system operator has to perform certain functions, given the technology. The question is how the system operator will do it, and I always reduce it to three questions: Is it going to be allowed to offer an economic dispatch service? Should the system operator use marginal cost pricing for power provided through the dispatch? And should everybody be allowed to participate as much or as little as they want? Should it be voluntary participation? I am convinced, both from theoretical reasons and practical experience, that if you answer "no" to any one of these questions, you are in trouble. So, just say yes.

Order 2000 says yes. The core idea flows from the responsibility to have a market-based solution to the problems and the key functions that flow from the balancing market that the RTO has to provide and make available to everyone. Order 2000 says a great deal. The centerpiece is that bid-based security-constrained economic dispatch with normal prices flows from the requirement to have a balancing market. The requirements of the order have all of the components of a bid-based security-constrained economic dispatch.

At the top is the bilateral schedules game. They do it in Norway. They do it at PJM. They do it everywhere. There is no dichotomy between the bilateral and the coordinated spot market. They can live together side by side as long as you have this centerpiece and you charge for the bilateral transactions. It's a difference in locational prices. In Norway, I believe, about 85 percent of the market is contracted for in this bilateral way, with only 15 percent being handled through the coordinated spot market.

Along with this come financial transmission rights. How do you define what the rights are that people have for using the system? How can they hedge against the changes in the prices? What can you give people in exchange for investment in the system? When you are upgrading the system, I would argue that a necessary requirement is that if somebody invests in the transmission system, they should get something for every investment. If they don't get something that is related to actually using the transmission system, it's going to be very hard to motivate them to invest in the transmission system. There is a natural way to define transmission rights, and it is those that you see in PJM and New York, and that will be coming in New England.

License plate access charges are consistent with that. We can have different charges for access at different locations in the system.

We are not going to solve all problems of investment. There may not be a sufficient way to deal with the free rider problems. However, there are lots of things in transmission and certainly in generation where we could let the market decide. But an essential requirement for doing that is that they have the pricing incentive to do so.

The RTO Order is right on target,

along with the earlier Capacity Reservation Tariff. The big question is whether FERC is going to follow through. If so, then we are going to have a big success. If industry participants and everybody else involved follows through and comes forward with sensible proposals, and FERC endorses them, or if FERC says no to proposals that are going to create problems, then we are going to be all right. The recent decision in California was very important, in that the Commission said, Let's go back and look at first principles about how we design the markets and try to make it more consistent with the framework that is in the RTO rule.

The other part of the RTO rule that is new is a big section on lessons learned. If you read through that, you will learn a lot.

The other part of the conversation is the Transco, Gridco, etc., etc. story. My view is if you have the ISO-Gridco model and organize the ISO consistent with the framework, everything is going to work just fine. If you have the Transco model, you're going to have a little ISO inside it so you start to figure out all the rules, and you have to have the same kind of procedures. But what you can't do is avoid the fundamental problem of making sure you have that basic framework.

There is a schedule and a set of things that the Order says we are going to do. I don't think the message is lost--if this doesn't work and work pretty fast, something else is going to happen.

Speaker Three

Implementation of the FERC order is going to be challenging. In the Midwest, it has been virtually impossible to reach consensus on organizing and managing the regional transmission grid. The Midwest has three dozen control areas, three reliability council regions, all of which operate under different rules, and there are about 70 TLRs a month just in the MAIN region.

There are three major approaches to grid regionalization, represented by three proposals in various stages of being debated. One is a pure Transco, the Alliance. The second is a traditional ISO concept that is not fully defined in practice and that will not become operational for at least another two years. The third is a transmission company operating under the oversight of an ISO.

The Midwest divided the role of the ISO and the for-profit transmission company that would operate under its jurisdiction, and asked what are the functions that are purely business operational functions versus what are oversight functions. The conclusion was that an ISO needs to be the security cop for the entire region, no matter how many variations in the Transco you build under that ISO. There also needs to be a reliability cop. You cannot run a system with three reliability council regions who don't talk to one another and who issue unenforceable different rules. You need a market monitor. In the Midwest, you can operate a market in close coordination with the operator of the grid, but it does not have to be identical to the ISO. The ISO should be the market monitor. There should be conflict resolution other than going to FERC every time two people disagree.

The rest is business. If you have a CEO who wants to organize his vertically integrated utility into business functions, he is ready to divest, especially in a state that has divided retail competition into three different business functions regulated in three different ways. His Disco is regulated by the state and open access. His Transco is regulated by FERC and the different rules on the Disco, and his generation is in the open market. He decides to try to sell this transmission asset and invest the money.

But if he is trying to build a Transco in the region, how does he go about doing it and also meet all of the requirements of his regulators? He asks his interconnection partner if he wants to build a grid with him. That partner responds, I wish I could, but my state regulators are preventing me from doing it for other reasons. How about if we get into a leasing arrangement? He goes to the next interconnection, and meets a public power district. The public power district cannot divest because of its own rules and cannot enter into leasing because its bylaws don't permit it. Can he participate in the building of the Transco? Yes, under an operating agreement that it's long-term, that's it open, that it's negotiated and that's how you go about building that grid that operates under the ISO. Is this a good thing to do? When will that grid become of sufficiently large scale to be thought of seriously by everyone concerned? Can we proceed this way?

These questions have been asked of regulators. They apply especially in the Midwest, where the ISO has postponed to an indefinite future some very fundamental structural problems. The Midwest ISO has no market design associated with it. It has no serious congestion management. It does not know how, when it does become operational, it is going to be able to run a grid that has three dozen control areas. No one has been running a grid with three dozen control areas through a central dispatch system.

There are many views on this. The issue is whether the progression that has taken place so far will be allowed to mature and to work. Is it possible to organize a viable market in this very fragmented region, where will it start, and is it possible to provide the incentives that are needed for the very costly process of consolidating control areas and reliability councils?

Speaker Four

I will try to touch on the parts of Order 2000 that are the most interesting both to me and to market development at this time.

The goals of restructuring include reliability. How is grid reliability going to change in the market regime, and what are the implications for how to think about RTO design?

Another goal is to promote efficiency. You can think of the lower curve being effectively feasible. What is feasible? It is what suppliers could do at minimum cost, stretching as hard as they could to supply all they could at the lowest price possible. You can think of demand feasible as maximum willingness to pay for this product. But you don't go into an automobile dealership and say, I'm willing to pay $25,000 for the car, when in fact it's selling for $20,000. So there is a difference, because of your own self-interest or the self-interest of the generators, between what you announce and what your true willingness to supply or demand is. So we get an outcome Q actual, whereas we could get Q feasible. If we have a good market design, we will get as close as possible to Q feasible, and that is efficiency.

We have difficulty obtaining this goal because of the lack of an incentive to reveal the true willingness to supply to the market. So what we need to do in the market design is make it desirable to profit-maximizing suppliers to submit this maximum feasible supply function, just as utility-maximizing demanders wish to submit the maximum feasible. In other words, through their actions in the market, we get both sides to reveal their true willingness to pay.

We don't know what the best solution to this problem is. But with the flexibility of the RTO design, we will learn over time what the characteristics of the optimal design are. However, a caveat is that we need to get standardized data as well as performance monitoring across ISOs so that we can learn what works and what doesn't.

The dimensions of flexibility include the ISO/PX split. Because of coordination of the grid, you always need this residual market, but it is really for things like hedging for forward contracting. Another is the non-profit versus for-profit distinction. There is a huge debate in the literature, and this hasn't been resolved. Another dimension is regulatory mechanisms—cost-based regulation and performance-based regulation, and their problems. On congestion management mechanisms, there are many approaches we could take, and several are listed in the FERC Order. There are spatial aggregations, spot prices, and temporal aggregation in prices as well. Over what interval do I pay for the congestion that I cause?

How does grid reliability change in the market regime? We could think of grid reliability in the old regime as the percentage of time that I get power as a customer. In a market regime, it is the percentage of time I can get power at any price. However, there may be times when, given that price, I don't want to consume. Thus, one of the ways to get benefits from the competitive process is to take seriously this aspect of grid reliability, and think differently about generation reserves and other aspects of reliable grid operations.

On the issue of performance-based regulation, I want to caution that, as implemented, it often just amounts to an inferior form of cost-of-service regulation. Examples come from the U.K.'s National Grid, as well as U.S. telecomm, where there is a percent change in CPI minus a so-called X factor. The theory is that I set your price independent of your actions, and because the utility has to satisfy all demand at that regulated price, total revenue is fixed. However, the regulator finds it difficult to maintain a given X factor when it begins to affect the firm's profit abilities. So PBR becomes cost-of-service regulation with an option to obtain very high profits if the X factor is set too low.

So, we may not want to dismiss cost-of-service too quickly. The Order notes growing scarcity of transmission capacity. Cost-of-service has the problem of strong incentives to over-invest. But in this case, that may not be a bad thing, as it may enhance market efficiency. It may enhance the number of feasible trades.

I would advocate public data release, data sharing of confidential data among market monitoring units of RTOs. A lot of information could be gleaned, as well as measures of market performance that can be compared across markets over time and within the market at the same time.

This is information from the California market, where this index is the ratio of the difference between the actual market price and the competitive price times the difference between the total ISO load and the must-take load in the ISO. Therefore, that is the total cost increase due to non-competitive pricing, divided by total cost, which gives you a measure of the deviations of market performance. In the off-peak months of the market, things were working very well, so that these sorts of efficiency problems only tend to show up in the high-demand peak periods. It is individually rational to maximize profits, and that's what we should allow. The nice thing is that we have enough data to compare these indices across markets, look at what aspects work better in what markets.

Why do I think this is the missing ingredient in the whole RTO Order? What makes competitive markets work is the demand side of the market. It is the potential for high prices that allows consumers to express their willingness to pay. That is where all the benefits of restructuring will come from. We need more sophisticated final demand. This has benefits to all market participants, reducing market power and price volatility. High prices make it profitable to be price-responsive. There is room for this in policy as a carrot-and-stick approach.

In conclusion, competitive markets should be able to get by with a lower level of capacity and serve the same demand functions. A necessary condition for this to occur is a sufficient number of price-responsive customers. If you look at the U.S. airline industry, in the last year before deregulation, the highest load factor was 55 percent. Now load factors are closer to 72 percent. We have lower average prices, and the regime works because we have lots of very sophisticated, price-responsive customers. Once these things happen in electricity, I think we will see tremendous benefits.

Discussion

Comment: I would like to get on the table the idea of ISOs as not-for-profit entities. There are three reasons why I am concerned. First, I'm not sure there is any real accountability of the kind that corporations have. Second is the messy, ugly stakeholder processes. The third is that I like the idea of their having an incentive to figure out new ways to do things.

Response: I agree on the issue of accountability. In the real world, boards of corporations have to be ready to fire the CEO. I have some concerns about a self-perpetuating board. In terms of the governance issue, it is not working, and it has to be changed and will be changed.

Comment: A board of an ISO cannot be taken to court to collect economic damages. That makes ISOs fundamentally different from a for-profit company.

Response: I disagree. I would maintain that the governance of the New York Stock Exchange, the Chicago Options Exchange, and numerous other financial exchanges are the same. They are now not-for-profits, and there is talk of converting them, but that's after they have been in operation for 40 or 50 years. But I agree that the ISO has to have some financial assets, or its liability is meaningless.

Question: One of the keys to making the market work is demand elasticity. We have at least two places with price caps. In California, the load aggregators, when they had caps, didn't have the incentive to sign up customers beyond the traditional, interruptible load programs. How do you get rid of this issue to get the benefits?

Response: Were it not for the stranded asset recovery mechanism in California, there would be no rationale to have a price cap. The difficulty is that under the current regime, the only entity that has any incentive to keep wholesale prices lower are the incumbent IOUs, because they get greater CTC recovery from that. So the ESPs make no money off of providing interruptible service, because the extent to which they keep prices lower is the amount they have to make up in higher CTC payments. If not for that, you say that the cap is coming off. But besides that, there is very little rationale to continue to have it for exactly the reason that you state—it is much cheaper for me to argue about the big, bad generators than go out and install the technology necessary for that to happen.

Question: What do you do about market power during the transition period without crushing market signals and deterring entry? How do you strike a balance?

Response: Once you give all market participants access, the opportunity to see the same set of price signals and the freedom to respond to them, then you could say that the market will decide how much market power is tolerable. If you think of it as in the airline industry, some market power exists because there is a large enough fraction of customers who are not price-responsive. But given the structure of the industry, there may be impediments to the ability of all participants to see the same set of signals. That is like the equilibrium level of market power in the industry. The next step is to consider structural remedies—anti-trust or divestitures. But if we solve the first step, we will be surprised at how well things work.

Comment: I would that argue in California, it is primarily the regulatory barriers, the CTC, that are standing in the way of a lot of progress. There is a lack of faith in retail competition.

Comment: One of the fundamental premises about restructuring is not that we're going to get short-run balance of supply and demand better than we used to. The reason we restructured was for dynamic efficiency. The touchstone I would always come back to is to make sure you're getting the incentives right, getting the prices right, getting the signals right consistent with that dynamic efficiency argument. That means you're going to do a lot of things, even in the face of market power. For example, zonal aggregation and averaging makes market power worse in the short run and destroys the dynamic incentive for new entrants to come in to dissipate the market power. So you want to go to price signals, even in the short run, that are sometimes very high. Retail caps should be set very high. Then you just have to live with it to a certain extent. I also think you get a different answer depending on whether you're talking about the old assets that came up under the regulated environment versus the new assets. You want a sort of hold-harmless view that anybody who comes in prospectively and starts building is not constrained and can charge anything they want, as opposed to creating new RMR contracts, so that you have a transition for the existing assets. For those RMR contracts, you should be charging something like the scarcity price when they're running at full capacity in order to get a proxy for demand. You have to keep focused on that dynamics: What is the incentive for people to enter? What is the incentive to make investments? What is the incentive to change their behavior? An absolutely necessary condition is to get those prices right. If you suppress the information, we are never going to get out of this box.

Question: If the RTO provisions of the Barton bill are enacted unchanged, does that call into question FERC’s authority to do Order 2000, or change how FERC would go about implementing it?

Response: It calls into question FERC’s authority to police the market for undue discrimination. It doesn't affect Order 2000 to the extent that you view it as a voluntary regime that sets out the bounds of an optimal RTO. Since it would enact FERC's functions statutorily, they would arguably become the maximum requirements that the Commission could require of RTO formation. It would prevent FERC from ordering the creation of an RTO or from ordering a utility that would be a logical component of a regional market to join an RTO.

Comment: In terms of market power, an interesting issue that wasn't addressed is that we look at these things in terms of market performance. I wonder if we could look at the bidding strategies of individual plants and players. You wouldn't expect the marginal costs of a plant to change a lot over time. So it might be of interest to look at the time profile of bids for a particular unit.

Response: A lot of papers have looked at exactly those issues in the U.K., California and other markets, analyzing who is bidding and how. I wanted to focus on an index. The difficulty with that is that it uses confidential data, so that will get at the market aggregate. But I certainly think understanding bidding behavior is a first step.

Question: Should there be a requirement that each retail customer have the option to take real-time pricing, whether locational or not?

First Response: That would be my preference. But you could say that as long as all customers above a certain size were offered it, you wouldn't have to offer it to the very small ones because the administrative costs would be too high. I would not require all customers to have it, but I would offer it to them.

Second Response: We know that the electricity markets will be the most volatile markets in the energy sector, probably of any commodity. It is difficult for me to believe that the majority of consumers would be able to manage that volatility. So there has to be a broker in the middle to interpret and assume part of the responsibility for managing that volatility. I believe that only a limited number of customers need to play, although I believe absolutely that they should be at play.

Question: Does a Gridco or for-profit transmission company accommodate merchant transmission investment in addition or in parallel to that, or is there only a single entity that can make such an investment?

Response: These two can exist side by side. Any time you have some competitive actors and some regulated actors in a market, that will create problems. But I don't think those are insurmountable difficulties.

Question: Everyone is cautious about trying to do real-time pricing on the residential front because of the social realities. But air-conditioning cycling programs have been implemented by utilities around the country for 15 years. Why isn't everyone encouraging, if not requiring, the T&D

utilities to put into effect good air-conditioning cycling programs?

Response: The Department of Energy is interested in this. I would point out, though, that what you're often really doing is synchronizing so that my air conditioner is on for the first 15 minutes, yours for the second 15 minutes, etc. It is not clear that you're depressing the total system load that much.

Comment: But in, for example, Commonwealth Edison's "Nature First" program, there is a flat payment to the residential customer who allows shut-off for two hours or eight hours.

Response: Initially, the utilities bore the cost for these demand-side programs. With competition, the new suppliers want the benefit of having demand-side, but they don't want to bear any of the cost. So it is a struggle to figure out, when a customer who is already on a demand-side program picks a new supplier, who will bear the cost of implementing these programs.

Comment: I think these programs are worth pursuing. And as you go from 20,000 to a million people participating, the costs will go down.

Response: Giving someone real-time metering technology helps to create an intelligent consumer—one who may change suppliers if he sees that he is paying too much.

Question: What role should state commissions play in RTO formation? Should they sit back and let people bring them things? Or give people some direction?

Response: One of the important roles that state regulators can play is to work with their jurisdictional utilities and the leadership of those companies to participate actively in the FERC collaborative process coming up this spring. In the long run, I see some differences in the roles of state commissions in those regions that are considering ISOs and a more participatory or democratic governance process versus those regions that will rely more exclusively on a transco model. It seems that the opportunities for active participation by state policymakers are somewhat diminished in the latter case. Their opinions are influential in the Congressional debate. Although their stances on RTOs, state/federal jurisdictional issues, etc. reflect a lack of unanimity, that makes those opinions just as critical. Also, how this issue plays out at the wholesale level is going to be influential in the development of retail markets, where state commissions play a critical role.

Comment: We need to have a vision of what this market is going to look like. We have to keep testing actions against vision. One touchstone I would come back is, I am a great believer in markets, but I don't think there is much of a market for market design. That is something that is fundamentally a social problem, and has to be addressed by government or government-like entities that are trying to address the broader public interest. We're not trying to simply balance the interests of the market participants. Sometimes this means standing up and saying we're going to require, for example, doing things that allow prices to go through to customers, even though it's politically unpopular. The job of regulators is to make sure that customers see a fair market price.

Question: The U.K. is proposing to abandon uniform pricing and go to discriminatory pricing. What will that do to the marketplace there, and what should we be watching for here in that development?

Response: I know of no serious person who has looked at the proposals for reform in the U.K. who thinks they are a step forward. They will enhance market power. I think it will collapse under its own weight. They have never been able to answer the hard questions about how this is actually going to work, and how they're going to deal with it. Muddling through is not an acceptable way to deal with it.