

**Harvard Electricity Policy Group
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RAPPORTEUR'S SUMMARY*

Session One. Retail Competition: Should Markets Be Bifurcated Between Core and Non-Core Customers?

While much of the impetus for retail competition came from large, industrial customers, those states that opted for retail competition generally decided to provide all consumers with the opportunity to choose their own supplier. While many large users have availed themselves of the opportunity to shop for suppliers, most small customers with a choice have simply remained on standard offer or default service from the local incumbent. The behavioral dichotomy between large and small customers has led many to conclude that rather than continuing to “swim upstream” in trying to get small customers to shop, the better approach is simply to develop policies that reflect the realities of the marketplace. Some retail competition states either have, or, are actively considering, switching to a core/ non-core approach in which some customers will have the opportunity for continuing to shop for suppliers while others do not. Are core customers self selected, or are they deemed core by some specified characteristic(s)? If so, what characteristic(s)? What opportunities, if any, should be provided to non-core customers for arbitrage between the two markets? Can the same entity supply the core customers and the non-core customers? If so, how will their supply portfolio be overseen by regulators (i.e. for prudence for core customers, for cross-subsidies from core supply to non-core supply, for portfolio allocation between sales in the two markets)? How will cost allocations between core and non-core customers be affected? How will stranded benefits funds and purposes be handled between core and non-core? Is the core non-core dichotomy sustainable over time? Economically? Politically?

Introduction

I will pose several questions to the speakers. What do we mean by core and non-core? What is the construct? Does the non-core get to choose to be non-core in the first place, or is it mandated to get out

of the core? Can it return to the core, and if so when and how often? In the end, the only true metric is the end-use consumer. Will this work to provide reliable and affordable energy? Would it be economically and politically sustainable? Without regulatory assurance that the end-

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

users will pay off the major facilities that are supposed to last 20-30 years, why would anyone invest? This is really the question of retail open access and the non-core is a subset of that in the core/non-core model. But it is a dual universe because the non-core is in an open access mode and the core in another, presumably more regulated mode.

Market rates presumably fluctuate above and below the regulated or average rates. What happens if the fluctuations are quite volatile or stay sustained over a period of time? If prices are above average cost, investors are happy, but not so the non-core customers.

If customers want to return to the core, will there be legal structures to prevent them, or to set the terms for coming back? How will a state legislature resist the power to change the rules if customers are unhappy? And if there is a reserve requirement for purposes of reliability, what does that do to the spot or market prices?

The core/non-core concept is not necessarily limited to the retail open access states. For example, in my regulated state, some of the big customers were let out in 1996. For a while, things were fine and then the western energy crisis occurred. Even though the big customers had signed agreements to stay out at least five years and pay market rates, they wanted back in. There were long hearings about whether this was an emergency and that regulators should grant them relief.

It is often said that big customers are sophisticated, but as a regulator, I had people on the stand who were in charge of large corporations' purchases and did not know about electricity and had not hedged. We might argue that people will know better the next time.

Speaker One

In my state, the availability of below-market standard offer service has acted as a significant barrier to the development of competitive markets. We began with the legislature setting the price. They did their best, but they guessed wrong. In June 2000, the state utility commission uncoupled rates for standard offer and default service, allowing the latter to be priced at market rates via competitive solicitations. When customers see the difference they get nervous and politically, this was extraordinarily difficult. But we knew that we had to see some market prices if our market was going to take hold.

In 2003 we said, "Competition is the means to an end, that end being maximizing consumer welfare. Maximizing consumer welfare means minimize long-term costs to consumers while maintaining the safety and reliability of electric service." We also said, "If consumer welfare is maximized with very few customers switching to competitive supplies, it is not a policy failure as long as there is free choice and there are no artificial impediments for either suppliers or consumers."

As regulators, we have directed the discos to make available customer lists; directed a pro rata allocation of partial customer payments between disco and a competitive supplier; and are now working on a proceeding for each electric disco to ensure that the appropriate level of default service-related costs is included.

This is not as easy as figuring out what should be in rate base, but we are committed because then consumers will have an apples-to-apples comparison.

We have implemented a quarterly default service procurement for large customers and have stayed with six months for residential. We have incorporated default

service rates that differ by LMP. When rising fuel costs increased the deferrals because of our standard offer rate, we created an adjustment process.

From our perspective as regulators, we have taken steps to jumpstart the legislature's mandated programs; implement initiatives to encourage the development of markets; embrace the core/non-core approach; and implement initiatives to bring benefits to the wholesale market.

The legislature has a bill that would aggregate residential and small customers and assign them to licensed supplies in blocks. The winners of each descending clock auction would provide basic electric service for 3-year time periods. Customers would be given the opportunity to opt out.

When we go to a fully competitive market in March 2005, we will review the data on customer behavior. Let us see what happens because a bottom market failure where most customers receive service below cost is premature. There are regulators who think that the marketplace plays an important role in consumer protection and that we need to stay in the fight.

Speaker Two

What is California doing to address core/non-core issues? The governor's top priority is resource adequacy – literally, a requirement that all LSEs procure or contract for 15 percent planning reserves by 2006. The state is resource deficient and still faces the prospect of a fiscal crisis. Since the problems tend to be locational-specific, this has a direct bearing on core-non-core and we really must consider the locational aspect of resources and how they can be delivered into the market.

A second priority is transmission. We must find a way to reduce congestion costs because of significant under-investment over the last 6-7 years and find a way to expand interstate transmission. California recognizes that its policies will have impacts on its neighbors, and likewise that their decisions will affect California's ability to shape its policies.

A third priority is wholesale market reform: an open, transparent, competitive procurement process at the wholesale level. The PUC is reviewing the utilities' long-term procurement plans that must consist of a mix of short-, medium- and long-term contracts hedged financially.

A fourth priority is rate relief. Obviously, California must maintain its global competitiveness and increase western natural gas supplies.

The next set of priorities consists of retail choice, direct access, renewable energy, energy efficiency, research and development, technology transfer, dynamic pricing and advanced metering. The challenge for policymakers is to recognize that the priorities are interrelated: for example, as we think about resource adequacy and the design of a capacity market, it has a direct bearing on our ability to actually implement a core/non-core model. California has suspended direct access until the long-term contracts are paid off, meaning that between 2011-2012, large customers will have the right again to shop for a competitive supplier.

With respect to retail choice, California will reintroduce core/non-core, only after ensuring sufficient resources and transmission and a mechanism to ensure that no cost shifting can occur between small and large customers, and no new stranded assets are created. The governor vetoed earlier legislation because stakeholders could not reach consensus on eligibility; customer aggregation; exit

fees; and so forth. Nonetheless, the commissioners are still talking and hope to learn from the work done in Massachusetts, Maryland, New Jersey and New York.

There is talk about creating a third customer category called “core elect” – the qualifying customers who have the right but not the obligation to choose. This would provide a relief valve or mechanism for defining and expanding the qualification criteria but serving that load at a short-term market price. Presently, however, the day-ahead market price is distorted as a result of the long-term contracts. Other issues that California is discussing include: structuring a tradable capacity market to encourage investment; a POLR option; and pricing and managing the risk premiums.

People argue that customer choice has failed because there is no benefit to switching, there are numerous market barriers, or the service providers themselves have not communicated. However, California is just finishing a two-year, statewide pricing pilot, the largest of its kind in the US. One of the preliminary conclusions is that within five years, residential rates can provide a price responsiveness of 1,400-3,000 MW of peak capacity reduction. Another is that customers appear to prefer dynamic rates to existing ones. The price elasticities were consistent over the last 30 years of research, which say that customers can respond to information when it is made intelligible and understandable. It should come as no surprise that if you do not understand how your electricity use is measured and priced and you do not trust the accuracy of your bill, there will be no significant switching.

Because consumers have been able to understand their cell phone plans, time-differentiated pricing does make sense. Consumers can also understand that a core/non-core market structure

accompanied by information and the ability for frictionless movement can lead to making rational choices, but we need policies and infrastructure to support the free flow of interval data between market participants, such as advanced interval metering and simplifying and overhauling tariff design.

Speaker Three

The heart of the New York Public Service Commission’s position on competitive energy markets is that as long as there is confidence that the wholesale market in New York is competitive and properly mitigated where it is not deemed workably competitive, there is no reason to bifurcate the market. In other words, we believe that the day-ahead and real-time wholesale prices in New York are just and reasonable for all customer classes. Just because smaller customers are not yet realizing the full benefits of retail competition does not mean we should stop trying. There are safeguards in place. The issues of stranded costs, cost shifting among customers and market incentives for the construction of new power plants must be addressed as the wholesale and retail markets develop, recognizing that future course corrections may be required.

New York’s transition to more competitive electricity markets began in the early 1990s. At that time large customers attempted to bypass utility commodity purchases because they were drawn to low wholesale prices or cogeneration proposals that could lower their costs. Smaller customers, in the form of municipalization, studied bypass options as a way to lower costs. In 1993, the state’s public service commission first allowed large customers that could demonstrate a willingness and ability to either install their own generation or leave the state due to energy costs to negotiate a discounted rate or flex rate.

In 1996, the commission issued its vision statement, calling for expanded consideration of competitive opportunities beyond large customers, and asked utilities to file a plan including but not limited to: retail choice for all customer classes; divestiture of generation assets; and recovery of stranded costs.

From 1997-1999, the commission approved the restructuring plans, with modifications of individual utilities. These orders reflected different approaches to the utilities' territories in terms of the timing of retail choice; back out credit designs and amounts; the role of the utilities; and portfolio design for smaller and larger customers.

In other words, New York took an administrative, not a legislative, approach to restructuring. This allowed for different concepts to be tested, based on customer needs, market realities and the utilities' circumstances. However, an unfortunate circumstance was the lack of consistency for ESCOs interested in operating in more than one utility market.

The New York experience has shown that non-core customers are more interested in shopping for commodity where their local utility offered only a pass-through of market prices. Core customers were generally provided a portfolio of long-term contracts, shorter-term hedges and spot market purchases. Where spot market prices constituted a higher percentage of the utility's portfolio, there was more interest in marketers and more migration. Migration was generally slower in areas with utility fixed-price offerings. However, many factors beside default service design contribute to migration rates.

For example, in one utility territory, back out credit rates were 1 mill per kWh for large customers and 2 mills for small ones; a one-time customer incentive for migration to an ESCO was adopted; and

sales tax incentives were given to customers that chose marketers. As a result, nearly 70 percent of large time-of-use customers migrated to ESCOs, representing nearly 80 percent of the load for that customer class. This success is largely attributable to the sales tax differential. On the other hand, commodity costs for residential customers represent a less significant percentage of the overall cost of living and reflect the fact that the margin is not really sufficient to make it worth the acquisition cost of the ESCOs, unless the acquisition can be accomplished on a larger scale.

In a territory upstate, the largest customers paid the spot market prices and longer-term hedges were reserved for other customer classes. These hedges will be removed through time, based on decreasing levels of demand.

In still another service territory, nearly 60 percent of the largest time-of-use customers migrated to ESCOs, representing 55 percent of the load in that customer class and nearly 6 percent of residential customers, representing 7 percent of the residential load.

There was no back out credit in another territory, but the utility did offer the purchase of accounts receivable to eliminate the uncollectible risk for marketers. There were no long-term contracts and wholesale price spikes were passed on, sending a signal to customers to manage consumption and/or look for a cheaper or less volatile product through the market. A "switch and save" initiative encouraged customers to investigate competitive options, with several marketers agreeing to discount prices in the first few months. About 24 percent of the largest time-of-use customers migrated to ESCOs, representing 50 percent of the load and slightly over 30 percent of residential customers, representing more than 37 percent of the residential load.

Lessons learned from these different approaches are that markets need consistent, uniform business rules for the exchange of customer information and revenues, and standardization and automation through electronic data interchange. Although the collapse of the wholesale markets elsewhere, accounting and finance scandals, September 11 and the August 14, 2003 blackout intervened the public service commission is now studying the ultimate role of the distribution utility and other barriers to retail market growth for small customers.

The vision is that over time, utilities will become primarily transmission and distribution providers; utility costs will be unbundled and assigned to competitive and non-competitive functions; and customers migration strategies may include auctions, purchase of accounts receivable and a transition of default commodity service toward a pass-through of short-term market prices for customer classes, beginning with the largest. Ultimately, ESCOs will provide hedges and utilities that enter into long-term contracts will do so at their own risk. Smaller customers will take greater control over their energy purchases and there will be varied product and service packages, including fixed rates, energy efficiency, distributed generation and bundled, electric, gas, water and telecom.

Arriving at this state will no doubt require advances in technology and further automation through real-time load control techniques and smart-grid applications, but the commission believes that customers will not be harmed by trying out the competitive options during the transition. The state will also strive to create a fertile ground for investment through its wholesale and retail market designs. The commission does not believe that the current state of the financial markets with respect to large-scale investments will preclude merchant funding forever. It is willing to examine

the benefits of customer funding for public policy purposes. Ultimately, competitive markets will best provide the state with the ability to react to changing market conditions, stricter environmental policies and the dynamic politics of energy.

Speaker Four

At the time the state of Ohio passed retail competition, electricity rates ranged from 6.4-10.3 cents, which is a significant difference for the average residential customer. The idea was that competition would provide an opportunity for customers in the northern part of the state to benefit through lower rates. Another reason to deregulate was the desire to avoid the huge cost overruns incurred in power plant generation in the 1970s and 1980s.

However, the reason why deregulation has not yet resulted in significant retail rate reductions is the stranded cost payments that must be made through December 31, 2005. Ohio also has a problem with air pollution and clean air act compliance. Will these environmental costs be passed on to customers if the state returns to some form of regulation?

The key question is what happens at the end of the present transition period. Personally, I think we might be better off giving customers competitive options. Although competition is working more slowly than anticipated, nevertheless, it is working. As we near the end of the market development period on December 31, the law requires that a competitive bid take place to provide POLR service.

The auction process is somewhat similar to New Jersey. The commission will study FirstEnergy's proposal for a rate stabilization plan charge, with the hope that the competitive bid process works to bring customers lower rates. A competitive bid could bring diversity in

both the short and long term. By doing so, it would avoid reversion to ROR regulation with unclear incentives to build power plants cost effectively.

Recent power plant generation in Ohio is gas-fired and as a result, prices have risen. The only way customers can hedge against these prices is to engage in aggressive DSM and to develop demand response rates. How can we get new generation in place under a competitive regime? Have a wholesale bid with a mix of short- and long-term contracts. Short-term bids would manage migration risk, while your longer-term contracts would enable developers to approach Wall Street with a guaranteed revenue stream. As more customers switch to retail providers, you chip away at the pieces that are on the short-term side so that you protect the integrity of the long-term contracts. This is one way to guarantee you get construction into the state without returning to ROR regulation. The benefit for customers is that to some degree it is capped.

There has been talk about IGCC because Ohio relies largely on coal-fired capacity. You could set aside a slice of your portfolio standard for whoever can bid for the best price of IGCC, and can do the same to capture biomass and wind and to build in energy efficiency.

Other ways to reduce rates and encourage efficiency could come aggregating residential customers and offering programs such as interruptible rates. A subdivision or an apartment building might have a distributed generation unit. Just like the industrial customer that pays a lower rate for interruptible, a utility could negotiate with the residential customer.

Question: If you have long-term contracts in the portfolio that determine the POLR price, how do you guarantee that the customers will be there for 15-20 years?

Response: The likelihood that there will not be 10-15 percent of the customers taking POLR service is not very high. You would have to get creative about how to pay for the cost, but it would be a type of guarantee in the same way that IPPs enter into contracts for guaranteed power.

Question: What happens if you sign a 20-year contract for five-cent power, gas goes to two dollars and everyone leaves POLR service?

Response: I am focusing on the idea of a pact among the regulators, the utility and the party building a plant, where, by approving the portfolio, the regulators have guaranteed that the price would be recovered. That is the risk you have with any technology or anyone who builds any power plant at any time. You diversify your portfolio so that you can offset high prices with low prices and come up with a reasonable, affordable price.

Discussion

Question: If you have a capacity market that includes a reserve requirement, how do you get the price signals that spur investment if there are no guaranteed non-core customers?

Response: The starting point is that resource adequacy is a public good; it has to be paid for by all customers; it is an obligation imposed equally on all LSEs. In and of itself, a capacity payment is insufficient to build new investment. In designing the capacity market, the requirement is to have a planning reserve margin and to do it enough in advance in order to provide a price signal that indicates when there is scarcity based on the anticipated resources being made available. Providing the price signal also encourages demand-side resources on an equal footing with the supply side. It allows new business models to emerge

that capture the value of demand. Another objective is to treat imports and exports equally and then extend that approach to the entire western grid.

Question: How do we protect the small customers who cannot know the risks they face when they switch to a competitive supplier? How do we ever get rid of utilities' obligation to serve? Fundamentally, it is unfair to investors that utilities have an obligation to serve, but customers do not have an obligation to buy.

Response: In Ohio, in a few instances, another supplier purchased the customer base of a defaulting company. It is important to do everything to educate customers about competition and the available choices. And marketers must register with the utility company. A web site can be used to compare the varied ESCO offers. I believe that as the markets grow stronger, suppliers will also, and that there might be IOUs that would be happy to leave the POLR responsibility.

Response: New York protects the small customers by putting resources into customer education. We tell them about their choices and how to make educated choices.

Response: The original reason to set up monopolies was that electricity was a product that could not be delivered more competitively. Today, we do not do away with the obligation to serve, but we begin to refine the definition of that obligation along the lines of service and delivery to meet the needs of an evolving competitive market. The airline industry offers an interesting analogy with respect to obligation to pay. We do not say, "I will not build a new plane unless you, the customer, agrees to fly my company for the next 30 years." Or, "If you want to fly from Los Angeles to Phoenix, you must wait until we build a new terminal because we are unwilling to share it with anyone."

Or you travel by car instead of flying and receive a bill for what the airline thought you would have used anyway.

Response: I am not suggesting that where previous commitments and investments have been made on behalf of ratepayers that they are no somehow exempt from paying them. But if you change the terms of the deal, everyone needs to know going forward.

Question: We have had about 10 years of experience with customer choice. There has been no jurisdiction where residential customer choice has been wildly successful, at least in terms of customer switching. Do these customers want choice? How do we know? Does it matter whether they want it or do not?

Response: Anecdotal evidence in New York is that customers want to know the choices and they come prepared with a long list of questions. Our new Office of Retail Market Development does not only tell people what their choices are. For example, it is looking to expand the public benefits program to educate people on energy efficiency.

Response: Part of choice is exercising it and part is not. It matters what customers think. Education is power. The goal of a consumer advocacy agency is to give as much information as possible so that people can – or can choose not to – exercise choice.

Comment: We cannot define success in and of itself as aggregation or an auction.

Question: You need a healthy wholesale market before you can get a good retail market. If an Enron occurs or a supplier defaults, as long as customers have an alternative, it does not really matter. But today's alternative is the utility or POLR. So how do you give utilities an incentive to go to a competitive regime? Many have

old plants that they want to keep running. Wall Street is also now involved.

Response: Regulators are not doing everything that everyone wants. They are cautiously aggressive.

Response: It is the regulators' responsibility to remove any disincentives to actually embracing the competitive market and at the same time, to present new opportunities for revenue growth and maximizing shareholder wealth.

Question: If you want new capacity, someone, somewhere, must sign a long-term contract. How will California deal with this issue?

Response: In addition to the capacity market design and the obligation for resource adequacy, the utilities have submitted their long-range procurement plans. There is a series of pending offers for short-term (1-3 years) capacity requirements where the ISO will take a very active role in defining the type of product, the location, the duration and the quantity that it needs with load-constrained pockets, and also a 10-year offer. Similar offers will go out for renewables, all of which collectively are designed to attract new investment back into the market.

Comment: If you want to collect costs that are above market, you do not collect them from someone who has a choice not to pay them. The easy answer is wires charges.

Response: One example is that California has a public goods charge that goes into a fund for renewables, qualifying payments and supplemental energy payments, or SEPS, that are meant to cover the above market price of these renewables.

Response: Ohio's deregulation has legally separated generation, transmission and distribution. How would you put a wires charge for a supply option if the customers

do not all benefit from that particular option? When taking a portfolio approach, look at the long-term, in the same way that a utility files an integrated resource plan on a twenty-year horizon.

Comment: Looking to the ISOs should give us some answers.

Response: It requires the ISO to assume responsibility and exercise the authority to carry it out. In the past, ISOs have sometimes deferred to commissions on resource adequacy issues.

Response: For markets to be truly vibrant, some barriers must be removed from one system to another, while always remembering that reliability is of the utmost importance. Reliability is the best commodity a state can offer.

Comment: The more regulatory certainty, the more investment from both the generation and retail supply perspectives, because no matter who is serving the load, it will be there. However, we appear to be narrowing down what is competitive to strictly an energy market, while ignoring ancillary services and capacity.

Response: I do not think we should be relieving the central buyer system but should move on and get the demand curve right.

Question: In our service territory, shopping is working well because customers are saving about 15 million dollars annually and we are deferring about a billion dollars in subsidies that they will pay back at the end of the market development period. But who will build the next generation of baseload capacity in 2010-2015? Who will incent suppliers if the price that customers pay does not move to the marginal level and stay there?

Response: It is not just about building a plant, but about siting and transmission.

Question: What subsidies must we provide if we need capacity? If the only way you build an IGCC plant is if the government funds the subsidy, then we are again not dealing with how to build generation in a competitive marketplace and who will put up the dollars to do so.

Response: If you call low-interest financing a subsidy, then it is a subsidy. But you are looking at a way to reduce the overall risk of a project so that the cost of capital comes down and that helps to keep down the overall price of the generation.

Comment: There is vibrant retail competition in the UK and the 14-year transition into full retail competition there

has been very successful. In the initial stages of the market design, regulators separated the competitive market into a fully competitive section and a regulated section and transitioned the regulated part to full retail competition over an 8-10 year period. However, it is important not to substitute incorrect judgments for the preferences of the final customers. Can the UK mechanisms be implanted in the less successful retail jurisdictions in the US?

Response: I try to impress on staff that they need to look elsewhere to figure out what has and has not worked before they start from scratch.

Session Two. How Does Electricity Restructuring Alter the Real Costs of Risk?

Electricity restructuring changes the incentives of market participants. The new trading arrangements also produce new allocations of risk. This includes changes in the default assumptions for who bears what risks, changes in the institutional arrangements for mitigating risks and different tools for portfolio management to reduce the real costs of market volatility. Underlying risks may change, and the rearrangement of risk bearing need not be a zero sum game. The allocation of risk responsibility can affect real costs. When the risks do not fall on those with greatest capability to mitigate, real costs can be higher. In the absence of completely risk neutral market participants, the allocation of risks affects real costs as reflected in the willingness to pay to pass on the risks. Has electricity restructuring increased aggregate risk? Or simply reallocated risks that were already there? Have diversification tools and opportunities increased or decreased the aggregate cost of risk? How should we evaluate the risk impacts in the cost benefit analyses of electricity restructuring?

Speaker One

Long-term risk and its uncertainty greatly concern the investment community. Another concern is that rapid technological change causes anxiety about embracing any product or service that promises a transformative change. In a restructured world, the regulator is no longer the gatekeeper but is now the professional investment manager. Unlike the regulator who is rewarded for keeping the lights on – or at least is punished severely when they go off, the investment

manager is graded on the basis of a single criterion – the portfolio rate of return.

We know that investment in electricity generation assets requires patience, a long-term commitment and a tolerance for significant risk. It can take several years just to plan facilities and as we all know, many important assumptions can change during that time. For example, Energen has a \$700 million investment in a combined cycle gas facility that sits almost idle because changes in state legislation mean that the company cannot

get into the grid. Two more issues are changes in environmental regulations and fuel costs.

The professional money manager on Wall Street is being asked to ride out all this uncertainty, but is being graded every quarter. This is a mis-match. Consequently, the gatekeeper is inclined to avoid such investments unless the returns appear inordinately high. Money is most likely to come to the table when there are clear, persistent and significant shortages, something the oil and gas industry knows well. Then when everyone jumps in the result can be significant excess capacity. No coordination between the new and existing generation facilities, a lack of long-range planning and opportunistic behaviors result in more mis-matches.

I conclude that electric generation investments are likely to be less consistent and predictable in the restructured environment, first because of Wall Street's pattern of investment boom and bust; second, because that pattern is accentuated by the incentives of the investment advisers; and third, because the investments are likely to be unregimented, opportunistic and will not necessarily be a good fit.

As for transmission, its evolving regulated environment differs from the old, where the ratepayer is the investor and the state regulator is the investment gatekeeper. There is integration in the vertically integrated utilities and both planning and regulation are primarily statewide.

But now, the ratepayer is still the investor and the gatekeepers are the regulators from multiple states, plus the IOUs, the IPPs and the cooperatives.

FERC proposes independent transmission providers, with planning and administration being executed on a regional basis. This apparatus sits

awkwardly atop the multiple independent state regulator schemes, but is dependent in the final analysis on the state regulators to raise the funds from ratepayers to fund transmission system expansion and upgrades.

Although there is a plan to allocate costs proportionately to LSEs, in my view the financial last resort will be the ratepayers, particularly if electricity restructuring is anything like the natural gas experience in which LSEs came and went.

Are we better off with many diverse interests operating under the umbrella of an RTO, but no one has a hammer? Like any regional legislative body, the risk is that the RTO can become easily gridlocked. State regulators may not honor the sense of the RTO and if that occurs, needed system upgrades will not be built until costs are so high that the parties are forced by circumstances to acknowledge their common need.

Finally, the obvious, positive aspect of restructuring is innovation, since innovators are not attracted to a regulated environment. If there ever was a time that we need innovative thinking about how we generate and transmit electricity, it is now because our system runs primarily on hydrocarbon fuels that create significant environmental concerns.

Speaker Two

I will focus on optimum timing of new investments in the Nordic power market, using auctions and how capacity payments would affect the decision to invest in new power generation for the centralized investor. Prior to restructuring during the 1990s, there was some surplus generation in the system. However, this surplus is disappearing rapidly because of increased demand and not enough new generation. We face a situation with increased vulnerability in terms of both capacity and

energy. There is a lot of hydro but it brings some additional uncertainty; there is also less centralized planning and coordination. One alternative might be to introduce a capacity payment or an ICAP obligation.

Assuming a new entrant has already obtained permission to build, the challenge is to find the optimum conditions for investment. I also assume that the investor receives its profit from the electricity spot market first, but also possibly from a capacity payment. I have based my model on historical prices and loads from the Nordic market and assume that some renewable capacity will also exist.

I analyzed three scenarios: the investor only earns income from the energy market; then I added the fixed capacity payment which is the same regardless of the capacity imbalance in the system; and then I added a variable capacity payment that depends on the capacity factor.

According to real auctions theory, it is not optimal to invest until the value of investing immediately exceeds the value of waiting. This differs from what static net present value analysis because that would suggest to investors that as soon as the expected profit from investment turns positive, it would be at a lower level. As I add another dimension for the uncertainty in load growth, the investment threshold becomes more restrictive.

If I add a fixed capacity payment, the investor will also receive a capacity payment and the optimal threshold will be reduced as the investor's profit from investing shifts upward. However, the expected profit at the threshold is approximately the same as in the first scenario.

The picture changes with a variable capacity payment, in that the expected profit for the investor is now steeper as a

function of the load level in the system because the capacity payment occurs for high and low levels. Since the load growth is uncertain, this payment will also be uncertain. For the investor, it represents higher value over waiting for more information because of this uncertain capacity payment.

In conclusion, when investing in a restructured power market, the supply side faces a higher fractional uncertainty than it used to under the regulated regime where it was protected by regulated prices or tariffs, or may be regulated rates of return. At the same time, investors in new power generation can find it difficult to hedge long-term positions because the long-term markets might not be very liquid. This, of course, adds to the cost of hedging and prevents investments. From a systems perspective, we also know that several factors can distort the optimal formation of prices and therefore, the market participants' incentives for new investments.

Currently the Nordic market has performed fairly well in the short-term operations phase. Full retail competition seems to be working as well. However, it still remains to be seen whether the market can pass the long-run investment test. The focus is on developing a more flexible demand side and also on a mechanism to obtain operational reserves in the system. The idea is that the energy markets will provide sufficient signals for new investments.

Speaker Three

When we consider the question of increased risk, there is a certain self-selection bias: those who are negatively affected by deregulation speak louder and are better heard. And it is obvious that at the start, volatility occurred in places that were not used to it. It is also obvious that the traditional skill sets are not necessarily

the best to conquer the new learning curves. There are conflicts and dilemmas like the problem of traders versus engineers. Are the brilliant engineers who created this reliable system really the best traders or can they become the best? We must also consider the risks at the industry level and for consumers.

With the growth in infrastructure complexity, environmental risk became more severe, as did fuel risks. Now, fuel-associated risks can be hedged in the market, but the environmental and structural factors are not easily hedged.

If we identify the interplay between environmental and electricity supply risks, what can we do about it? In the investment world, you do not really hedge your gamma before you hedge your delta. In other words, you hedge your biggest risks first and then try to address the smaller ones. It appears to me that the infrastructure and environmental risks are probably the biggest factors in the total risk increase in the industry and the economy.

One answer is to make interruptible energy and demand response programs work, thus creating perfect markets. My policy recommendation is to make the interruptible energy tradable. RTOs could offer it, along with firm energy. Current technology is capable of propagating the RTO interruption signal to the retail level. Although there are no forward or spot markets for demand response, the unit-contingent contracts that exist in the market could allow people to hedge unit contingency along the forward curve. Being able to hedge physical contingencies is a step toward trading interruptible energy.

Unfortunately even in the unit-contingent markets, there are no uniform standards and RTOs are not offering them. But that could be changed. What if consumers could have an opportunity to prioritize

their usage during periods of interruption? You might not need operating reserves in the amount of the biggest unit, and a permanent demand response program would alleviate the congestion in load pockets. That could mean that you would not need to build more transmission.

The tradability of the interruptible product accommodates the long-term technology investment because now you invest in the technology that makes that manageability better and such investments are both smaller and better distributed than investing in a transmission line.

In terms of risk management, the spreads between interruptible and firm products would determine the investment needs in firm or interruptible physical assets. The mitigation instruments would become divisible, and conveniently tradable and hedgeable. Environmental risks would be better mitigated through partial hedges. Load pocket reliability risks would potentially increase.

In summary, the largest risk components should be mitigated first. The risk components should be identified, formalized and packaged in a user-friendly format. The identified risk components should be made tradable. Deregulation should be expanded since only deregulation is able to provide the efficient risk mitigation tools like interruptible energy trading. These are my policy recommendations.

Speaker Four

Risk and risk increases are just features of a market. There is no pejorative. There is nothing good or bad about them; they are there and you deal with them. If risk increases costs, the costs may or may not be justified by their benefits. The fact that I will conclude that risk has gone up does not mean I am anti- or pro-deregulation.

I think risk will probably go up in a competitive market, although we will have to get there to see. I definitely think the incidence of risk would shift from ratepayers where it now lies, to either investors in the generation, or to third parties primarily, although not uniformly. I am not surprised that the transition has taken so long. Everything we know about regulatory transitions is that they do take a long time and electricity is especially difficult. I think we need to pay better attention to the transition because it will be with us for a long while. In that case, risk is plainly higher during the transition and the incidents are very difficult to predict which itself is a risk.

In ideal markets, I do not care whether ratepayers or investors bear the risk, because we are building long-lived capital investments to generate power and selling them into a market. That is a very risky thing to do at an intrinsic level and is often obscured by rate regulation. As I have said, electric generation is very risky by its fundamental nature. I think that risk will probably be higher under competition.

First, there is a coordination problem in a system with huge interdependencies. Building a transmission grid and locating power plants on it are problems that change from season to season and even from hour to hour. Now you must coordinate it in a more decentralized way.

Another problem is that competitive markets drive product offerings by differentiating customers. Regulated markets value administrative simplicity; it is not efficient versus inefficient per se. It is just what you have to do in order to function in the market. So there will be more uncertainty in the product offerings that will translate into uncertainty in the value of the investments.

Rate regulation allocates almost all long-term risk to customers, with some going to investors. The analogy is that if you own a

building, you can rent it via a long-term lease to officeholders or operate it as a hotel. A long-term lease transfers most of the risk to the person who signs the lease with you. But if you operate the building as a hotel, and the offices are empty, you receive no money. If the economy is down you have to offer discounted rates or make it up in boom times, if no one is yet building a newer hotel next door. An ideal competitive market would have a mix of hotel-like office investments that could be directed to customers or to third parties that contract for the power and then sell it. You could pay for the right to bear the risk yourself and get a lower price in exchange for signing the contract. You could buy it on the spot market and pay a higher price because someone else is bearing the intrinsic risk of the power plant. If someone else is bearing it, price the risk high. If you are bearing it, you should receive a discount and let customers sort themselves out along those dimensions.

Because I think we will not be going there any time soon, it is more urgent to discuss where we are now. There is the potential for market manipulation; the complex physics associated with coordinating the grid; electricity cannot be stored; and the fact that the price you buy electricity at does not equal the price you sell it in a supposedly deregulated market. Why would anyone be surprised at a price spike when final customers do not get the price signal?

One other problem is that the system has very long-lived assets and thus takes a long time to adjust to the deregulated world. Regulatory uncertainty and concern about earning a decent return will slow the rate of investment and contribute to the length of the transition. I do not think we have a situation in which people say any change is bad, but there is a genuine and an unavoidable long transition in which the costs in the interim are worth paying attention to now.

Question: The one piece of the market that is missing is price responsiveness on the demand side. It only exists where there is a clear risk for the customers in not doing something to manage their own demand. Being shown the real-time price is not the same as paying it. Can we insulate end-use customers from all of the bad things that can happen in the electricity supply regime?

Response: You need a system in which customers can choose whether to bear real-time pricing risk or pay someone else to bear it for them. But in such a system, you would expect the average price of the person who bears it real-time to be lower than the price of someone who receives a flat rate. Then customers can decide individually if they want the security of a flat rate and if they are willing to pay a premium for it, or if they want to bear the risk themselves and save a little money on average.

Comment: In a regulatory environment, most customers remain insulated from the real-time price risk.

Discussion

Comment: I think it is a bad idea to use ISOs as procurement agents for capacity or renewable portfolios. The value of an ISO is in being a neutral operator of the market. Taking a position to solve a market problem will result in reducing an ISO's usefulness. I also think there is no way to insulate end-use customers from all of the bad things that can happen in the electricity supply regime.

Comment: In a regulatory environment, most customers do not remain insulated from real-time price risk.

Comment: RTOs reduce risk by performing security-constrained economic dispatch, for example. I think such tools must be factored into the scenario of risk

aggregation and the effects of restructuring. I think the creation of RTOs and the standardized market across a number of states ultimately will lead to a convergence in regulatory outcomes and procedures. I hope that convergence reduces regulatory risk, at least in the long run. To the extent that we can reduce or eliminate seams, investors will get a better index fund.

Question: What risk variables are we measuring? Cost of power? Price of power? Returns? When we say risk is increasing, do we mean that the actual shape of the distribution itself is changing so there are different probabilities associated with the outcomes as well? When we talk about the costs of managing the increased risk, if everyone is risk-neutral, would we just be shifting things to people or do not understand the risks or are not as able to hedge them?

Response: The sense in which I use the term, risk, is not intended to be technical. I am saying that in a regulated world, barring big surprises, customers pay whatever the cost turns out to be and in big surprises, investors may bear a share of that cost, including the cost of capital. We know that on average, markets price risk as though the marginal investor is risk-averse. And uncertainty over the ultimate rules affects the duration and the cost of the transition and chills investment.

Question: Why would total risk increase in a regulated system versus a competitive one?

Response: Regulation values simplicity and ease of administration and transparency, while competition values innovation, diversity and customization. When you finally reach competition, the market almost always surprises you. You can also find surprises in an investment environment where you make long-term

commitments. In that sense total risk could go up.

Question: Different products are offered to customers in markets where it makes sense to do so. Where it does not, customers stay on the fixed price offered by the utility. Are aggregate really increasing or are they just more transparent under a competitive model?

Response: My instinct says that in the aggregate, the risk goes up because I believe that price volatility will be greater over the long term in a competitive market. I am concerned that we will see the same kinds of swings in the electricity market that we see in natural gas and oil and it will make it much more difficult for industry or the rest of the economy to make investment decisions.

Response: Price volatility per se provides a self-regulation mechanism that allows new solution and mitigation tools to enter the markets. The problem is that there is a public good component in electricity. I believe there is some fear that this component will not be procured and it will create an outcome that is more severe than in the regulated environment.

Response: Unlike the oil industry, you cannot store electricity. The fact that oil is at \$50 a barrel right now has nothing to do with what is coming from the refineries and everything to do with the fear premium that the market has put on the price of oil. That fear is one of supply disruption.

Comment: In this new, riskier regulatory environment, will we be able to get a coal plant built?

Response: If the pricing that is in the market is correct, the next plant will be built.

Question: From 1940-1970, we added capacity at lower marginal costs every

time we built new plants. In the 1970s, each time we built capacity, we increased the marginal costs. The industry also embarked upon a disastrous technology – nuclear – that was touted to be safe, clean and cheap. There were also new groups coming to the political process and the net result was some bad decisions. So utilities stopped building capacity because the risk to them of not recovering from the ratepayer increased, and construction work in process was no longer allowed in the base in many jurisdictions. Today, we are awash in excess capacity, but once that is used up, will new capacity come on in time if it is left up to the market?

Response: The capacity will be built but it may be a lot of small, gas-fired peakers.

Comment: Minimizing, managing, allocating and identifying tradeoffs between different risks are at the core of the regulatory function. If you are an advocate of the traditional vertical system, you offer an idealized version of your preferred approach and a very flawed straw man of the competitive model and ignore things such as the absence of transparency in risk. If you advocate for the restructured model, you ignore things like depreciation, which is a valuable compensation for consumers taking on risk. Ironically, under either approach, the tools to manage risk look similar. The problem is that the transition is a very long one, and there is tremendous unpredictability. My observation is that because of the tremendous aversion to financial risk in the IPP sector – which needs long-term contracts – we are creating new regulatory mechanisms that in some instances are slow and bureaucratic. It may be necessary to provide investment certainty, but it is not something that restructuring's advocates initially had in mind.

Question: In the past, we may have enjoyed some of the benefits and being able to put off the costs. But as we moved

to a more restructured environment, some of the risks are moved up front. Given that the transition period and its risks are not going away and the lead time for a new plant is long, how will plants be built in the near term?

Response: Transition implies uncertainty. As long as you have uncertainty, you really cannot structure around risk. In my part of the country, the planners are not required to make immediate decisions because we are awash in excess capacity. Some day we will have to pay the piper.

Comment: In the regulated environment, the onus on every utility is to demonstrate to the regulator and the customers that it has acquired least-cost resources. The wise thing to do is to mix the portfolio. Even today's regulatory environment has a competitive element which is the regional structure for transmission.

Response: I agree that regional planning for transmission makes sense. The political challenge is how to make a

decision within the context of these regional forums.

Comment: I am also talking about regional scheduling and operations.

Comment: Fuel risk, environmental risk, load growth forecast risk all exist regardless of what regime we operate under. The real risk we are discussing is transition risk. The real question is whether markets allow people to better handle risk and do they ultimately lead to lower costs than in the old regulated regime.

Response: I think the industry itself is becoming more complicated independent of whether the environment is regulated or not. Philosophically, I agree that this is an incremental cost issue and private markets prove to be a much better tool.

Response: Is this good or bad? At least we are paying more attention and that is good, but it is a very hard problem.

Session Three. Back to the Future? Competition and Market Mitigation: A Judicious Mix or a Return to the Past?

Prices for electric generation were supposed to be market based. The prices would rise and fall consistent with supply and demand. Investors were supposed to be able to expect that prices and, therefore, revenues and profits would fluctuate accordingly, but would, absent specifically defined circumstances, be unconstrained by regulatory intervention. However, in light of experiences such as California, many are persuaded that the public will not tolerate high prices. The result feared is an asymmetrical situation where prices will be capped but floors will not be constructed to elevate price valleys. Distinctions between legitimate scarcity rents and abusive behavior will be lost in the political haze of accusations, investigations, and litigation. If prices are high because of distortions caused by poor market design, rather than scarcity or abuses, investors fear that they will be subject to price mitigation measures regardless of their behavior. Price mitigation measures could turn out to be similar to the rate of return scenario from which we were supposed to be departing. Illustrative of that trend, some argue, is the recent flurry of actual and proposed utility acquisitions of IPPs. Others point to the fact that consumers in New England are not being asked to cover the costs associated with the surplus of capacity that has contributed to generation bankruptcies in the region. As demand side bidding and hedge markets evolve and become more sophisticated and more widely used, prices will become more manageable and reduce the vulnerability of consumers to high prices for lengthy periods. Who is right in this debate? Can markets produce the symmetries and discipline required for adequate

investment and supply to consumers on a reliable, reasonably priced basis or will we have to rely on regulatory mechanisms to assure reasonable prices and adequate supply? If there are to be regulatory interventions or market mitigation measure undertaken, what should they be and what should trigger their use? Can the political pressure and temptation to intervene to moderate prices be avoided?

Speaker One

California's recent experience was anything but a success. It was not a failure of competition, but a warning of the importance of getting the market structure correct. The shortage of energy could not have been a problem had the right tools and structure been in place. Problems experienced included: market separation; frozen retail rates; requirements that IOUs participate 100% in the short-run market; and no LMP.

In San Diego, there are only two transmission corridors that can provide about 2500 MW of capacity for reliability purposes. Local generation consists of two plants that are forty years old on average. As you can imagine, the older generating plants receive significant subsidies to provide reliability and have no incentive to replace or modify their generation. It is difficult for a competitor to build new generation because of the subsidies those plants receive.

The state has entered contracts with providers and allocated them back to the utilities. It is difficult to introduce competition when a utility has several thousand megawatts of contracts and no one else can enter the market. We know that the energy markets are not pure. There is a lack of demand response and there are distorted price signals. People are using more energy. California imports a significant amount of its energy. Cheap hydropower coming in from the north makes it difficult to justify building new generation. If we do not fix our market structure, there will be shortages in the next few years.

One solution is to establish a capacity market, as is being done elsewhere in the country. The models studied suggest that California should establish reserves, create price caps for capacity and allow the ISO to secure capacity on a bilateral basis – projected or going-forward – to encourage that new capacity is brought into the market.

As a utility, we believe there are opportunities for us to provide for capacity in places where it makes sense and where there are opportunities for the markets to satisfy this.

Most important is the need to assure that iron goes into the ground. We must fix the market and remove the regulatory hurdles and we must move forward.

Speaker Two

I want to give you a sense of what FERC is doing regarding market mitigation. As we all know, there are no simple answers. Three things must be in place: adequate infrastructure; effective rules; and monitoring and enforcement. My area is primarily enforcement – both overseeing the rules and giving feedback to RTOs and FERC by trying to spread best practices as we go forward.

A big question is determining whether behavior is inappropriate. The obligations for all players are still being clarified. We are creating an analytic capability that can explain how markets and businesses work to help commissioners and regulators understand the processes. Today, there is still no standard model at the RTO/ISO level. In some cases, people work in

partnership to conduct market monitoring, while elsewhere, an internal group may have the lead and there is also an external contractor. MISO has only an external contractor, while California has both.

Our definition of market power is the ability of a firm to affect price and profit from it. The question is whether that is a strategic behavior or a decision that one is free to make. There is nothing like this in the natural gas markets, but the bottom line is that LDCs lock up their supplies for the winter. They are not in the market and do not care what the price is – they have their supply for their own customers.

Monopoly power of course happens on both sides and the remedies can be both structural in terms of requirements for divesting of some assets, or behavioral. FERC has used both tools and in settlements as well. On the benefit side, it is important to make sure that market power abuse is prevented. On the price side, I believe policymakers are compelled to intervene until there are meaningful demand side responses.

Each of the RTO markets uses mitigation. Each must determine if the mitigation should be applied to an offer as it is being made; to the entire market; or only to the load pockets. There has been some progress, for instance in the Midwest where in 1998, the price was over \$7,000 per MWh. Now there is iron in the ground in the Midwest. In New York City, however, mitigation appears to be extending the problem. There are also NIMBY problems there, so one cannot blame it all on mitigation.

FERC is also enhancing market functioning with its market-based rate screens, compiling rules of behavior and standards of conduct. The newly expanded audit staff has visited 80 companies to date and expects to work through another 300 before the end of 2004. There is also emphasis on restrictive transaction

reporting that has taken on a new level of importance following the Ninth Circuit Court's decision.

My hope is that mitigation is a transition measure until demand side responses are in place. We are trying to balance consumer and investor interests because that is our regulatory challenge. We may take more political heat when prices rise, but we hope to work through this without too much damage to either the customers or the investors.

Speaker Three

The past was a market driven by state-sanctioned monopolies. There was some emergence of tender-based competition, but the rules for those tenders were a bit odd. There were widespread, but not universal inefficiencies. There were some bad investment decisions, possibly because of the lack of capital market discipline. Perhaps the most damaging feature of the past was that regulators and policymakers found it easy to meddle with the operation and practice of the utility industry.

Can markets produce the symmetries and discipline required for adequate investment? The answer is yes, for the reason that there are examples that are working properly, such as Norway, the UK and in southeast Australia. Can it happen in the US and will market mitigation help?

If the end-use customer no longer must worry about price extremes because the regulator manages that risk, the incentives to hedge are reduced and investors do not know whether the regulator will change the rules in the future. This is known as asymmetric risk, which is when the investment risk tends to be capped on the upside but not on the downside. Such risks are extremely difficult for investors to manage. So

intervention, if done badly, can have significant detrimental effects on markets.

My view is that mitigation has three purposes and the one I worry most about is using mitigation as a transitional tool. I think that a 2-4 year period is the time dimension in which to examine issues like market power. Obviously, that is different from the time dimension of the spot market. In the absence of liquid contracts, it is inevitable that some customers will face uncomfortable price outcomes that they cannot manage. That inevitably triggers political and regulatory concern and incentives to intervene.

Mitigation becomes a transitional tool to protect those customers that have been unable to operate because of the efficacy or lack of efficacy, of the contract markets. The solution is to lock in transitional arrangements that one believes are best for these markets and over time, wind them down and intervene with caution.

The second purpose of mitigation is to manage real market power. There are some fundamental steps to take: recognize that prices do move over and under long-run equilibrium prices. If competitive power markets operate in a constant state of disequilibrium, note that even when they work properly, your market definition must encompass the period over which the investment or real responses can take place. Define the market properly by using the widely accepted antitrust market definition tools in terms of time, geography and product dimension before taking further steps to mitigate market power.

When convinced that there is a market power problem, mitigate the firms that have market power. Provide safe harbors. Recognize how contracts affect behavior in the market in which you operate.

The third purpose is local market power issues, about which we could speak for hours.

In the markets that I believe are working well, what is interesting is how they differ. Some use locational pricing. There is still no demand side pricing, but that has not stopped them from becoming effective. There is a noticeable reluctance for regulators to intervene, although that was not the case at the start. The markets have in common a unified system of regulation and a high degree of centralized control over ancillary services, transmission operation and transmission investment. All are blessed with good transitional models – I think Australia's is the best.

Can we do this in the US? It will require boldness by policymakers and regulators and today's environment is not good for boldness for obvious reasons. Next, there is a strong case for a back-to-basics transition, although I do not see any reason why we cannot impose a transition from this point. I am not a believer in bifurcating into core and non-core and regulated and non-regulated, but I believe that if the regulated part of the market is managed through transitional – or vesting contracts as they are called in other markets – it might give us the time, confidence and stability to move to wherever you want to be.

If you do this, do not use wholesale pass-through to serve deregulated customers because wholesale pass-through fully exposes small customers to price risk and that exposure most likely will cause regulatory or political concern. Ultimately, to get investment in these markets to operate properly, we must give confidence to investors that there will be no need for regulatory intervention to set or control prices.

Speaker Four

If you asked the CEOs of the nation's utilities if competition was a mistaken policy, I think the majority would say yes and probably a small majority of state regulators would say that retail competition was a mistake. I think that most utility CEOs and state regulators probably think that wholesale competition makes some sense but are resolutely fearful that FERC will determine the bounds between the two.

However, the reports of the demise of competition are greatly exaggerated. A few numbers will show that we really have little alternative but to continue the efforts to make competition work. From 1999-2003, wholesale trading almost tripled from two-and-a-half to nearly seven billion MWh. More than 40 percent of this nation's operating generation is in some way owned by non-local utilities. Some are unregulated affiliates. About 167 GW of new capacity has been built by entities other than utilities.

Switching rates for large customers in Illinois, Texas, New York and Massachusetts have at times approached 50 percent. It appears that large customers want competition or regulation when it is good for them and the inconsistency can be handled by simply replacing the representative on the scene. Things have evolved differently for small customers, of course because I think we failed to provide them with alternatives. Small customers want predictability and to be assured that there is at least some measure of future planning. Customer satisfaction or dissatisfaction is affected by the years of interaction between business and politics. We are trying to get the kind of regulation that brings to those customers who do not wish to switch a product that has the advantages they have traditionally wanted, as well as some of the benefits of a competitive wholesale market. Regulation can do things to make the benefits of a competitive wholesale market available to residential customers.

The Illinois Commerce Commission held a series of stakeholder meetings to review the ways to accomplish this. I believe that the state will move toward 3-5-year laddered auctions because of the desire to see the price signals reach further out. I think we begin to send the right signals to the marketplace if our RTOs have a good pricing mechanism. I am sure this is a more promising avenue for exploration than the older IRM models or leaving it up to Southern Company in the south.

However, one problem is the preferred technology and under what circumstances. It will not be nuclear until there is a greater solution to the waste disposal issue. It may be merchant coal or gas-fired capacity or before those, trying various load-management techniques. We should explore whether there are the means to auction or otherwise market baseload capacity.

I am bullish on wholesale competition and I think the efforts to make retail competition work are important. Both require significant elements of new regulation and the understanding that we are all working with three highly inconsistent models of what the utility business is in the United States. We are building a combination of the politically feasible and the economically optimum that will be a good parietal solution.

Discussion

Question: Could you characterize the political and regulatory mix in the places where progress is being made?

Response: In the UK and in Australia, reforms occurred because of concerns about the inefficiency of public enterprises. In the UK, there was a more specific concern that the investment costs in the electricity industry would have to appear on the public sector borrowing

requirement, and it was imperative to move utility investment of the PSBR. At the outset of reform, there was a decision to explicitly set up one regulator that was tailored to the requirements of the sector. It was also easy to deregulate assets when the government has control, as opposed to expropriating from existing shareholders. Finally, never deregulate a market just before prices increase.

Question: How can we balance capacity markets with any certainty if the problem is that they will be inherently uncertain because they depend on political will to maintain them?

Response: The question really is what to deliver that gives confidence to the politicians and allows them to step away from what has been an extremely controversial area of public policy in the last 5-7 years. The answer is straightforward: develop the industry in a way that sustains superior service, quality of supply and moderate prices consistent with the efficient operations of the industry. One way to do this is by locking in a price path for a time and gradually unwinding the lock-in.

Response: While we are all concerned about the kind of volatile politics that can disrupt even well-ordered regimes, remember that virtually all investment still occurs in a political environment with some measure of political uncertainty, even in relatively mature political economies like the US or the UK. As we experiment with these evolving markets, we must keep some institutions, like utilities, in place to fix things that go wrong because that is both a capability and a political obligation.

Response: I agree that there is a compact among the regulator, utility and the market. A lesson learned in California is that the state is not capable of negotiating power contracts. That is not to say that a commission will not look at a contract and

say it was prudent to enter into it. One approach is to show your cards to the regulators so they understand what makes sense for your customers going forward. It is our expectation that regulators will stand behind some of these decisions because we were open up front. We must make sure the decisions we make are prudent and that we can defend them.

Response: From a non-US perspective, my observation is that the regulator sees itself as being the buffer between pure politics and the market.

Question: What conditions are required in a wholesale market to support a bid process? Why is a 3-5-year timeframe most appropriate? Is it true for all contracts?

Response: Our consumer advocate wanted to slice it at five. We also think it is important to have some price signal starting to reach into the future. We recognize that there may be a new set of political instabilities.

Response: For renewables it is appropriate to look at 10-20 year contracts because there is a social content -- a green component -- behind them. There are different reasons for different lengths, depending on the resource. One reason is that it is difficult to finance something that has a shorter contract.

Comment: IRP clearly requires that we integrate transmission and generation investment. There could also be a set of contracts that would involve some rolling re-contracting but they would represent only a small part of your contracted load because you must be able to guarantee a customer base that is willing to pay for the contracts over a longer period. I think we must evolve to a world in which investors are happy to take on the risk of a large, fixed investment with a series of rolling contracts, like developers of large office buildings are happy to do.

Comment: In standard offer POLR auctions, the winning entities may or may not own physical assets.

Question: Are there are alternatives that might be transitional or structural short of a full-blown RTO that address some of the market power concerns?

Response: One issue is whether there is tighter scrutiny on the conditions of open access. Another is closer scrutiny on behavior with affiliates. Another issue is what happens if you remove market-based authority.

Response: Regularized wholesale auctions would minimize these issues.

Question: Why have we been unable to define market power for those markets that are working?

Response: First, what is the definition of the relevant market? Antitrust case law lays out the definitions of what constitutes market power, but when you intersect that with the engineering questions about how the power gets around and whether there are constraints into a market, it still can be fuzzy.

Comment: I want to clarify that market monitoring and mitigation plans are necessary in New York City because of the number of local load pockets. I believe that market mitigation plans will still be needed even when the market is more open and competitive because there is a public responsibility for those who have it to protect the public from unreasonable and unjust prices. How do you suggest we move to having real price electricity and real demand response in a two-sided market?

Response: California has several statewide programs for critical peak pricing and getting real-time pricing signals to customers. There are drops of 15-20

percent on demand response, which is significant.

Response: From a FERC perspective, the wholesale markets must be working so that the price signals can be passed on to the state and retail customers.

Response: I suggest holding large customers who have a record of shopping to it because you cannot get the demand response when you have people who come back on the regulated rate every time a cost goes up. Utilities ought to look for alliances with environmental groups on demand response mechanisms because load management has too often just been a cover for a subsidy when in fact it is an effective tool that has real value even with a reasonably efficient wholesale market.

Response: The key to demand side response is to show the price and then give your customers the ability to respond, for example, with interval metering. I think there is a role for appropriately targeted subsidies to make some of these ideas work and to scale them to the appropriate customer base.

Question: Capacity markets would reduce the investor's ability to earn scarcity rents from the energy market and would also distort the signals to end-users. Why do we need them?

Response: We need to encourage or provide the ability for new generation to enter the market and to finance that generation. I do not necessarily agree that the introduction of a capacity market in California will eliminate or completely hinder the ability to extract scarcity rents.

Response: It is politically impossible to remove caps on energy prices. Will regulators cap the capacity market if the system goes into distress? Do we have confidence that we will not mitigate our capacity markets?

Response: We are in an impure market structure. New entrants cannot just decide to come in, because it takes an extended period of licensing, permitting and getting past the NIMBY issues. You cannot just assume you can build a new transmission line or power plant. Some form of mitigation must exist to take care of some of the market impurities that will always be there.

Question: How do you do the right thing for the markets and meet the political test if you are an electricity regulator?

Response: The fundamental problem of FERC regulation over a dozen years has not come from its lack of a coherent objective or from any fault with it. But changes in the composition of FERC and shifting majorities have led to a stop-and-then-hurry-up set of policies. Too little is done where it clearly should be done and then there is an attempt to make up for that by something absolutely overwhelming, like SMD. It was more than the political base could support at the time. If market pricing authority is done with a slow sureness of purpose, one will find that the states that would go to war over SMD will not go to war to protect their local utilities' exercise of market pricing authority. The political dynamic will differ. We can do this but it requires patience, persistence and some moderation in pursuit of our bigger objectives.

Response: If some regions do not want to do it, maybe they can isolate themselves and maintain their low-cost situation, or maybe they will cross-subsidize their high-cost incremental supplies with their low-cost power and end up in a deeper hole. I think focusing on the places where the momentum is underway probably makes the most sense.

Comment: I have never thought that it is inappropriate for other regions to engage in experiments, primarily because they have much less to lose if their rates are

very high. I hope the ultimate metric is the reliability and the prices to the end-use customer over a long period. In the meantime, the traditional system does know how to get plants built. It is called "obligation to serve." The claim has been made that this has been very expensive with all the mistakes that the regulated system has made. But it has not been as expensive by orders of magnitude as the California crisis which hit the entire west, including my state, where retail rates are 50 percent higher. We are still swallowing the costs. Therefore, why not be more forgiving? If the end-use customer receives reasonably priced, reliable electricity, that's it, unless those states want to change.

Response: Using California as an example is not productive because it was such a flawed process.

Response: I agree that nobody would repeat California. Ultimately, the test is what system can adjust and make amends for the inevitable mistakes that either competition or regulation will make.

Response: If the way that you maintain one-third of your states with low prices is effectively by denying open access, that is something to think about quite carefully.