Nineteenth Plenary Session
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RAPPORTEUR'S SUMMARY*

Session 1: Making Regional Transmission Organizations Support Competitive Electricity Markets

There may be no set of issues more fundamental for electricity restructuring than the institutions (ISOs, gridcos, transcos,…), rules (scheduling and curtailment, native load priority, CRT,…) and pricing policies (license plate, nodal pricing,…) for access to and use of the transmission system. Stranded cost recovery will come to an end, divestitures and mergers will reshape the players, and states will resolve the retail access principles. But for public policy in the foreseeable future, the essential requirement to make the market work is for customers and their suppliers to have access to the essential facility, the wires. Evidence that the topic is so important is found in the extended debate about the plausible, better, or best approaches. If this were easy, it would have been done a long time ago. If designing the details were not so important, there would not be such intense disagreement, in region after region, over arcane matters that were long hidden in the vertically integrated utilities. But there is a growing sense that time is running out and the stakes are getting higher. There is a demand for action, whether legislative or regulatory, but we fear the result because there is not yet a clear picture of what will work well. There are many pieces to the puzzle, and the pieces have to fit together. To move ahead, there is a need to sharpen the debate, crystallize the issues, and then choose a model or models for regional transmission organizations that have a reasonable chance of success in supporting competitive electricity markets.

First Speaker

I will make a distinction between the system operator, which makes market balancing and operating decisions, and the gridco, which builds and maintains the wires, giving people access by hooking them up. Those are distinct roles in the RTO (regional transmission organization) NOPR (notice of proposed rulemaking), which lays out a design with four "minimum characteristics" and seven "functions".

The minimum characteristics are: independence, regional scope and configuration, operating authority for all facilities, and exclusive authority to maintain short-term reliability. The NOPR goes into a fairly detailed description of each one. The same is true for the seven functions, which I won't list here. What is important is that the NOPR doesn't just list seven things at a level of abstraction that could mean anything—it discusses each one, specifying enough detail to make a real difference. There's some ambiguity, but also a great deal of guidance, which is a good thing.

RTOs fit into a general framework in which there has to be a system operator providing a dispatch or balancing function. Should the system operator be allowed to offer economic dispatch to find the least-cost combination? Should it apply marginal cost principles for

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efficient pricing? Should everyone be allowed to have access to dispatch and to participate in the market? How you organize the business isn't so important, but the answers to these questions really do matter. The way I read it, the NOPR answers yes to all of them, resulting in a consistent framework for putting the system together in a way that will actually work.

The basic idea is that you have to provide balancing functions, you should have efficient pricing—because prices matter a lot if you want to give people flexibility and choice—and, finally, everybody ought to have access. Financial transmission rights can be structured within the system. They're called various things in different parts of the country, but the idea is to have a financial mechanism integrated with the market that allows people to pay in advance for transmission price certainty, giving them the equivalent of firm transmission rights. That's completely compatible with license-plate access charges, and captures the important idea of a multi-part tariff — you pay one thing to get access to the system, another to use it. There's no reason why the access charges should be the same across the entire U.S. or across the state of Massachusetts. They can be different in different places.

On balance, I see the RTO design as very much on target, and quite consistent with the Capacity Reservation Tariff (CRT) NOPR. If you put the two together, the whole thing works well, with two big ifs. The first is if FERC means what it says. Its record is pretty good, for example, many in the industry objected quite strongly to the CRT proposal, but it is in fact being implemented in PJM, and soon will be in New York and New England. The second is if FERC follows through, which again is a question, because a decision has not been made to make things mandatory.

Let me finally mention an institutional design issue. The transco is a regional organization that combines both the gridco function and the system operating function, so the same entity owns and operates. But it seems that if you have the same entity owning the wires and operating the system, you have to define the market participants relatively narrowly or take the view that the transco is the only entity allowed to make transmission investments. This seems to be fundamentally inconsistent with increased reliance on market forces.

Second Speaker

It's very important to understand that the transmission system has the properties of a natural monopoly and a public good. For the last decade and a half, FERC has been preaching that it is important to unbundle the network and the commodity services, which is essentially what it has done in the RTO NOPR.

Self-governance groups are a new process to get people like NERC, RTOs, and ISOs together and decide issues early on. Instead of debating whether we should have for-profit or not-for-profit boards, you establish a settlement procedure before the formal FERC process. I'm not saying balanced governance groups are the answer to everything, but they do look a lot like a FERC settlement conference. The idea is to take the process, create good voting rules, and see if problems can be solved before they come to FERC.

It's also important to understand that RTOs don't own any generation, so the only way the system stays in balance is through markets. The question is how you design those markets. There's no generation sitting around under cost-of-service regulation for the RTO to call on, so it needs to contract with generators, and we need to work out how to facilitate that on long-term and short-term bases.

Why are we doing all of this? The real payoff is in generation, which comprises over 70 percent of costs. If you can lower that, the 10 percent attributed to transmission is small in comparison. What's happening to stranded costs? There's good news when you look at divestiture of old cost-of-service regulated units. Non-nuclear assets are fetching about 200 percent of book value and, albeit with a small sample, nuclear assets are getting 10-20 percent of book value. If you take these two numbers and extrapolate them to the entire generation set, you find there are no stranded costs. That's a simple extrapolation, and I don't want to oversell it, but it's a useful observation to make.

There's also been a resurgence of the debate on incentive regulation. If you read the law, you won't find the idea of profit, because fair prices don't necessarily stem from profits. Consequently, the Commission has been looking at the idea of incentive regulation for some time, working hard to decouple profits from prices.

To get the ISO-RTO market structures right, we need to start thinking seriously about balancing markets. Let me go over a few red herrings in this debate. In my opinion, an independent, for-profit transco is an ISO, so the argument about having one or the other doesn't make a lot of sense. The key is to get the incentives right, rather than worrying about corporate status. The only real difference between for-profits and non-profits is how they file their tax returns.

Should we have financial or physical rights? The difference between them is that, when they define physical rights, most people mean the right to physically withhold capacity. If you take that away, things become much more complicated. In both gas and electricity, we don't allow participants with physical rights to withhold them from the market. If you don't schedule them, they go back to the market and get rescheduled.

Another important thing that has evolved over the last several years, and California has contributed a lot to this in a very positive way, is market monitoring. These markets are young and have lots of problems, so the idea is to constantly observe how the participants are behaving, and make continual improvements.

To conclude, if we get the RTOs' incentives, institutions, and contracts right, there will be all kinds of benefits. Stranded costs, in my opinion, will melt away, leaving faster trading, lower transaction costs, lower prices, higher quality service, higher profits, and less regulation.

Third Speaker

I'm going to be talking about a transco, or independent transmission company (ITC), structure for the RTO. When I use the term transco or ITC, I mean a stand-alone public company that owns, operates, and maintains transmission assets, but also has the system operator function and may lease some transmission assets under long-term contracts. This is distinct from the ISO model or the gridco model, which separate transmission ownership from the system operator function. I'm talking about for-profit entities, not owned by or affiliated with integrated companies or any other market participants, that perform the system operator function in addition to owning and managing transmission.

Let me make the affirmative case as to the advantages of these type of entities as RTOs. I want to state at the outset that simplicity, in my view, is not a special benefit of these institutions. In particular, having a for-profit entity is not a silver bullet that obviates the need to address the difficult issues to which previous speakers have referred. These old chestnuts will still be with us in an ITC or a transco world: Physical versus financial definition of transmission rights, how to manage and price congestion on the grid, integration or separation of energy and ancillary services markets, and so on.

With respect to transmission expansion, you will hear from some august bodies, including the Federal Trade Commission, that transcos or ITCs are inherently bad with respect to transmission expansion because they favor transmission at the expense of generation or other options. I'm sure it's possible to poorly structure a transco or an ITC so that this is the case, just as it's possible to poorly structure an ISO or a gridco, but I don't think this is a fair criticism. We ought to let markets determine when it makes sense to expand the transmission system. For example, locational prices on either side of a constraint are a pretty good way to send price signals, and they are no more of a problem in a transco or ITC than in any other structure.

There are also people saying that there's underinvestment in transmission, but that transcos will remedy this, getting investment up to the required level. Again, I don't think that's a benefit to ascribe to the transco. The problem of what to do when markets don't bring forth the right amount of transmission investment because of economies of scale or scope is a hard problem that every system has to deal with. If you're going to have a system in which a taxing authority can build and roll in transmission, you have to do that very carefully in any model.

What are things that might be counted in the benefit category? The first is a new, better definition of independence. If you separate transmission ownership and control from everything else, you've achieved more independence than in an ISO model. The question is whether that would that spill over into governance.

The second benefit is avoiding the separation between system operation and transmission maintenance and operation, in which one set of people are maintaining the wires and running the switches, while somebody else is trying to run the system from a reliability perspective. There have to be contractual relationships establishing who's doing what and how it works, some of which can perhaps be simplified if we put everything together.

The third benefit is that we have additional opportunities for incentive regulation in structures where the system operator and the assets are in the same place. It's not clear where we're going to go in terms of incentive regulation in general and for the system operator function in particular, but every regulatory system, including the current one, has some incentives in it. There will be different incentives in an ISO structure, and they may or may not be the ones that we like. For instance, in the current setup, there are people who have the system operator function and also serve retail load, which leads to a trade-off between reliability and economics at the margin. There's no way to avoid that, but I think there are more options in a transco or ITC world, in which there's an asset base along with the system-operator base.

An additional benefit, which may be the most significant of all, arises from the fact that the NOPR articulates two important, but potentially conflicting, themes. The first is volunteerism rather than compulsion in establishing RTOs. The second is raising the bar in a number of areas, particularly independence, which may make the current ISO form of the RTO less attractive. What the NOPR says about the independence of the RTO makes continued ownership of transmission an extremely passive investment opportunity. From the asset owner's perspective, when you have an RTO in place as described in the NOPR, you no longer get a lot of the rights previously associated with your investment. As it is we have a spotty history in assembling ISOs under what people thought was the very definition of independence, so what should we expect volunteerism to produce? There are few other kinds of investments that have similar passivity characteristics, and from a fiduciary perspective they raise difficult questions for utility managers.

How can the ITC or transco structure help? Well, sale or spin-off of transmission assets may be preferable to passive investment for transmission owners, particularly if the ITC has some reasonable incentives in its own right. I have to add that there are disadvantages too, e.g. tax and transaction costs that can be fairly burdensome, particularly if the limited liability corporation (LLC) structure allowing income taxes to be minimized is judged to fail the independence test.

So, the NOPR provides an interesting dilemma if we're going forward on a voluntary basis. If my diagnosis is right, it will not increase the attractiveness of the ISO route from the perspective of skeptical transmission owners. If the LLC is ruled out, that's going to make transco spin-offs very difficult from a tax perspective, so we're left with an ITC that has some transmission assets and leases a bunch more.

Fourth Speaker

The title of this panel is making RTOs support competitive markets. The goals are reliability, efficiency, and equity. Nobody contests that, but they're easy to state and a lot tougher to make work. Overlaying markets on an integrated network is complex, and efficiency is difficult to measure. How do you know you have an efficient market? What do you compare it to? What measures are there? Also, equity is always in the eye of the beholder. Your view of equity and my view of equity are not necessarily the same, as the stranded cost debates clearly demonstrated. Yet there's been great progress since Orders 888 and 889, and we now have an opportunity to use the lessons learned over the past few years to respond to the challenge put forth by the FERC in their RTO NOPR.

Some lessons can be learned from looking at two ISOs, California and New England. One is to get the incentives right. When they're wrong, strange things happen and people have to make administrative rules when problems occur. Second, if you follow the money, the financial interests of the parties will tell you why they're taking particular positions.

What is the formula for success? There are three primary ingredients. One is to put people with significant knowledge about reliable power system operation and market incentives together at the start. Most incumbents have ample experience in reliability, but less in markets, so there's a tendency to grab simple solutions that later turn out to be quite problematic. In California, the market monitoring committee was extraordinarily valuable in helping sort through problems, because they were able to look objectively at what makes sense for the public interest.

The second lesson is to create a structure that meets the FERC NOPR objectives. In terms of the problems that were encountered in trying to get things right in New England and California, the principles in the NOPR will work. The difficulty is how to create structures that incorporate those principles. Will people go far enough by themselves? It was pretty clear in regard to governance in the Northeast that the incumbents were never going to let go of their power without FERC stepping in.

Finally, it is critical to establish a governance structure that can correct design flaws and market power problems. The California model, where people deal in terms of making changes in the public interest, has worked far better than the Eastern model. People thought a stakeholder board would never work. But highly knowledgeable people were found who debated the issues, because each of them had a fiduciary responsibility to the public interest— they were a public-benefit corporation, not a voluntary association—and no party was able to dominate. The investor-owned utilities had three seats on a board of 26 people, but many of the things they fostered happened, because they were knowledge leaders who proposed things that made sense. Similarly, if consumers or generators had a proposal that was in the public interest, they were able to get majority support for them.

In the Northeast, things move slowly because of a governance system that gave too much power to a few. It now has moved toward a two-tier structure, with an ISO board that is knowledgeable and independent of the market participants, but isn't engaged at the detailed level, and a voluntary association without fiduciary responsibility who, in fact, really work out the rules. It's difficult to see how that type of governance structure will keep up with the pace of change that's going to be necessary.

With regard to issues of structure, FERC has left open a range of options for voluntary filings, but I believe that the ISO-gridco model is the best way to achieve FERC's goals. When it comes to issues like for-profits versus not-for-profits and transcos versus ISOs, I don't agree with some of the comments that the previous speaker made. I really believe that in a transco you'll have a bias for transmission, so there has to be a ring fence around the ISO portion of the transco, and then you're back with all the same problems of functional unbundling chronicled in the FERC order. You end up with a model where there's the suspicion, if not the reality, that proper and objective decisions are not being made in the ISO portion of the transco. If we can't get more ISOs and if the ring-fence problems can be dealt with, then I think it's better to have transcos than to do nothing, but, if we can get the ISO-gridco model to work, it has a better incentive structure and is better able to meet the public interest.
Incentives are what it's all about. With regard to for-profit transcos, the simplistic statement is that for-profit companies are more motivated, more customer-oriented, less bureaucratic, and so forth. I don't think that really holds water; the question is whether there's an alignment between the profit motive and the public interest. If there is, great, but I doubt that alignment is there at a detailed level. In California, a large portion of executive compensation was linked to public interest goals established by the board, which is probably a better way to motivate people.

Where do we need to go with regard to ISOs? They need to have a stronger role in driving the consultative process, e.g. via their FERC filings. I question whether the financial interests of voluntary associations will lead to the same conclusions as a process with the ISO more in control. I would also require RTO board meetings to be open, except for discussions about personnel, contract, and litigation issues. If you really want to build trust in these organizations, people have to be able to access their deliberations and see how they're deciding rules for the future. It's not in the FERC NOPR, but I believe that openness leads to better decisions and more confidence in the process.

Discussion

Comment: We felt things in California would never work if both vertical and horizontal market power weren't mitigated. Horizontal was cut into with the 50 percent divestiture of generation, but the vertical was equally important because a lot of people had strong views about the incumbents' inability to deal with grid problems. The perception was that the grid needed to be as independent as possible. Divestiture seemed like the right answer, but the utilities' view was that it would take five years to get the bondholders' approval, which meant that setting up a transco would have taken too long. If a transco had been chosen, the state wouldn't have had to split the power exchange (PX) and the ISO— that wasn't an efficiency decision, but was because people didn't trust the incumbents.

Comment: I agree that a participatory board looks and feels a lot like a settlement conference. And, just like a settlement conference, to get consensus requires compromise and flexibility, so you get decisions that no one really likes but everybody finds acceptable — the only rationale is that they're what everybody would agree to.

Response: It's obviously not perfect, and, in the course of putting together this NOPR, there were endless debates about boards with independent members versus boards with market participants. I think there's a place for both of them. In governing the ISO and providing the right incentives to manage the system, maybe an independent board is the right way to go. A stakeholder board may not have enough interest in keeping costs to a minimum to govern properly. But when you don't have a stakeholder board, you end up coming to FERC much more often, as in the gas market, where the transco simply puts together a filing and the first time anybody sees it is when it comes to FERC. There are places where one type of arrangement is better, and places where the other is. I don't think either solves all the problems by itself.

Response: A stronger question is: If you try lots of different things, does the most efficient system naturally develop from the market place? Also, when you get groups like this together, do they do a pretty good job of solving common problems, where there are a lot of externalities? There's extensive debate about this in the economics profession, and a lot of empirical work showing that efficient institutions and the best rules don't develop naturally, because things are highly path-dependent. Second, there is some research looking at fisheries and so forth and—unlike the economic models that say these problems are never solved because you get overwhelmed by the externalities— there's evidence that, on occasion, they are solved. But to say that whatever comes out of this process is, by definition, the right answer would be a fundamental abdication of the regulators' responsibilities.

Question: What did Congress intend when it passed the Energy Policy Act? I thought it meant wholesale competition had become the law of the land, so we could move on to figuring out retail issues. Maybe some of the disagreement about what ought to be done can be explained in terms of different perceptions of the ultimate goal.

Response: The purposes are probably clearer now than they were then. The Bush Administration simply proposed making it easier for entrants to come into the marketplace and generate power. The House took the position that just being able to enter the market is not enough, you also have to be able to access the grid. It was trying to create more competition in the wholesale market, because a lot of congressmen had lost faith in the regulatory process as the most effective way to get incentive structures that maximize efficiency. Politically, the House simply went as far as was acceptable to the small circle of people who had to make the decisions. The assumption was that more efficiency would be gained, but the notion of customer attentiveness was not so important, because the retail side wasn't being dealt with.

Response: If the states had continued to regulate companies as before, with vertical integration the norm, the Energy Policy Act would have had a very modest effect—it would have facilitated trades between vertically integrated utilities, and municipal utilities would have been able to shop for power. I don't think the dramatic changes we've seen would have taken place without the alterations in state regulation, industry restructuring, and retail access. The NOPR puts it well — Order 888 was the foundation for the things that have gone on, giving states the opportunity to take other initiatives. It was the narrow vision that people had in mind that made the Act politically possible. Probably the industry would never have what happened happen if they had realized there was going to be so much transformation. It also lent legitimacy to FERC's push for open access in various proceedings, sending a signal that it had Congressional approval.

Question: You talked about equity being in the eye of the beholder and the difficulty of measuring efficiency and defining the public interest, but then said that your employment contract had clear objectives and incentives. How do you get from having such difficulty coming up with definitions to getting clear objectives in your contract? Who set them and who decided whether you'd met them?

Response: There was a compensation committee with representation from multiple constituencies, and there were many months of meetings to discuss what was trying to be accomplished. Ultimately that led to semi-quantitative objectives on which people could be judged. For example, you can make projections as to what might reasonably be expected for the relative value of different products and their volatility. To the extent that you can then measure what's actually happening in the marketplace, that tells you something about whether or not you have rules that are leading to efficient markets. It's a big mistake to think lower prices are the only goal, because, as we saw with cost caps during the oil embargo, when you try to depress market prices, all you do is build up tensions that make things worse later on.

Question: A number of speakers addressed the question of incentives in the RTO development process. At this stage, it's clear that there are tremendous incentives for vertically integrated utilities to hang on to transmission for the benefit of their own generation. How do you suggest putting incentives in place to form either transcos or ISOs?

Response: In debating the NOPR, incentives were a prominent issue, but not one on which the Commission's thinking had advanced very far. There are acquisition premiums, risk-adjusted rates of return, and, ultimately, performance-based rates that FERC has invited the industry to help it develop, but which haven't yet happened. When it comes to setting up appropriate rules for access and pricing and other issues, it is still unclear which incentives translate into good public interest rules.

Comment: I haven't heard much about how to introduce real competition on the grid. There's talk about market-based incentives for investment in transmission, but in other industries, such as telecomm and natural gas, facilities-based competition allows market forces to keep everyone in check.

Response: How far can you go with market-driven processes for transmission investment? It's possible to construct examples showing market failure, but nonetheless I think you can do a great deal. It worries me that the debate in this country assumes a monopoly investor is needed, as opposed to looking at where there might be boundaries. In Argentina, the process for investing in transmission is complicated, but is driven by market forces, as was the construction of the Direct Link project in Australia. Market-driven investment is an important area that's quite compatible with the RTO NOPR. The structure is all there—it's part of the theory in PJM, New York, and New England, although no one's actually building things as yet.

Comment: When I look at the things that have been addressed to date— fairness, equity, efficiency, and reliability—it seems that the physics got left out, even though it has implications that are germane to the objectives we're pursuing. Size does matter, as do shape, internalization of loop flows, constraints, and so on. In the U.S., we currently have over 3,300 electric utilities and over 100 control areas, which just doesn't fit with the things we're trying to promote. When you look at what has happened to transmission in this nation, it has undergone a radical change with Order 888 and open access. The new objectives—fair, efficient markets, and so on—are the right ones, and in fact were the things that caused tight pools like PJM to form in the first place. But, going forward, there will need to be a fundamentally different proposition to create competition and investment in transmission. Electricity is different from other commodities in that only supply currently responds to price signals. Because of that imperfection, we need a lot of rules and mechanisms that are band-aids for the lack of demand-side response. It seems to me that the future will bring things like distributed generation and micro-turbine fuel cells, as well as demand-side response, that are going to compete with transmission.

Comment: In California, the ISO is going to be responsible for two categories of transmission planning. One is reliability transmission planning, in which, if the ISO identifies a reliability problem, there will be an annual auction where transmission will compete to be the solution with distributed generators, big generators, or even demand-side management. If you are selected to provide the reliability service, you will be required to enter into a contract with the ISO to guarantee that you'll be there as a generator, or as a load shedder, or whatever, when needed. The second category is non-reliability related transmission that might be needed, for example because of load growth. Load forecasts will be done on a 5-year planning cycle, and reasons why the existing transmission system might be unable to accommodate the load—such as voltage problems or thermal problems —will be identified. Then an auction will be conducted, and all the players can compete. If the transmission operator wins, she'll be given the opportunity to build a transmission line. If she doesn't want to build—e.g. because the returns aren't high enough —then somebody else will provide a solution. The goal is to stay ahead of the game in terms of load growth and reliability needs.

Session 2: The 1992 Energy Policy Act, Plus Seven Years: What Have We Learned? Where Are We Going? Where Should We Be Going?

Congress could scarcely have envisioned the changes that have taken place in the seven years since the passage of the Energy Policy Act of 1992. Indeed, no one could have foreseen all the changes or the pace at which they occurred. Restructuring of the electricity industry and the electricity market has changed the very way we think of the electricity system. The opening of retail markets to competition, formation of regional transmission organizations, disaggregation of vertically integrated companies, unbundling of services, and the appearance of marketers and other actors in the marketplace were scarcely on the horizon in 1992. The rich experience, here and abroad, provides us with much that we can use to reconsider the best road ahead for public policy. What do our reflections over the past seven years reveal? What have we done correctly? What mistakes have we made? What can we learn for the future? Where are we going? Where should we be going and how do we get there?

First Speaker

The message of my talk is that the competitive revolution has had real benefits almost everywhere it's been tried, but it's not easy to get it right. The key to success is fairly simple: a conscious effort to closely integrate the central market with the dispatch process, so system pricing internalizes network externalities. It's very hard to internalize the complex, real-time externalities that arise in electricity networks; if you don't have some way to internalize them, somebody, namely the integrated utility, has to be in charge of managing them.

There are only a few options for managing a scarce resource. One is to ignore the fact that it's scarce and let it be used inefficiently. Another is to have a monopoly own and manage it. And a third is to create property rights and markets to price the scarcity. If the reality is very complex and you have a problem that's too serious to ignore, you have to create either a complex market or a monopoly—those are the only choices. It doesn't help to say, "We don't want some monopoly controlling this, we want a market, but we want the market to be simple." If the reality is complex, either the market will be complex or a monopolist has to do more than you would like.

If you look at economic history, the development of competitive markets is largely the story of some common resource, such as land, becoming more scarce and run-down, followed by a conflict over how to define and allocate property rights. Often a monopoly is created, or the resource is given to the government to own and manage. Over time, more sophisticated property rights and trading arrangements develop. In simple cases, they evolve naturally, but in more complex cases someone has to sit down and decide what property rights make sense; markets won't design and operate themselves.

Take the case of air pollution. As you get more people doing things in the economy, you start having pollution problems, and the first thing that happens is the government makes up some arbitrary rules as to how they should be managed. Eventually tradable pollution rights are created to get market processes in there, but the problem is so complex that there always has to be somebody defining and administering the property rights.

There has been a natural monopoly in electricity for a long time, not due to the economies of scale in generation, but because of an inability to define property rights that can be traded and allocated efficiently. The breakthrough in creating competition has been the development, facilitated by modern information technology, of spot markets administered by some sort of independent system operator.

Debates in different countries about setting up markets produce many of the same issues. Every country says, "Our system's different. Our problems are different. The things you did elsewhere aren't going to work here." They are always a little different, but I'm struck by how much they're all the same. The attitudes of the people are the same, the options are the same, and, in particular, the kinds of arguments that get made tend to be the same.

One debate that constantly dominates is over physical versus financial rights— should markets be based on decentralized trading of physical rights to use scarce capacity or should there be centralized pricing of physical effects with financial rights and hedges around it? This should be a pragmatic question; ideally you'd like a decentralized market, but to decide whether or not it will actually work, you have to ask whether it's possible to define physical rights that will use the system rationally, reasonably reflect actual physical constraints, and be traded efficiently in external markets.

In a market based on physical rights to output or capacity, the idea is that you can't consume output or use capacity until you have a right in your hands. This works fine if the rights can be traded, and so get allocated efficiently. In a market based on centralized pricing and financial rights, some people have the right to the output or capacity, but instead of trading among themselves, everyone comes to the market, whether they own any rights or not, and bids to use the physical stuff that's there. A central market process finds prices and quantities consistent with the bids that people make and the actual physical reality on the day to determine who actually uses the stuff. Then there's a process that says if you used it but didn't own it, you have to pay, and if you owned it but didn't use, you get paid.

In electricity markets, you need centralized pricing and financial rights because there are two fundamental externalities. One is what I call the theft externality—there's no practical way to prevent somebody who's connected to the grid from taking power, whether they have a right to it or not. Therefore you can't really enforce physical rights, and so need a separate pricing process that determines who actually takes power, with payments being made after the fact. Second, you have loop-flow externalities, associated with flows on the grid, which are very complex.

The separation of physical and financial contracts is largely a distinction without a difference. For most things a physical contract means that I own something, and if anything happens to it I'm responsible; if its value changes over time, I gain or lose accordingly. But nobody possesses electricity on the grid —it goes in and comes out instantaneously—so any kind of deal with a physical contract can be done just as well under a financial contract if you have a well-developed market.

There are such things as physical contracts, which aren't about delivery of the commodity, but have to do with some other action, for example saying you have to produce your electricity in some particular way. But generally, when people talk about physical and financial contracts, what they really mean is the real-time trading and operating process, a commodity contract that requires the buyer and the seller to exchange some quantity during a particular hour. If they don't, somebody defaulted and a payment has to be made related to the resulting damages.

If you have an efficient ISO spot market in which everybody's buying and selling power, then if I don't deliver the power I was supposed to, you can just buy it in the market instead. That mitigates the damages and defines them at the price in the spot market, which makes it very easy to write clear financial contracts. If there's no such ISO market, then you're forced to trade short-term physical contracts instead. So, the argument about physical versus financial contracts is not about the form of the contracts, it's about the form of the short-term trading mechanism.

Under centralized trading with physical rights, people determine what they want to do and take their contracts to the system operator, who knows what can actually be done given the grid realities, such as transmission capacity. The system operator might go to the short-term market and tell the participants that they can't do what they wanted. The producers and consumers don't have much individual incentive to solve the problem the system operator identified, but they trade again and come up with some revised contract quantities and give them back to the system operator, who identifies new conflicts. This process is repeated until they run out of time, when the system operator has to use some kind of non-market process to close the gap between the final contract quantities and what the grid can actually support. It costs her money to do that, because she can't just order people to do things that close this gap, so she's got to pay them. Then she's got to spread these costs among the producers and consumers.

In a market with centralized pricing and financial rights, what the system operator does is very different. The producers and consumers send their contract positions to the ISO, along with information about the amount by which they're prepared to change their operations in response to prices. The ISO runs an hourly market, figuring out in one round prices and quantities that are consistent with what everybody wanted to do and with physical reality. She charges everybody for what they took when they didn't contract to buy, and pays them for what they sold when they didn't contract to sell. So she still does the settlement, but there's only a small gap to fix, because the market solution better reflects grid realities. Thus, when you go to this kind of central market, you eliminate a lot of the middleman activity and greatly reduce the amount of money that has to be used to close the gap between the market solution and the actual solution.

So, the fundamental problem in an electricity system is that, because the network externalities are so large, decentralized trading leaves a big gap between the market solution and reality, which the monopoly ISO has to somehow clean up. The more you try to keep the market simple when reality is complex, the bigger that gap is going to be, which is not, in the end, very efficient. The main problems are the management of congestion, assuring enough peaking capacity, and difficulties with retail competition.

The problem with inefficient congestion management is that the complexity of loop flows means you can't define tradable physical rights that use the system efficiently. The solution is to have centralized locational prices, which take into account all the loop-flow effects in one fell swoop, and then use some kind of financial transmission rights to see that those who have the rights get paid, even if they don't physically use them. You can't do this without a market that is closely coordinated with system operations.

The problem in assuring enough capacity is the theft externality—if you're connected to the grid, you can take power out whether or not you have a contract. The only thing that enforces a contract is the penalty applied by the system. The notion that the market is somehow going to solve this problem is nonsense—there has to be an agreed-on definition of the penalty. Even with hourly pricing, it's not going to capture all the effects, because most of the things that really threaten the system happen in minutes or seconds, so will get averaged out. The ISO can always keep the lights on by contracting with somebody for reliability reserves, so problems don't necessarily affect reliability, but they certainly affect costs, as important decisions get moved out of the market and back to the system operator.

Another problem is that there's very limited retail competition around the world, for several reasons. One is that people are concerned about stranded costs and the like. Another is that there are very high transaction costs for small consumers, although one way to keep those costs as low as possible is to use the same solution that seems to work at the wholesale level—that is, ensure that small consumers get the spot price and that anybody can compete for their business.

The way you make incremental improvements is to say that the monopoly distribution company's job is not just to deliver electricity to final consumers, but to deliver it to them at as close to the wholesale spot price as can be estimated by profiling, or interval metering, or whatever. The distribution company charges me the spot price—so I'm effectively in the wholesale market —and my bank automatically pays them every month, so I never even have to see the bill. Now the distribution company might offer me 1,000kWh a month at 3¢/kWh. If I agree, then I'd pay the bank $30 a month. At the end of the month, without knowing anything about what I actually did, the bank figures out how much it would have cost me to get 1,000kWh using the profile the company has for me. If it's more than $30, they charge me the difference; if it's less, they credit me for it. So, I'm effectively selling back on the spot market, and because somebody else can come along and offer me 2.9¢/kWh as an average price, there's a form of retail competition. It's not as good as having spot meters and all that, but it allows for effective competition.

So, the basic message is that competition works wherever it is based on an ISO spot market. There've been real benefits in reducing monopoly control and cost insensitivity, stimulating investment even in systems where there wasn't any investment in the past, and reducing costs. Competition has been less successful when it is based on physical contracts and decentralized trading. And that's no coincidence.

Second Speaker

I'd like to comment on where we've been and where we're going in three areas: wholesale markets and transmission, retail competition and customer choice, and, finally, the environment. Let me start by reiterating that the Energy Policy Act of 1992 and the subsequent FERC regulations, Orders 888 and 889, are not in themselves the reason why electricity rates went down. Those federal actions are properly viewed as necessary, but not sufficient, conditions for stimulating the rather dramatic changes that we've seen in many parts of the U.S. over the last several years. State initiatives have played a very important role, in particular with rate plans, which make utilities the residual claimants on gains they achieve by buying power at lower prices, generation divestiture, which creates distribution entities and generating facilities that want to sell in the market, and customer choice, which produces additional demand in the wholesale market.

Looking back, it's amazing that FERC has been able to create a framework at the federal level that is flexible enough to deal with these dramatic changes without taking a very strong view as to which direction things should go in. They deserve congratulations, because it's surprising that we haven't had more problems in harmonizing diverse state actions with federal programs that govern transmission and wholesale markets.

At the wholesale market level, especially in states that have done a substantial amount of restructuring, one lesson a lot of people have learned is that it isn't so easy to create efficient, competitive, wholesale markets in a regime with decentralized buyers, decentralized generators, and independent network institutions, rather than control areas governed by vertically integrated utilities.

The challenges turn on some of the special attributes of electricity—non-storability, the need to continuously balance rapidly changing supply and demand, network reliability considerations, and network externalities. The failure to recognize these special attributes in institutional design is a prescription for serious problems, and the California experience over the last 14 months demonstrates both the successes of creating competitive markets in this type of decentralized regime and some of the problems.

The day-ahead market that the PX operates has worked well—it's very competitive in most hours. But because there's really no demand elasticity in these markets, when demand is very high a perfectly inelastic demand curve is trying to cross a perfectly inelastic supply curve, so there are problems. More importantly, even in markets with a relatively large number of suppliers, there are potentially significant gaming opportunities. Markets without storage and without an active demand side can run away in certain hours, producing an infinite price, or whatever the largest number is that the computer will take.

So, one of the things I've learned is that we need to work harder to get demand elasticity into these markets, and one of the most important things that retailers can do is to sell consumers price-sensitive, interruptible services. Not only would they be doing their customers a good turn by keeping them from paying hundreds of thousands of dollars a megawatt hour, but they would also be helping the market work. Until we get demand elasticity, there's got to be some type of default price in these systems to stop prices from running away. I know there's lots of rhetoric that real competitive markets don't have price caps, but in fact lots of commodity markets have special administrative procedures that come into effect when there are market dislocations.

More problems have emerged in the California ISO, which took over all the activities that went on inside the mysterious black box we called the vertically integrated control area operator. The market surveillance committee has identified problems with the ISO's markets for ancillary services, the so-called reliability-must-run contracts, and a variety of others. It has also suggested solutions to these problems, e.g. the tariff has been amended many times and is still a work in progress. In part, a number of the ISO's problems have evolved from separating the PX and the ISO, which was a mistake. Also, the air-traffic control model—that the ISO should manage the electrons but shouldn't get involved in the economics—just isn't possible. The ISO has to be involved in the economics of operating the network, and if it's going to be a buyer of ancillary services, it has to buy these services rationally. These are the kinds of things that the ISO is trying to fix at present, and I'm sure as time goes on that the problems will be mitigated.

It's very hard to get well-functioning markets in an environment with committees representing 25 different interest groups, which was part of the process in designing the California market. In the end there are right answers and wrong answers, and one of the tasks for the regulators is to make decisions when parties can't come to a reasonable consensus, if for no other reason than to protect consumers. Also, the market-surveillance committees— there are two in California, one for the PX and one for the ISO—

have played a very constructive role, bringing independent expertise to evaluate the market and placing pressure on the ISO and the PX to fix problems. I hope that some form of surveillance program is continued in other areas of the country, because it can be very important for making these markets work well.

Incentives for efficient investments in transmission capacity is a major issue that has not been grappled with adequately. Rate of return regulation for investment in transmission assets is not going to fly going forward. Also important is matching the expanse of transmission network organizations and institutions with the geographic expanse of electricity markets. Fifty control areas in the Midwest is too many; they exist for historical reasons going back to the 1930s, having to do with the expansion of vertically integrated utilities and the refusal of state and federal regulators to allow mergers. Over time there has to be a consolidation of control areas, and I hope the NOPR will lead to good thinking about that.

Let me turn to retail markets and retail competition. In many markets, retailers deliver additional services to consumers. They provide convenient locations, a broad inventory of goods, after-purchase installation and service, return privileges, and so on. Providing value-added services is the reason retailers exist and can charge customers a retail margin.

In electricity, the choice between wholesale and retail is especially challenging because it's very easy to buy at wholesale if the system is set up in a way that allows it—the electrons come to my house over the same network regardless of who sells them to me. All I need is someone to read my meter and bill me at the wholesale market price. For consumers, the ability to buy at wholesale is an important protection from false and misleading advertising, because if I look at my bill, I can compare the prices that are being offered to me with what I could buy at wholesale.

What value-added services can retailers provide? They could, for example, install an interval meter in my house to help me reduce the electricity used during high-priced hours; they could provide energy management services, long-term contracts, and so on. If they're going to be successful in the long run, retailers should have to provide these types of services, although I wouldn't be surprised to find some retailers trying to make it difficult to buy wholesale so that they can thrive without providing them.

Let me close with a couple of comments regarding the environment. At least in New England, environmentalists who supported restructuring had at least three things they wanted to get out of it. First, they wanted to stimulate the deployment of more efficient fossil generators, combined cycle, and renewable energy sources, allowing them to enter the market without having to go through a convoluted bidding process. Second, they wanted to facilitate the retirement of uneconomical coal and nuclear plants by confronting them with the realities of market economics. And, finally, they wanted to stimulate the provision of energy management services to encourage more efficient energy use.

Although markets have only been operating in California and New England for a little over a year, from the environmental perspective, there have been many positive developments. There's a long line of mostly gas-fired generators trying to enter the market, retail green-power initiatives have been quite successful in a number of places, and some retailers—especially those selling to large customers—are providing energy management services and joint marketing of electricity, gas, and telecommunications. There have also been continued, and quite transparent, subsidies for energy efficiency and renewables that no one has complained about—they seem to be a socially accepted tax.

It would be unfortunate, however, if public policy moved towards further efforts to promote environmental goals by distorting the operation of competitive markets. For example, some of the proposals that are contained in the Clinton administration's Comprehensive Electricity Restructuring program are distortionary. In particular, portfolio standards are an unnecessary and anti-democratic intrusion into competitive markets, hiding the cost of environmental improvements from the public. They're not the best way to go about encouraging renewable energy in a competitive market system.

Third Speaker

Sometimes I try to foresee how future historians will evaluate our restructuring efforts. Here are a few tentative conclusions. First, they will be astonished at how easily today's legislators and regulators have accepted claims that the regulatory compact requires utilities to have an opportunity to recover all their stranded investments, and they will be especially wide-eyed at the ways that this opportunity has been expanded to provide the utilities with a far greater degree of assurance of full recovery than they ever enjoyed under traditional regulation.

The next thing that will puzzle historians is our failure to apply with equal vigor the corollary, which those favoring full strandable cost recovery readily concede, at least in theory—namely the proposition that if the customers are at risk for all the assets whose market value is below book value, then they're entitled to all the gains on utility assets whose market value has risen above book value. In states where customers are paying off stranded costs, it would seem unthinkable for utilities to keep such gains. But think again. A few states—Illinois comes to mind—do not require that the gain on power plants sold for more than book value be paid to customers to mitigate stranded costs.

Other variations on this theme are more elaborate. What happens when, stranded cost recovery having been established and power plants sold, the remaining utilities are acquired or merged, with stockholders receiving a price well above book value? How can shareholders who have been shielded from restructuring losses now be entitled to keep the part of the gain that's attributable to the elevated market value of regulated assets?

My favorite version of this outcome is occurring in Boston, where the local electric utility decided to use its backbone fiber optic network for telecommunications. There's nothing wrong with that; indeed, it furthers the pro-competitive objective of the Telecommunications Act of 1996, and a number of utilities are leasing excess capacity on their fiber networks to telecommunications firms on a wholesale basis. In New York and New Jersey, the profit is used to mitigate stranded costs, at least until those stranded costs are gone. In Boston, however, the utility has transferred the right to this network, at book value, to a joint venture in which its holding company has a half-interest under exclusive, anti-competitive provisions. Unmindful that the value of this network comes largely from the facilities paid for by electricity customers, the utility is seeking to capture the above-book value for its owners in the form of profit or capital gain in the joint venture. The bottom line is that they are offering customers only the book value for their backbone fiber network while asking them to make up the diminished value of, for example, their nuclear unit. Clearly, customers would have been better off to have acquired all of the assets during restructuring than they are in agreeing only to pay for the losing portion of them.

I should also note an irony that's developing as restructuring moves from states with high strandable costs to states where the exposure is small or non-existent: We're seeing utilities reject the idea of a regulatory compact, as Potomac Edison (whose net market value is above its book value) recently did in Maryland. "Of course," they say, "our investors were always at risk if market values fell. We might have built a nuclear plant and been stuck with those below-book values. Therefore we're entitled to keep all the gains since we were at risk for losses that we didn't actually incur."

When restructuring was first discussed, utilities were the main opponents, followed closely by environmentalists. Within five years the nation has achieved a near total buy-in, with utilities now demanding to be restructured, as though that was the goal in itself. Many major environmental groups have joined in this push, on condition that efficiency and renewable-energy expenditures be secured by law or regulation. At this point it is helpful to note the concept of revealed preference—that is, our priorities are revealed less by what we say than by what we actually do. It's certainly true that restructuring was supposed to be about customer choice, but here we are, five or so years into the process and what have we actually done? We've made full recovery of strandable investment more secure than it ever was under traditional regulation by, for example, eliminating the requirement that these stranded assets remain used and useful. But have we securitized the customer side of the restructuring bargain with equal determination? Not yet.

For a century, our regulatory commissions have viewed themselves as surrogates for competition, and now with little warning they're expected to midwife the real thing. The two roles are very different, especially because the tools of conventional antitrust, which aim to preserve competition where it already exists, are not very useful in opening markets that are monopolized or that involve access to an essential facility owned by a potential competitor. On top of these problems, the urge to merge, characteristic of all monopoly industries as barriers to entry go down, presents its usual blend of attractive efficiency gains on one hand, and unfortunate loss of competitive potential on the other. Some of the efficiency gains can be shared in the form of freezes and reductions, though the pricing flexibility gained under the freezes may itself be put to anti-competitive use.

The structural steps that would have rapidly promoted competition have not been ordered, although voluntary divestiture has been occurring at a rate faster than anyone would have guessed four or five years ago. The ISO structures that have substituted for a complete severance of transmission ownership from generation seem to be a problematic interim step that will ultimately have to give way to a clean break, although not without some years of litigation and waste. Indeed FERC's recent NOPR seems to be a partial confession that the bargain implicit in Order 888 was somewhat deficient.

Before wrapping up this retrospective, let me digress for a moment to a subject whose interplay with restructuring will intrigue our future historians, namely campaign finance. We have half a dozen examples of commission appointments around the country directly influenced by a desire not to offend major donors. When our historians seek explanations for some otherwise inexplicable digressions from the public interest this is likely to be a fruitful, but relatively impenetrable, area for research.

I have provided a dour assessment of the first five years of electric restructuring, but some perspective can be gained by applying the same exercise to the development of wholesale competition, which became a serious factor with the passage of the Public Utilities Regulatory Policies Act (PURPA) of 1978. Mired in litigation in its early years, reluctantly enforced by many states thereafter, and encumbered by the same avoided-cost forecasts that were then supporting the construction of the last dozen or so nuclear plants, PURPA's impact on the structure, and especially the technology, of electric power generation in the country and throughout the world has nevertheless been profound. The wholesale competition triggered by PURPA and enhanced by the Energy Policy Act has not only driven down the cost of new generation, it has reduced costs at existing power plants to the point at which at least two private buyers for nuclear generation have emerged. As with other introductions of customer choice, this one has already begun to push control away from central facilities and toward the customer, a trend that can only be furthered by retail choice.

Of course our historians are also going to want an international perspective, and I will venture two observations. One is that the issue of market power is crucial everywhere. The British, who seemed so far ahead at one time, have repeatedly had to circle back to struggle with the inadequate initial structure of their power supply marketplace. Second, the efforts of international lenders to force our concepts of regulation and privatization onto government-owned systems where prices are well below costs, meters are few and far between, and most customers either don't pay or barter, are going to backfire in ways more serious than anything that's likely to go wrong here in the United States. Reforms that might work over 10 years are being attempted in three to five years in economies that just can't handle them. The irony of our pushing others to do too fast much more than we, ourselves, are doing too slowly will be clearer to those looking back than it can possibly be to those of us who are living through it.

Fourth Speaker

In California, the changes gone through would never have been made without customer pressure. It was a systemic change that no administrator or regulator would ever have done on an academic or logical basis just because it was the right thing. The PUC was under intense pressure from large customers who were angry because their rates had increased by 50 percent, inflation was close to nine percent, interest rates were at 14 percent, and the state had lost over 500,000 jobs. There was close to a depression, and the commission got blamed for part of the problem.

The two big issues the PUC had to deal with were stranded assets and market power. It asked for voluntary generation divestiture, but was willing to give 100 percent of the principle in recovery at an 80 percent level of return. The PUC didn't realize that reducing the return by 20 percent was so onerous that it was enough to provide an incentive for the utilities to divest all their generation. So, if you get the incentives right, you get a good outcome, even if it's not strictly intentional.

Also, right in the middle of the 30-day joint committee session on writing the legislation, there was a 6-hour blackout that cost California $100 million, making the legislature very aware of the importance of reliability issues, some of which were heightened in the ISO legislation. If they thought they could have got a transco instead of an ISO in the timeframe they had, I think they would have proposed that, although I don't know whether it would have passed the hearings. It was the only way to solve the trust problem—if the owner of the transmission system was someone other than the person who generated the power, at least the IPPs and that group of stakeholders would have been satisfied. But that couldn't be done, they went with the ISO, and it has done very well.

Where are we going? California hasn't even begun deregulation from a customer standpoint. That will start in September of this year when, in the San Diego service area, price signals will get to all customers for the first time. (A rate freeze was put in place until all stranded assets were recovered in each utility, and San Diego's will be recovered by August). If you look at the market price of the California PX for the month of May, it was 1.7¢/kWh, compared to Massachusetts' 3.6¢/kWh. California's average energy price out of the PX for the year is 2.4¢/kWh—less in the months when there's rain for hydroelectric generation, and more in summer, when the average price got up to 4¢/kWh. In California, the average energy price is 5.5¢/kWh, so once the rate freeze is over, even if you do nothing, your highest rate will be 4¢/kWh, and the lowest could get down to 1.1¢/kWh. By the end of next year, when PG&E and Edison come in, California's price will drop 30 percent, which is $6 billion a year, equivalent to a 20 percent decrease in income taxes.

Two things the CA PUC should be proud of are that, at the Energy Commission, it has got 10,000MW of new generation for siting, which means $5-10 billion of new investment going into California. Second, if you read the newspapers, only 1.2 percent of the customers have elected to choose, but 19 percent of industrial customers with demand of over 500kW, representing 30 percent of industrial volume, have converted to choice and, by year-end, that figure will probably be 50 percent. As far as the residential customer, once the rate freeze is over, I think there'll be a lot of high-use customers who will react to price signals, resulting in demand elasticity.

Discussion

Comment: I agree that we need demand elasticity and real pricing on the retail side, and that marketers should do more to ensure that customers get them, but in some areas, particularly in New England, customers don't have demand elasticity because they see a set fixed price. Indeed, customers appear to prefer a fixed price, especially in the residential market. Also, in many states we're not permitted to have customers see real pricing in terms of metering or billing.

Response: I would be happy with a price that reflected the market price in the New England power pool. But you have to recognize that if there are monthly meters, you can't bill anybody more than the average price for the month, which means the meter provides a kind of hedge, wiping out intra-month price variations. It also doesn't distinguish between customers who are consuming mostly in the day and those who aren't. The monthly prices should at least vary with market conditions— I'm not sure the variation would be that large, but in principle it ought to be there. You should be able to put in a demand-recording meter, because the only way you're going to get price elasticity is by confronting people with hourly prices before the fact. Given current technology, that's likely to be most economical for large customers who have enough consumption to amortize those costs, but there could be technological changes that make it cheaper to sample retail consumption every ten minutes or every hour.

Response: When we first filed a restructuring proposal in 1995, our concept was that every customer would be on an interval meter, but then we realized how expensive that would be, particularly for residential customers, so we considered using load profiling, but allowing customers who wanted a meter to buy one. The problem is that smart marketers come in and pick off the high-load-factor customers who are being served above cost, leaving the default provider with customers who are being served below cost. So now we're in this position, especially for residential customers, where either everybody's in or everybody's out.

Question: I'd like to make a connection with this morning's discussion by asking the panelists about incentives versus compulsion from FERC. What is your view on where the balance ought to be?

Response: I had two reactions when I read the NOPR. First, that it's voluntary in the same sense that I volunteered to be in the army in 1969, three days before my draft board told me they were going to draft me. I think anyone who reads this should assume it's not really voluntary. The time-honored practice of regulatory extortion will probably provide the incentives to make it work, e.g. by withdrawing market-based pricing authority or taking a long time to approve various filings, including mergers. I would hope that most utilities will find it in their interest to participate in an RTO that has the attributes laid out in the NOPR, but I'm reasonably confident that those who don't will be forced into doing it.

Question: Five years ago, when we were all trying to figure out what to do about the enormous stranded cost problem, I would think about how easy it would be to be a low-cost state where the problem was stranded benefits. Now I'm wondering how FERC can, under current law, induce a low-cost state to restructure markets, even at the wholesale level. You can put in some sort of bilateral contract to try to capture the benefits, but, if your goal is to restructure markets, the great thing about stranded costs is that high prices motivate regulators to restructure, and stranded costs are a big stick—you say to utilities, "Here's the deal: if you want your stranded costs, divest generation." That's a big incentive. What kind of incentives could be put out there for low-cost states?

Response: I think this is a phony issue, because one way or another the low-cost power is going to find its way to the high-cost markets, and the ratepayers in the low-cost states are going to end up with the residual cost structure, so they're going to pay higher rates unless there's open competition allowing power to flow freely. Thus, the pressure to open up is going to be on both the high-cost and the low-cost states.

Response: I think it's perfectly sensible for a state like Idaho or Wyoming to say, "We're a small state with practically the lowest electric rates on earth, and we haven't had a lot of problems. We read all this stuff from California and PJM and New England and it's incomprehensible and there are problems, so let's wait and see what happens." As long as they abide by all the open access rules that FERC has issued, why is that a crazy thing to do?

Question: At the moment there's a tremendous incentive not to separate out transmission, not to join an ISO, and not to join an ITC or a transco. How do you provide incentives for people to do something with transmission other than hang on to it?

Response: Going back to FERC's initial efforts to get utilities to file open access tariffs, every time a utility applied for a merger, the answer, after all the hearings, was, "You need an open access transmission tariff." After a while people got the message. I suspect that that's what's going to happen here—in regions of the country where they haven't created ISOs, companies will find life a little more difficult with the federal regulators.

Response: One way to encourage volunteers would be to look at the kinds of transactions for which the owners of these assets seek approval, such as mergers. Since these transactions usually have a public interest standard somewhere in them, one could announce criteria defining the public interest, saying that mergers, for example, that contain these characteristics will go on a fast track, or will have a higher likelihood of approval. As long as you're dealing with a broad standard like furthering the public interest, there's quite a lot of leeway to define the guidelines. This has the further advantage that mergers will get structured in ways that include those actions, instead of trying to get concessions after the merging parties have negotiated the deal they want.

Session 3: Default Service: What Is It? Who Should Provide It? How Should It Be Provided?

Our previous discussions highlighted the importance of default service design as a critical and contentious issue. Regardless of what choices might be available to customers for energy service, not all customers will make an active choice. Certainly, if the experiences in telecommunications, natural gas, and electricity to date tell us much, many customers will not affirmatively select an alternative provider. In other cases, the chosen supplier may not perform. Who should serve customers who do not affirmatively choose a supplier? What criteria should guide public policy? Should customers be provided with some sort of incentive to affirmatively select a supplier and avoid default? Is the incumbent, or someone else, the supplier of last resort? Should default service be bid out in a competitive solicitation? If there is a solicitation, should it be for the entire set of defaulting customers, or should they be divided into subsets for the purposes of the solicitation? If there are to be subdivisions, what should they be? Would such a subdivision constitute, as some have complained, "governmental slamming"? Should a competitive solicitation of default service be designed to assure a diversity of winners? Or should costs be kept at a minimum? What pricing provisions should apply? Should low-income customers, whose rates may be subsidized through LIHEAP or through cross-subsidies embedded in tariffs, be treated differently for purposes of default service?

First Speaker

What are the underlying goals we're trying to accomplish? The four main ones mentioned in discussions of default service are:

- to offer something that would protect customers from undue price volatility during a transition period, rather than throwing them directly onto the spot market;
- to continue subsidies for universal service—and there are all kinds of cross-subsidies in existing service, especially in the residential class;
- to promote customer switching;
- to create an efficient market.

Different goals are going to drive us in different directions. For example, if we decide that protecting customers from volatility during the transition is important, we're going to hedge default services. But that reduces incentives for customers to switch, because one way new entrants can add value is by offering a hedging service; if one is in place already, that makes it harder for new entrants.

Thinking about default service, our most important goal ought to be to create an efficient, workable competitive market. By that I mean that the market should produce services customers want. The operative design features are that customers make the decisions about what they buy, other people aren't making those decisions for them, services are produced at minimum cost, and producers are betting with their own money, not using other people's money, e.g. to invest in nuclear plants.

It's important to keep in mind that default service has two functions. One is a physical supply function, and the other is a financial responsibility. There are two product designs that have been proposed. The first is making default service an unhedged service, i.e. a straight pass-through of the wholesale spot market. The advantages of this are that it gives efficient price signals and ensures that the level of hedging service is efficient, because if people go out and buy hedging, that's the ultimate test of whether they really value it.

The second design is to make default service a hedged service. I don't know of any state that doesn't have a hedged default service, at least for some transitional period. The concern is that, because the markets are not yet mature, there might be more volatility than in a steady state, so you don't want to just throw customers onto the spot market. The problems are that it's inefficient in the sense that somebody else decides what type of hedging service customers should have, and it makes it harder for new entrants to offer this value-added service.

In discussions, there is often some confusion over which customers should be eligible for default service. One view is that it should be a backstop for customers whose supplier fails to deliver or, for some reason, terminates them.

Another view is that it's simply for customers who don't affirmatively choose another supplier. Also, there are customers with special needs--people who use the term "provider of last resort" often think that role is about taking care of low-income customers in a competitive market. There is also a category of customers who are a high credit risk—they don't necessarily have low incomes, but for one reason or another they don't pay their bills. And then there's an all-encompassing definition that says any customer who wants default service ought to be able to have it.

A good place to start is to ask whether we need this service at all in a competitive market. After all, there's no default provider of home-heating oil; if you don't arrange delivery with a supplier and pay for it, you won't have heat. An important reason why we have to think about having a default provider is because electricity is a network industry, so the reality is that even if you don't pay your bill, the electrons still flow, so you get supplied until somebody physically cuts you off.

It's important to remember that the ISO is everybody's physical provider, so the default provider of the electrons is always the ISO. I've heard suggestions that the ISO itself should create a retail infrastructure to provide default service. The local distribution company has this obligation today, and in some states, New York in particular, it still has a legal obligation to provide it.

In an auction concept, there are two different ideas. One is that, through an auction of sorts, one or more energy service companies might win the right to be the default provider. The other is the reverse of that, where any company that wants to participate in the market might be assigned the obligation to serve a certain number of customers.

What will it cost? The answer is going to depend on whether or not the product is hedged. Starting with the hedged— and I'm assuming if it's hedged it has to be regulated—then we have to go through a process where utilities and regulators figure out what is the right amount of hedged supply, how much should it cost, who should decide the auction rules, who pays how much for what, and so on.

If it's unhedged, the default supply is a pass-through of the spot market, so the cost of the commodity is going to be the same regardless of who the provider is, whether it's the ISO, the local distribution company, or the energy service company. What will vary are the transaction costs associated with providing the service. The issue is that, at least at the moment, the local distribution company is the only player in the market who has scope economies in transaction costs between the commodity markets and delivery. These scope economies are there because delivery services are sold on a volumetric, customer-specific basis so, for the delivery company to make sure that it's paid properly, it has to have databases to calculate bills, even if they're aggregating customers and sending that bill to the energy service company. Any other provider in the market has to build duplicate capabilities to sell the commodities separately, so they're going to incur some sales and marketing costs.

Thus, at the moment, the local distribution company can provide default service at the lowest administrative costs. Why is that important? Well, for large customers it's not important because they're buying such large quantities of electricity that their bills will be hundreds of thousands of dollars a month, so something like 95 percent of the cost of serving them will be the commodity, and the transaction costs will be small relative to the size of the load. That's not the case for residential customers, who have bills of tens of dollars a month.

The average cost of customer acquisition is \$50-75 a year. The average residential commodity bill (for a typical customer in the north) is \$192 a year; the average retail margins on commodities are in the neighborhood of 3-7 percent, which would yield an annual average profit of around \$10. So to make this work, in this example, a supplier would need to keep a customer for 5-8 years just to recover acquisition costs. Of course, if electric customers switch every couple of years like telecommunications customers, suppliers will have to recover transaction costs over two years, adding 25-40 percent to the commodity bill.

Who should pay for default service? In most cases the customer taking the service would pay, but, e.g. for low-income customers, you could completely separate the question of who should pay from all the other design features, assuming that there's a tax mechanism in place to support ongoing cross-subsidies.

I would propose that default service should be the unhedged, wholesale spot market price, should be made available to all customers who want it, and should be provided at minimum administrative cost. If there's all this value to be created for small customers, why force them to have access to it at a higher cost than is necessary? Customers are the best judges of whether the benefits of choosing an alternative supplier or hedge service are worth it to them, and if we structure it this way, customers can make decisions for themselves rather than having somebody else make them on their behalf.

Second Speaker

I'm going to talk about how one goes about pricing default service. I think the states that have priced default at a wholesale or spot-market rate have erred. Instead, default ought to be set at the retail market price, to see whether the market is viable and whether retail competition can exist.

My remarks are directed towards pricing default service for residential and small commercial customers, who use less than 10,000kWh a month. Big customers don't need default service except perhaps for a couple of months when they're negotiating their contracts, although in most states that already have competition—like Pennsylvania, Massachusetts, Rhode Island, and California—the large customers had contracts arranged in plenty of time, so they weren't worried that their lights were going to go out.

The policy objective we're encouraging regulators to think about is using default service to smooth the transition to a fully competitive market. In other words, default service isn't something that will always be there, becoming a class of service of itself, but is a bridge from the regulated world to the competitive world that will keep small-use customers happy.

Default service shouldn't undermine the opportunity for the retail market to take off. It shouldn't create or perpetuate market power. If you simply hand default service to an incumbent utility that has the right to a generation affiliate for some period of time, as New Jersey has done, even with effective codes of conduct you are giving the provider, who already has a strong retail market presence, a continuing co-dependency relationship, making it difficult for the customer to see any reason to break away. I would allow incumbents to be arm's-length bidders, but not designate them as the default provider right from the start.

Another objective is that the default rate should be workable and fair, and in the event that there isn't retail competition because the margins are so thin, the default rate should collapse back into some sort of ordinary regulated rate, maybe using market indices as a baseline. I hope it doesn't happen, but I recognize that it's possible that we may ultimately find that small-use customers are not a viable retail market.

Thinking about how one best prices default service, we started by asking what would happen if there was no default service. What rate would small customers pay? Collectively, they would pay the average retail rate, distinguished from the spot market rate in that competitive suppliers have marketing and customer acquisition costs that the incumbent utility does not have. If you move immediately to a fully competitive market, where every customer has to choose on Day One, competing suppliers would incur marketing costs to attract customers to their respective businesses. The average retail market price would then be the wholesale spot market price plus the average cost of acquiring and retaining a customer.

When I look at the way many legislators and regulators are pricing their default service, I can only conclude that they don't really believe in markets for small-use customers. If you believe in retail competition, there's no reason for default customers to pay less, on average, than customers who shop. If you believe in markets, why do you want to price default service at the wholesale spot market price, which is always going to be below the rates that those who do go out and choose would have to pay? Why undermine your market from the start?

Another question is whether default customers should pay the same as those who shop. In other words, should default customers, on average, be paying whatever the incremental retail cost of acquiring and keeping a customer turns out to be? Oddly, I think a lot of regulators are very skeptical as to whether there should be retail competition. They pay lip service to it, but in fact are doubtful that customers really want to accept competition, so it's best to provide a comfortable world that doesn't look too different, where they continue to get billed by the same entity, where if they don't choose, it's okay because there's nothing pushing them to make a choice.

Regulators feel they have to promise significant up-front benefits to small-use customers. Decreases designed into the initial rates are fine, but there's an effort to keep padding low-use customers by giving them a comfortable, low-rate, default option, so that they don't have to bother making any choices. Some regulators even say, "Why not just aggregate them as a group and let them live with the wholesale rate? If there's demand for green power, or some other niche, customers will choose it, but the bulk of them will simply stay in this aggregated class." Surely an effort should be made to find out how viable competition is before just declaring that it isn't possible in this way.

If you're going to offer default service —and, politically, you probably have to offer it—it shouldn't be handed to an incumbent, but should be put out to bid. There are two different paradigms you could use for that bidding system, and one is much better than the other. The Type One bidding system simply asks, "What do you bid to serve this aggregated small customer class?" The lowest price would win, and you'd expect to see prices slightly above wholesale. That excludes something you are trying to capture in Type Two bidding, in which bidders are asked, "What would be your bid on a kilowatt-hour basis, to serve default customers at X cents?", and the regulators would set X at the average retail price.

We believe bidders would look at the average retail cost of serving customers and would be willing to bid the wholesale price plus some amount up to the cost of attracting and holding a customer at retail. How do you find out what that price would actually be? There are two ways: One is by looking at the states that already have competition, like California or Pennsylvania, to see what the retail premium has been. The other is by hiring your favorite econometric consulting group, who will come in and tell you what the average retail markup has been.

Our observation is that the cost of acquiring customers is 50-150 mills, so that you would expect bidders to bid wholesale spot market price plus something up to, say 100 mills, for the right to serve the aggregated class of customers. They're willing to bid this because they are being handed an aggregated group of default customers without the need to incur the retail cost of marketing and retention.

If you use Type One bidding, you're going to have default customers paying less for generation services than the shoppers, which isn't right. If you use Type Two bidding, which I recommend, you're going to have default customers and shoppers paying the same average rates for both generation and distribution. The money bid for the right to serve default customers is turned into a credit for everyone, both choosers and defaulters, against either stranded costs or distribution rates in general. (In Pennsylvania, even though they tried to get the right paradigm, they've done two things that are probably errors. The first is they've set their retail market premium too high, at least for some of the utilities. The second is that the retail market premium stays with the incumbent utility; it doesn't flow back to customers.)

My last point is that a content component ought to be taken into account in the default service, which is to say that the resource mix should not simply be the lowest cost, i.e. the dirtiest one. Default customers should get the kind of mix they have an interest in, which should have some green sources in it. If they want something cleaner or dirtier, they can choose accordingly.

Third Speaker

My starting point is that we make a lot of assumptions about restructuring and competition that may or may not be accurate. There's an assumption that choice will be offered to all or most customers and that it will be a good thing, but there's some reason to be concerned based on the experience that we've had in deregulating similar network industries.

For example, in natural gas, there's been a big difference between the benefits to large customers versus small residential customers. A similar trend exists in long-distance telephone prices, which have come down very sharply since divestiture, mostly to the benefit of non-residential customers. Residential customers make little use of long distance, and the rates for local service have gone up by about as much as long-distance rates have come down. Deregulation of pay phones in Massachusetts resulted in a rate that went from 10¢ to 35¢ in less than two years. Cable television prices, in the first year of deregulation, went up at 3-4 times the rate of inflation.

There are similar forces in the electric industry. What we've already heard is the worry that the margins for the commodity service are not enough to cover marketing, credit and collection costs. There will be efficiency gains from competition in the generation industry, but they will be outweighed by the transaction costs that the previous speakers quantified. Even in the run-up to restructuring, the price gap between residential and industrial service widened, beginning a kind of market segmentation with special deals for very large customers to the detriment of small customers. Potential competitors are saying that they're going to segment the residential market—as one marketer put it, there's choice on both sides. Market segmentation is a pretty standard feature of competitive markets, so it may be that most residential customers will not in fact have a meaningful choice. The importance of public policy in this gigantic experiment is to protect customers.

A quick word about who should provide default service. Just about every state that has acted so far has introduced some form of bidding, which obviously makes sense as a way to get market benefits to residential customers. Many states are also regulating prices—the most extreme examples being Connecticut, which has frozen the gap between residential and industrial prices, and Massachusetts, where the default price is set at the market average. The measure of success of the restructuring enterprise from the residential point of view is what happens to prices, not whether there's choice. The consensus on restructuring in states that have enacted it so far has been that there will be benefits for all customers, but what if there's no choice that results in lower prices?

It seems to me that from an efficiency point of view, restructuring is only a success if efficiency can be increased enough to bring generation costs down sufficiently to cover marketing and transaction costs. If it can't, perhaps residential electricity service really is a natural monopoly. One thing we shouldn't do is rig the market in advance by raising prices, as they did in Pennsylvania, where there was a non-discounted price freeze for non-shoppers, leaving room for competitors to come in and undercut this overpriced electricity service. To me that's not successful competition, at least for the residential customer.

Competition is a tool, not an objective. We have collectively hypothesized that the regulatory price is higher than whatever competition will provide, but we need to protect customers in case that's not so. We shouldn't punish people who do not, or who cannot, choose by making them pay higher prices. The program I would propose is to bid the commodity at wholesale, then track prices by class of customer to make sure that the benefits of competition are flowing to residential customers, not only to the big users.

Let me end with one hopeful note from a low-income point of view. Massachusetts has a separate rate for low-income customers, so it's easy to track their load. What's interesting is that all residential loads are relatively flat during the day, when the medium-sized commercial loads are peaking. So if you put them together in some way, you flatten the load. Interestingly, low-income load starts to increase a little later in the day than general residential load, so that there would be some advantage from the commercial customers' point of view to aggregation with the low-income load.

Fourth Speaker

Having the luxury of going last, I thought I'd provide some context about what we are trying to achieve in restructuring retail electric markets. Sometimes I'm amazed that, three or four years into the debate, we are still discussing the benefits of competition, which is arguably the most important way to enfranchise residential and small-commercial customers in the marketplace.

The previous speaker said he's not willing to assume the benefits of competition, but I don't think you have to assume the benefits. It's easy to go back into the literature and look at experiences in other industries, such as natural gas, airlines, trucking, and telecomm, that have gone through a restructuring over the last 15-20 years. There are a couple of common characteristics. One is that if you compare the expectations at the onset of restructuring to what actually occurred, you find savings greater than anyone anticipated. The other is that once competitive forces are unleashed, you see innovation emerge in a myriad of unpredictable, but usually desirable, forms. Perhaps the best example of this is telecomm. If you go back to the divestiture of AT&T in 1982, the debate was largely about bringing down the price of long-distance calls for consumers and businesses. Today, the debate is about local prices, about cable, about wireless, about high-speed transmission—everything but long-distance prices.

Since we have these experiences, one would think that history would be a good teacher and we would follow its lessons in the electric industry. Yet in practice, we seem to have a great deal of trouble applying these lessons. In Massachusetts, Rhode Island, and California, I would argue that the experiences of competitive entry into residential and small commercial markets to date have been abysmal failures. Why?

One reason is that there's been a sometimes cynical manipulation of the process by the incumbents, with default service prices often creating insurmountable barriers to entry. Another reason is a pervasive belief that we can micro-design the industry to get the right answers. We've seen this at work in wholesale markets, which are obviously critical to retail success, where operation research types permeate the debate, trying to design the perfect market. I think we'll end up in the same situation here—we'll design the "right" price and find that there's no marketplace for residential or small commercial customers, and none of the benefits that we've seen in other restructured industries.

All of this just brings us back to the question: If it's so simple, why aren't pro-competitive solutions for default service being embraced in states around the country? Fundamentally, it's because it's relatively easy to model static efficiencies, but difficult to model innovation and the dynamic efficiencies that are at work in every marketplace. They're here for the taking in this industry—there are technology benefits, time-of-use pricing, green products, bundled services, and so on. We don't yet have any idea how they will emerge, but we'll never find out if we don't put in place a default service pricing structure that facilitates markets.

Discussion

Question: Suppose you didn't have default service. What would people pay? On average they'd pay the retail price, but you'd have tremendous range, because these products are all bundled with lots of other kinds of services. Why should the standard default service be the average, instead of the lowest cost option available?

Response: Type One bidding has no cost of marketing to the customer; it's the commodity price plus whatever it takes to maintain a dialogue with a distribution company to keep track of your customers on a particular day. There's no cost of reaching the customer, such as the expense of an internet site or sending out mailings. We want a dynamic market, just like we want a competitive wholesale market, where the commodity costs themselves decline through operational efficiencies. Regulators have to describe a particular level of service, then go out and take a look at what the average retail price is for offering that particular package of services. It's like groceries; I can't buy groceries at wholesale, I have to pay retail prices, but there's a competitive market out there with a range of retailing costs. I don't want to start at the commodity standard, I want something that has a retail cost built in. It may just be the cost of the most efficient provider, although I'm not sure the market has developed enough for us to know much about who is the most efficient provider. We should encourage retailers to incur the cost of making their message known to the customer. It might be really minimal, maybe you just have an internet site and the customer will find you, but I would rather see the market create that than have the regulator just assume that's the way it's going to be by setting the price at wholesale.

Comment: I disagree with the notion that basing the commodity on wholesale supply somehow subsidizes default. If customers are served at the spot-market price, there's still competition in the wholesale market, where the ISO is continually conducting an auction. The discussion today is really about whether we should focus our redesign efforts on making sure that middlemen—who want to get between the spot market and the customers—survive, which would increase costs, in particular to residential customers.

Comment: I believe that there are certain benefits inherent in a dynamic market that you're not going to get from default service. Price is very important, but an interesting phenomenon that we're already seeing in the market is a green component. Five or ten years ago, we didn't think anyone would pay a premium to buy green power, but in fact they're doing it. Also, there are going to be very serious consequences if we mess this up, and we're most likely to do that by increasing the market power of incumbent monopolists by giving them market share up front, pushing way out into the future the time when we'll see a dynamic competitive market for this segment. It's very important that we take care of the market power issue, and it's worth paying a premium to do so.

Comment: Ideally, we wouldn't have default service, but that's not possible politically, so the next best thing would be to offer default for, say, 18 months, after which you're cut loose, and if you don't choose a choice is made for you. My fear is that if you start off offering the commodity price with some very slight additional cost, or if you simply give default service to the incumbent, it becomes a political impossibility ever to end that service, so you'll never see what kind of a market might have developed. Another point is that having a competitive retail market is part of creating a competitive wholesale market. I would like to see retail competition get going, because an added benefit of having retail competition is that it creates additional diversity of participation in the wholesale market.

Response: Why would you ever boot people off the system? It's interesting to hear people say, "There are going to be great benefits from competition, we're going to get innovation and new services, but if you offer the commodity, we'll never get them." To me that says the benefits aren't really there. If there are any benefits from value-added services, customers will choose them. What we're really talking about is how much customers, especially residential customers, will have to pay in order to access the benefits of a wholesale market. If you say that access will not be made available through the distribution companies, which have scope economies in the transaction costs, you are looking at about a penny a kilowatt hour, so transaction costs are a big problem in the short run. My proposal would be to serve them at the wholesale spot-market price plus a credit for customer service costs that encompasses the savings from not selling the commodity at retail. I don't understand why market power is an issue here, because the wires company is not in the generation business anymore.

Comment: Massachusetts began with a default service and a safety net service to separate the won't choosers from the can't choosers. Then it started trying to figure out who was going to be eligible for the safety net service. What does it mean that you cannot choose, and who is going to decide? Is the regulator going to have to step in and adjudicate every single case about who gets the safety net service? Finally, they just threw up their hands and admitted there is no practical way to make the separation.

Question: There is another item of commercial value, namely access to customer information. Does the customer recoup some of the benefits of providing the incumbent utility with continued access to that information, which potential competitors don't have?

Response: In Maine they are doing Type One bidding, and are going to pool the two or three lowest bidders for default service. But it will continue to be billed to the customer by the distributors, and somewhere on the bill will be a little notation saying, "The wholesale providers of this mix are Company A, Company B, Company C." In other words, the value of maintaining a link with the customers is being held by the distribution company, not the default providers. So, even Type One bidding can be done incorrectly, because Maine is not capturing the value of somebody bidding to have the right to the customer interface.

Response: The demographic data that the distribution company has—and they collected a lot of this in the days of demand-side-management research— may or may not have commercial value. The data of real value is the usage history, which is very sensitive information, so the policy is only to release it to people who are developing bills. To the extent that it has commercial value, nobody is capitalizing on it.

Response: I've had enough discussions with vertically integrated utilities to know that retaining customers has value. The CEOs will tell you they haven't yet figured out what that value is, but they don't want to create a default service pricing structure in which, by the time they have figured it out, someone else owns 99 percent of the customers.

Comment: One way to characterize all of this is that there are markets for two different products. One is physical delivery of the commodity, and the other is value-added services of all kinds. I would argue that physical delivery is a natural monopoly, and we should charge what it costs, namely the wholesale price. Then there are the value-added services, which I don't think are a natural monopoly, and, for a lot of reasons, it's desirable to keep the regulated entity completely out of those. They're potentially very competitive businesses, and are where the dynamic efficiency gains are going to come from. Implicit in all this is what economists would refer to as an infant industry argument—if we can get the industry running, it'll turn out to be wonderful, so we just need to subsidize it in order to get it going. But there's a difference of opinion about whether or not this really is an infant industry problem. If it is, you would pass the wholesale price through to the customer forever, but the subsidies for value-added services and new entrants would only be there for a short period of time.

Response: It seems to me that the distinguishing factor between this case and a true infant industry is that here we have a developed industry that is monopoly-based, rather than a new technology that's trying to enter without an established market. So we have a different dynamic from a public policy standpoint in making sure that we address the problem of incumbent market power. That's a dynamic that's difficult to wrestle with, and it implies that you have to make some choices that might be sub-optimal in the short run from an economist's standpoint, but which will hopefully lead to a market structure that will provide optimal economics in the long run. To me that's the tension in this debate.

Response: One difficulty with the infant industry argument in international trade was that the infant never grew up, so the subsidies never stopped. We've been using the concept of transition quite often, and I would make the point that oftentimes transitions, like infant industries, never end, and things that are sold on the basis of being transitory aren't transitory at all. Two examples are fuel-adjustment clauses, which are still present in many tariffs decades after their original rationale—Persian Gulf crude going from $5 a barrel to $35— disappeared, and price caps in telecomm, which were sold as a transitory measure, but are now a permanent part of the landscape.

Comment: In response to the remark that the wires company could be recognized as a natural monopoly and should continue to be regulated because it can extract rents, I don't see how we can argue that the incumbent has any market power in the commodity market. In fact, the whole notion of raising the price in order to induce competition is analogous to the market power that might be exercised by a utility that could influence the market price for its captive customers. I'm struggling to understand how it is we're equating market share with market power.

Response: To clarify, in the Type Two bidding system, which raises the apparent price of generation, the credit gotten through the bidding system flows back to the fixed portion of the customers' bill, so we're not looking at an absolute price increase. On market power, Central Maine Power, for example, has been prohibited by legislation from selling generation services to more than a third of the load, and they have had an aggressive legislative agenda to increase that. Clearly their aim is to be in the generation business and to serve as many customers as they can persuade the legislature to allow. They're also looking to see what other affiliate businesses they might be able to enter, including convergence with other types of utility and telecomm services.

Response: One comment on incumbent market power: We're hooking up generation all over the country in areas that we feel are in need of supply, and in negotiating interconnection agreements we've found that where the utility has decided that they want to get out of the generation business, we quickly get an agreement. But if the utilities have generation affiliates, it takes forever to negotiate the interconnection agreements, to get the studies for interconnection done, and so on. I think that market power is being exercised on that end. Won't it be the same with respect to companies that are keeping the retail merchant function? Those that want to stay in and continue to own customers are going to create the kinds of impediments that you're seeing on the interconnection side, and those that have shown a willingness to exit the merchant function will facilitate the marketplace.