Harvard Electricity Policy Group
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RAPPORTEUR'S SUMMARY*

Session One. Overcoming Market Failures without Overturning Markets.

Electricity restructuring to rely more on market forces emphasizes the role of incentives in guiding innovation and investment decisions made by many market participants rather than a few central planners. Good market design can help align incentives with the physical reality to promote better investment choices and allocations of risk. But even the best available market theory cannot incorporate all the realities of the electricity system and industry structure. Combined with market design flaws and unintended consequences, there remain "market failures" that invite intervention by central authorities such as legislatures, regulators and related institutions that can impose and enforce mandates or socialize costs. Mandates for transmission expansion, installed capacity requirements, resource adequacy programs, market power mitigation and administrative operating reserve requirements are but a few examples. There is a threshold question of when such intervention is needed. And the interventions inevitably create tension with the broad objective of relying on market forces. This leads to a slippery slope argument. Will seemingly necessary and helpful interventions create a dynamic that ultimately defeats the broad objective? Is centralized intervention to support decentralized decisions an oxymoron? How can we address market failures by designing interventions that are limited? What are the characteristics of interventions that are more likely to be self-limiting? Can market interventions be structured so that we know when and how to stop? If so, how is this done in theory and in practice?

Speaker One

First, I offer the definitions of reliability and economic enhancements applicable to transmission. Reliability enhancements are those required to meet the standards that are in place. Economic enhancements are optional investments that reduce congestion, acquire new transmission service, interconnect new generation, increase transfer capability or in some cases acquire FTRs.

I believe bulk transmission reliability is a public good, but that economic transmission investments are not, because if they are not made, the only effect is higher prices for somebody. I believe reliability investments ought to be centralized in terms of planning and

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construction, and even pricing, but that economic transmission investments ought to be left to the market.

The arguments about who pays for transmission when centralized decisions are made may result in regulatory deadlock. Initially the benefits of investment will not go to investors or to those who pay for it in the case of regulated utilities, particularly if you socialize cost. If market failures result in someone else paying the costs, then there will be incentives to fail because those who would otherwise pay for transmission will simply wait until a market failure is declared and then someone else will pay. I think regulatory interference with economic investments more or less takes away merchant transmission opportunities.

If there is centralized decision-making, there will be no market test to determine if congestion should be relieved at all. Not all congestion is economic to relieve, but how would you know the difference? Distributed generation or other alternatives to transmission would probably be discouraged because a centralized decision-maker will favor transmission solutions.

There are a few common arguments against relying on the market to fund new transmission, such as awarding FTRs is insufficient because they become less valuable after investments. Another is that transmission investments benefit all customers – today and in the future. Still another is that projects may have overall benefits but the benefits to any one party will be insufficient to incent investment by another party. Or project may delay or negate the need for future reliability investment so therefore it should be socialized. And because transmission investment is lumpy, we should build and socialize the cost of a superhighway to save on generation costs.

I do not think that anyone will invest in transmission simply because of the value of the FTRs. They will invest because of the network's ability to become a deliverable resource for customers and to get lowered delivered-energy prices. If you are a generator, it is the ability to receive higher energy prices or simply to have new firm transmission services that are otherwise unavailable.

If a project is not required for reliability but has reliability benefits, we should ask if those benefits are needed by anyone. If the answer is yes, then the costs and benefits should be allocated to those who need the reliability improvements. In other words, it may be appropriate to socialize the cost. But if the answer is no, then other market participants should not be forced to pay for the line.

Should customers or other market participants be required to pay for benefits they do not need? Should generation? When projects have benefits overall but those for any one party are insufficient to incent investment, it is the perfect opportunity for merchants to assemble syndicates. I also think RTOs, RSCs and other planning entities can identify such projects and put together parties to fund them.

If an economic project delays or negates the need for a future reliability investment, you may want to socialize the cost and have centralized intervention. But what is socialized should be only the difference in cost between the new project and the previously planned reliability project. If an economic project speeds up or adds to the need for such a project, the funder should also pay for that.

If investment is lumpy, does that mean that someone else needs to subsidize the excess capacity being created, even if they do not benefit from it? If a project has long-term benefits, the entity funding it should receive long-term rights to the capacity.

The argument that we should build and socialize the cost of a transmission superhighway to save on generation costs is one of my pet peeves. Transmission is cheap only on an average embedded-cost basis. The cost of transmission associated with an incremental generation project can sometimes even outweigh the generation cost, particularly if the generator is located far from load. Wind generation is a good example of that.

Deciding what projects are reliable or economic must be non-discriminatory and probably made by an independent entity. If there are market failures, we need to look at why they occurred and correct the market, before building more transmission and socializing the cost. For example, it might be more cost-effective to build generation in a specific location. Markets must be designed correctly and participants must face the true costs of their decisions.

Utilities often serve numerous retail customers of other utilities directly off the transmission distribution wires so it is difficult and hugely expensive to meter in real time, catch leaning in real time, or to cut off some customers but not others on the same circuit. These are practical constraints, but other operational realities include calling for TLRs where they relieve system constraints. Other ancillary services are also problematic because they must be available not only when required but because they are location-specific. Loop flows also suggest that reliance on market solutions will be difficult.

If demand response can dampen some of the effect, are regulators willing to allow prices go high or to mandate RP deployment to get customers off the system? If prices do not get that high, who invests in peakers? Just leaving things to the market does not necessarily get you to fuel diversity.

Assuming there will be regulatory intervention, my solution is YMHR – “You Must Have Reserves.” By that I mean a planning reserve for each LSE in the system. Leave it to the LSEs to decide how they acquire their reserves. It could be through a voluntary market, bilateral contracts or building and owning generation. However, there must be flexibility.

Speaker Two

I think the permanent bureaucracy in the state of California is almost genetically predisposed to integrated resource planning (IRP). One of the weaknesses continuing to surround the discussion of market restructuring is a certain ambiguity about its purpose. Among politicians, the sole purpose for restructuring was to reduce prices. It did not and as a consequence, the political sector considered it a discredited concept. There is also a bit of an overly romantic view of markets, particularly among economists.

Much of the California experience started with the way we demonized markets. That was a fundamental reaction in the governmental sector to the meltdown. Locking in 10-12-year contracts by the state on behalf of the IOUs is perhaps one of the worst public sector decisions in this area in history. When the markets exploded, it was easy for the public and the politicians to understand that we were being cheated. But when things go wrong, I am not certain it is particularly helpful to focus exclusively and in an obsessive way on that.

Another factor that has pushed the state in the direction of central planning was the complete collapse of the merchant mode. No one will build without a long-term contract. As a consequence what we now call competitive markets is a utility procurement model.

I think that the fundamental job of state government in all areas is to assure the adequacy of public infrastructure. In electricity infrastructure is considered public be it investor- or publicly owned. If I am an elected official and my constituents are paying the bill for our electricity system every month, why should I not assert a certain dominion over how that revenue is expended? This may be the slipperiest slope of all.

In California, periodically environmental values trump a belief in economic optimization. It may not be universally true across the US, but I suspect there is more of this sentiment than the industry commonly accepts. I think that the public sector is justifying a certain amount of IRP on a portfolio theory that is premised on the notion that markets inadequately diversify fuel sources I suspect that adopting diversification as a paragon in the electricity world also works against an exclusive reliance on market forces.

Recently, the state's regulators have also received some positive feedback. AES announced its intention to build 500 MW of new capacity – the first time that has happened in a few years. The Franklin Utilities Fund, the best-performing utilities fund over the last five years, told *The New York Times* recently that California was its strongest market and that it was investing in both SoCalEd and PG&E because of the state's improved market climate. General Electric and Calpine have announced plans to invest more than $500 million in new, combined-cycle technology at a site in southern California. These things help reinforce the trend of the state's regulator process.

The market failures that are about to be corrected are: inadequate demand response; inadequate investments in energy efficiency; inadequate identification of environmental externalities; and possibly inadequate supply diversity, although it is open to question whether we will be overreacting to gas price volatility.

At the center of the push for IRP is the renewable portfolio standard, a relatively small component of the overall generation mix. Surveys in the last several years consistently show that 80-87 percent of Californians think the state should double its reliance on renewable resources. This creates a window to build and I suspect the central planners will jump on that as forcefully as they can. There is also a proactive approach to transmission permitting and investment. I believe we will run the risk of over-investment if we can get through the window of opportunity to build that the public has provided.

I think California will attempt to develop a capacity market because a real weakness in the political sector is an inability to distinguish between capacity and energy. I believe that a western-wide market for renewable energy certificates will be established so that the state is not held captive by in-state renewable generators.

We need to re-legitimize spot markets. I believe California's success in this will be based upon a successful build-out of the state's transmission system for many of the reasons attributed to the rationale for socializing transmission investments. The state should encourage self-generation among large customers and to provide an escape hatch for the mistakes that central planning inevitably will make. Finally, the principles of regulatory transparency and accountability – humility if you will – must be necessary elements.

Speaker Three

A completely bilateral electricity market does not work because the technology and the physics preclude it. The ongoing debate is about how to balance the commercial reliability and network interactions in order to achieve a successful market design. I understand the political argument that it would produce lower prices. But the real purpose is about the long-run investment incentives and innovation and in market participants spending their own money. To do this we have to confront the problem of coordination for competition. For a long time, we have talked about the character and design of the central institutions needed to have an impact on the market.

The first distinction I make is that when there is a central institution to coordinate activities, it does not make the critical decisions. The obvious example is straight energy purchases and sales in the spot markets. While we could imagine doing this in a completely decentralized, bilateral way, it will not actually work. And so there is an alternative where people provide voluntary bids and the system operator balances all of that and produces an outcome that is consistent with what the market would produce.

At another level, central procurement and its operating reserves are a good example, in terms of fast response and the public good, of becoming the operator and making the decisions about what to buy and where, then buying it and making you pay, through the mandate of the regulatory powers.

If you think that greater reliance on markets is good and investment decisions must be made, you want to design institutions that are compatible with this thinking. You could do this by defining products and services that are consistent with real operations. It is critically necessary to make sure that you do not create fictions that people then exploit in their own decentralized decisions.

If everything is a public good or nobody owns it, then you obviously do not think that markets will work very well. You need to establish consistent pricing mechanisms and design the central institutions to emulate efficient market operations and incentives. Target the structure and scope of central interventions to address market failures. Set principled limits for intervention based on the nature of the failures. And finally, keep the focus on the goal of workable, not perfect, markets.

There is a lot of demand for regulators to intervene in a variety of ways. Therefore, if they want to pursue the objectives of restructuring, they have to focus on market design and failures because it is better to fix a bad design than to micromanage the bad decisions that arise from a bad design. You should be worried about interventions that sow the seeds of other interventions. This is the slippery slope problem about intervening where needed, but knowing how to stop.

Market failures that lead to central coordination or procurement include network interactions and loop flows, contingency constraints and being able to respond quickly. These complicate the design of the markets, as well as the problems of market power. There are also unpriced products and services that are important for the system and lumpy decisions that have a material effect on the market.

The operational definition of market power in many settings is "when the market fails to do what the central planner wants." I consider that an extremely dangerous road to go down because the point of restructuring is that we were not comfortable that we actually knew. Therefore, we should be thinking about how to exploit the benefits of markets in order to substitute for that judgment whenever we can do it and it works well.

Our challenge is to think through the details because it is very easy to make individual incremental decisions which then lead to the need for others. Before you know it, you are back to the place from which you are trying to get away, because you forgot what you wanted to accomplish and created the problem anew. Think about how to go as far as you need to go with these interventions but also how to stop.

Speaker Four

I have chosen to focus on resource adequacy because it is one of the thorniest problems confronted while trying to design and operate competitive wholesale markets. In New England, there are arguments about requiring customers to pay for capacity. We know that competition in wholesale markets really can produce a generation capacity at efficient prices but that consumers are protected by regulators from very high prices.

For better or worse, it is assumed that the consumer and political forces that direct regulators cannot tolerate the prices we would see in true scarcity situations. However, price caps and rate designs distort true price signals and conceal any kind of looming scarcity. It also prevents any effective demand response. The constraints also limit the revenue that generators can anticipate receiving. The problem with New England's peaking units, as Ken Bekman of ConEd Energy has pointed out, is that they are only about a 7.5 percent capacity factor and must make their money in very few hours of the year if they are relying entirely on the energy market. Generators really do need incentives to build reserve capacity but such resources are capital-intensive with long lead times.

The surest solution to all of this is to get rid of price caps, change rate designs and have real-time pricing, but we all know it is unlikely that this perfect market will happen. If consumers are willing to pay a fair price for the reserves a central planner thinks are needed, what is that efficient price?

Some argue that generators can receive sufficient revenue from the energy market, as well as the revenues received form ancillary services, operating reserves and other products. Even with price caps, there is an argument that these should cover fixed and variable costs. It is true that energy prices ought to reflect a scarcity in capacity, but there is a real debate about whether capacity itself is a tradable commodity. What are we buying when we pay for capacity? Is an economic environment that is good for investors and others coming at the significant expense of customers?

Since deregulation, about 10,000 MW of capacity has been built in New England. The reserve margins are 25-30 percent depending on how you measure them and over what is needed to meet a one-day-in-ten, loss-of-load probability. However, ISO New England forecasts insufficient capacity as early as 2006, citing the worst case of demand and the possibility of significant attrition of older units. But older units have not been retiring and instead are hanging on tenaciously.

Capacity clearing prices over the last six years have ranged from zero in many months to a high of $5 per kWh a month. Some of that volatility is due to changing litigation over the deficiency charge imposed on generators by regulators. Also not surprisingly, there are very low prices for capacity in the supply auction.

ISO New England has proposed a market for capacity that would rely on an administrative demand curve with four zones where the curves are applied differently. It is more focused locationally and allows LSEs to hedge with bilateral contracts for capacity. An alternative proposal supported by many parties in the region argued for a single regional demand curve with generators making a minimum commitment to operate at least three years beyond the current capacity payment in order to receive it. The rules also should be aligned more closely with New York and eliminate the seams issues.

The ISO then improved upon its proposal. All capacity payments are reduced by infra-marginal revenues obtained from the energy and other markets. Market power mitigation measures are beefed up and there is more clarity about how capacity is transferred among the participants and more subdivision of the region into different zones.

Most important for the regulatory community, ISO indicated that at minimum capacity requirements when the loss-of-load probability is one-in-ten years, at that point generators are eligible to receive twice the cost of new entry – the cost of constructing a new, single-cycle generation unit, which is about $15.50 per kW month. From a regulator's point of view, when we achieve the level of one-year-in-ten, loss-of-load probability, would consumers want to continue to pay more to build more and more capacity? This is not an insignificant argument about cost because as we calculate it, the ISO proposal would result in a charge to New Englanders about once every seven years of an additional seven billion dollars for capacity that may be unnecessary.

Generalizing from this problem I conclude that you must try hard to specify the exact nature and size of the risks and examine all of the possible interventions to find the one that will be the least destructive. Then you must ask if that intervention can be made to work as the market would work. Can your intervention be halted or fade away as there is decreasing need for it? Regulators do not think the demand curve will go away once it is installed. Finally, can the disruption be offset over time by market changes? Depending on how you design it, you can gradually mitigate its impact through reduction, subtracting infra-marginal rents and the like.

Discussion

Question: Is the need for intervention partly driven by the lack of real prices? Would it be appropriate for transmission and generation decisions to be made on the basis of the resources consumers ask for and really need?

Response: There is resistance by regulators to show customers the real-time price. To a large extent especially for small customers, the rationale is that the system of averaging and price disguise is a form of social insurance and regulators ought to protect the individual customer from exposure as a way to make it better for the overall customer class. California exceeds 90 percent of peak about 7-12 hours a year. However, you could send a signal to retail customers based on the air-conditioning load because then you are trying to induce behavior that will not have what are considered socially unacceptable consequences.

Response: The resource inadequacy problem is a market distortion, not a market failure. Pricing structures are the distortions in that market that make it less than perfect and therefore give us an inefficient or inadequate level of capacity. Massachusetts regulators have reduced the default service price for large C&I customers from a two-year to a three-month product. But the political will to shift completely to real-time pricing for customers who could handle that does not yet exist. Retail customers who want to avoid the competitive market could and should have a real-time rate with all of the appropriate protections in place for low-income, the elderly and people at real physical risk. Ultimately, I believe we could get there. Better demand response would certainly mitigate the destruction of regulatory intervention.

Response: The textile, chemical and paper industries are a larger political problem because they cannot tolerate real-time prices.

Response: A pilot project in California found that non-profit customers have been the most responsive to real-time price signals.

Comment: No matter what you do to compensate for the reserve margin or whatever you mandate leaves no incentives for voluntary investment.

Response: Reserves are often used to mean different things. I make the distinction between operating reserves that are a problem caused principally by fast response needs and contingency constraints over short periods and administrative standards. The simultaneous calculation of reserve and energy prices and paying opportunity cost for the reserves based on what is happening with the energy prices are examples of things that can become consistent with reliability rules. To the extent that large commercial customers have real-time pricing, they can compete right on the margin.

Response: Groups like the Silicon Valley Manufacturers Group have proposed that the obligations be met through a tradable capacity tag that would pass much of the risk to suppliers but attempt to limit the degree of regulatory intervention.

Question: Do you begin with a market and then overlay central planning and then coordination to clean up anything that does not go quite right?

Response: I think that California is sufficiently headed down the slippery slope that it will be conducting interventions because of what it characterizes as market failures. This means that the markets do not do what the central planners want them to. In demand response I think that will be a near-term subject of intervention. There is no price signal and the day-ahead market was eviscerated. A disproportionate number of long-term contracts are locked in. I hope that as the recreated day-ahead markets and real-time markets grow and take on legitimacy, a real-time price signal will evolve for certain customers.

Question: Are you saying that your administratively determined peak ahead of time may or may not coordinate with the actual system peak that the ISO deals with?

Response: The critical peak price will be triggered by the ISO determination of which hours it should be charge in, but the price itself will have been set in advance by an administrative projection.

Comment: I think that it is integrated resource markets, not planning, that we want to use to get market forces in wherever we can.

Response: If the debate really were between a one-and-ten- and a one-in-twenty-year, loss-of-load probability, I do not think we would have a difficult time finding agreement. If we are trying to have interventions mimic what a market would do, would consumers be willing to spend that kind of money to avoid a blackout that basically would not occur anymore frequently than in the history of electricity itself? I think the real issue is about the reasonable level to expect of consumers.

Comment: A demand curve that is too high will stimulate demand response because people will ask to be curtailed or they will basically opt out.

Question: How do you define market and when do you know when it fails?

Response: The market is what you decide and it is complicated because of where you set its boundaries. There is a failure hierarchy such as California's experiences in 2000 and 2001; ISO New England's experience of excess capacity in the wrong places; and PJM's experiences in early June 1997. These failures of different types and intensities suggest that there is an underlying problem and we ought to fix it.

Comment: Maybe it is easier to ask how we know when the market is working.

Response: Are most of the investments being made by people who have their own money, or by using the mandatory authority and police powers of the state to compel others to pay?

Question: Can you compare and contrast "You Must Have Reserves" with the demand curve variations that carry a stupendous price tag?

Response: Administratively set curves for determining capacity payments are risk in terms of both price and whether the capacity really will be built given the time frames for building new generation, especially in densely populated places with limited sites. Set the reserve margin and let the LSEs figure out how to meet it. This is more like how a real market would operate than the demand curve, although I realize there is some debate about that.

Response: In a competitive retail environment, LSEs do not know who their customers will be some years out and so they are not in a position to take those risks. Have generators decide and take the risks.

Response: An LSE's capacity reserves can be tradable. In other words, if it loses a base of customers in any time period, it can sell that capacity.

Response: The mechanism would operate a little like a spot market. LSEs that see risk going forward will be in a position to hedge that risk if they want, but it will be their choice.

Comment: I think consumers can learn to understand and accept the limitations and advantages of market forces.

Comment: The willingness to expose consumers to high prices must go hand in hand with market design changes that give them the ability to react. Consumers are most tolerant when they have the ability to do something.

Question: How do we get new steel in the ground? With a three-year capacity market, do we create a situation that all new load or new demand will be met by peaking resources as opposed to a certain resource mix?

Response: I am skeptical that a capacity market will prove an effective mechanism to induce new investment. I think my state will rely on a procurement model where the planners say *x* amount of new capacity is needed and that the LSEs ought to conduct a competitive solicitation to provide it. That is a fairly blunt instrument and I do not think we have recognized the consequences of its bluntness and imprecision.

Response: I think the chances are that the New England model will over-produce capacity and put consumers in the position of paying too much rather than too little.

Question: Will base load or peaking capacity be over-built?

Response: We want market participants to make that decision. However, New England could use more peaking resources because it is running a lot of intermediate units too much to make up for a shortage of peakers.

Comment: The first part of my state's planning process begins with FERC. If a reliability criterion is not going to be met, the transmission owners have a legal obligation to step in and do a regulated solution which could be more transmission or other solutions. I am concerned whether the problem is with the market signals or with the economic incentives. We do have some merchant transmission.

Comment: From the standpoint of balance-sheet growth in the utilities' regulated businesses I prefer to see them add to their balance sheet with transmission investments. My state already has plenty of competitive generators that will invest in generation assets. I believe the primary tools state government have are its land-use authority and its power to license. Almost all of the economic regulation of the bulk transmission system was federalized some time ago. An example of a recent regulatory failure in California is the Valley Rainbow project that would link the San Diego system with the SoCalEd system but around 70 percent of the ratepayer benefits would flow to ratepayers outside the San Diego service territory. When your scope of benefits is so broad and so difficult to determine accurately, I think that is an argument for socializing that risk. That does not close the door on merchant transmission projects, but the TransElect project on Path 15 would not have succeeded were it not for the careful shepherding and quasi-sponsorship of the federal government.

Session Two. Active Markets and Reactive Policies: Requirements, Rules, Incentives and Business Models for Reactive Power.

Electricity market designs focus on real or active power, the megawatt flows bought and sold. Engineers understand the critical role of reactive power, the megaVARs produced and consumed. Watts and VARs are joint products that interact in a complex way. Although reactive power requirements can be the determining limit on transmission transfer constraints, most market model designs ignore active-reactive power interactions and assume that the required VARs will be there somehow. The somehow's have been a mix of good engineering principles without integration of market forces, rules and mandates and cost compensation. But as active power markets develop, the incentives may create a commercial dynamic that works against good engineering principles or limited cost recovery for reactive power. What models have worked and what problems loom? How should we structure incentives for investment in reactive power capability? What are the respective reactive power requirements from generators, transmission lines and reactive devices? Reactive power does not travel well: does this raise a problem of local market power greater than with active power? How do pricing and standards for loads interact with reactive power requirements? How do current rules and regulations interact with market designs and commercial incentives? Do we need reactive prices for real markets?

Speaker One

You cannot maintain voltage levels across the system without reactive power and if you have no voltage, you cannot transmit real power. I use the analogy of a wheel barrow to define reactive power. Its legs and picking it up are the provision of reactive power that enables you to then push forward and deliver the active power. Taking the analogy further, if you lift the wheel barrow too high and spill some of its load, you will be unable to deliver. If you drop the wheel barrow and cannot push it forward, you will have insufficient reactive power.

We need reactive power to facilitate the transfer of active power; maintain system reliability and support local system voltage. Reactive power throughout the 24-hour load cycle ebbs and flows so it must be managed in real-time in much the same way that control engineers forecast and balance supply and demand.

Generation can produce active power onto the transmission system through the distribution system to the load. The generator can drive voltage levels up and can also absorb reactive power and pull voltage levels down. Typically, large industrial load with induction motors will generally be consumers of reactive power and tend to drag down voltage levels, while commercial load with lots of fluorescent light like shopping malls, will tend to create reactive power and drive up voltage levels. The transmission and distribution systems, the lines and cables and some of the compensation devices, also produce and absorb reactive power. When talking about reactive markets, we often talk only about the generators.

A control engineer is not really thinking about dispatching reactive power; instead, he or she is thinking about managing the operating voltages of the system right down to the end-user. If the balance is wrong and the system voltage is too high, you could exceed design limitations or flashovers and uncontrollable shut-down of your system. Conversely, letting voltages drop too low triggers instability problems with motors tripping and stalling. If some of those motors are inside power stations, you could lose the stations themselves.

Reactive power does not travel well across a typical transmission and distribution system so you need to develop a voltage profile that shows the voltage gradients. You need to withstand contingencies, such as when the loss of a line and thus, its capacitive effect, increases the load on other lines which then try to drag down voltage levels. Increased reactive power must come from somewhere in order for the system to remain stable and its voltage levels constant. So it is important not only to maintain your voltage levels throughout your 24-hour load cycle but also to have reserve capability to manage for unexpected contingency outages.

The UK began to pay attention to reactive power in 1990 when the market was introduced. It considered zonal payments associated with reactive delivery, nodal pricing and eventually arrived at the solution in use today.

This solution consists of an obligatory reactive power service – which is a default service – and an enhanced reactive power service. Both services interact with transmission investment. The government is the regulator. It is funded with straight prorated payments from the suppliers. Large generators are obligated to have a capability to deliver an ability to absorb and to produce dynamic reactive power. The default payment is about $2.40 per megaVAR hour.

People do not have to tender but if they do it is through a tender process that runs by auction twice a year in October and April. It also allows for non-generating sources to enter the market if necessary and gives them the option to contract for capacity, back to capacity payments. The generator can create its own incentives and if we do not like the offers being made, it can revert to the default payment.

The process is transparent. The assessment for the successful tenders is published on the Web site where anyone can view them. About 37 percent of the contracted generators are using the market arrangement, but that actually represents about 45 percent of all the lagging capabilities. We probably receive 60 percent of all the lagging reactive requirements from those contracted generators.

The generators can price their megaVARs to make them attractive for the system operator to use. They have the ability to offer excess over and above the obligatory bids.

New England introduced payment on a capacity basis in 2001 which is paid to qualified generators – those making a measurable contribution of voltage support as defined by NEPOOL's reliability committee. So it is based only on their lagging capability. The price is $1.05 per kiloVAR a year. There is also a rider about overpaying and capping if need be and a lost opportunity payment.

In New York, if you are receiving capacity payments in the active power market, you also then receive some reactive payments linked to your capability. You have to prove this. If you do not deliver what you say, payments are withheld. Similar to New England, there compensation for pull-back against the locational prices and payments for the transmission components are recovered through the rate.

From an operator's perspective, these simple arrangements do seem to meet the needs of the operator. I question whether more complex arrangements are needed to achieve the same end. In the UK there has been some deferral of transmission compensation equipment installation on the back of slightly improved capabilities where they are beginning to be introduced. There has been debate about widening the scope of the market to include some of these transmission devices, but there is no particular appetite to make that happen right now.

Speaker Two

FERC has been studying reactive power pricing for several months. A few of the conclusions to date are that there are many inconsistencies and many informal rules of thumb. FERC Order 888 announced different ways to price it. For example, the generator connection rule established that generators should not be compensated for producing reactive power within an established range but should be compensated in an emergency. FERC imposes penalties on ISOs if they fail to produce reactive power.

The issue is how to design an efficient market with minimal intervention. If generators are compensated, how is that done? Zonal and locational pricing are debatable; should generators receive comparable compensation? Many old-timers have told FERC it is good utility practice not to compensate. The generators that exist inside vertically integrated utilities have been compensated all along, but the argument is that IPPs should not.

Capacity markets can be straight, cost-based payments like the Opinion 440 AEP payments. There can be a co-optimized locational ICAP market or spot market pricing options, although we do not have the software yet. One approach to market power is cost-of-service mitigation which many do not find attractive.

Today, some of the generation of reactive power is mobile; it can be put in place for several months or moved elsewhere if the market does not demand it. American Superconductor installed a device in Connecticut that paid for itself in a few months.

It is not only reactive power dispatch that can allow you to move significant amounts of real power. By allowing a generator in an expensive load pocket to back off its real power and produce reactive power, improvements in the market could range from 20-25 percent.

Speaker Three

Reactive power is truly a matter if physics. As you put current through wire, there are reactive power losses. For high-voltage transmission lines, these losses are 10-20 times the real power losses. The orders of magnitude are reversed for a distribution system.

I think good operations starts with good planning. A transmission system needs a mixture. You want a certain amount of dynamic resources because you must respond to instantaneous changes in the system, but dynamic is more expensive than static. You want to be able to locate reactive resources where they are needed on the system because reactive power does not move well and there are high losses. You also want both conductive and capacitive control. If Memorial Day falls on a Monday, you will likely find that the voltages are quite high because many switched capacitors are used on the distribution system. When the timers click in on Mondays but there is no load on the holiday, the voltage goes up so you want devices that will lower it. Occasionally, you may have to switch lines of service.

When planning your system 99.99 percent of the time you are within a range of normality, so the fact that capacitors drop off by the square of the voltage is not a big deal. But if there is an emergency you need generators because their reactive output holds. Static VAR systems are capacitors and inductors with a continuously acting, solid-state switching device. They are more expensive than static capacitors but more flexible in location and with much lower forced outage rates than generators. When a generator loses active power, it also loses reactive power. That was the first thing that happened in the August 2003 blackout when Eastlake tripped up on Lake Erie.

When voltage is low, there is usually time to act, utilizing various reactive resources or manual load-shedding. However, you may not have time to react in another phenomenon. Voltage collapse is when voltage drops and more current is drawn. The more current drawn, the greater are the reactive losses. In the US, industry does not have much under-voltage load-shedding. From a mathematical perspective, when you plan your system you can keep adding capacitors to bring up your voltage, but you need to plan for the contingency that occurs without warning.

I believe three principles are needed to harmonize the market for existing and new generation and transmission. First is comparability. There should be no difference based on ownership; a generator provides real and reactive power, regardless of who owns it. Two, payments should be performance-based; customers should pay for services that are or can be provided, and not for hypothetical services. Third are rational, not punitive, performance standards. It is all very well that a manufacturer says you have a 0.85 power factor machine, but if you cannot operate it at that, it does you no good.

Discussion

Question: Utility systems have dramatically different views on reactive planning, ranging from having adjacent systems with the same design relatively but sometimes dispatching to different voltage levels and profiles to utilities that attempt to supply as much reactive power as possible, even under normal conditions, form dynamic sources like generators. Do these differences in planning criteria affect compensation policies?

Response: It is difficult to solve all the problems at once. At this point, I think we are trying to resolve fairness to the generator and the load. Maybe the more important question to ask is why there are no national standards for reactive power planning. There are very few regional standards as we learned after the August 2003 blackout. We have also learned that relying on generators to provide most of the reactive power during steady states is a very hazardous solution under emergency conditions, even if it may be a least-cost solution under normal conditions.

Response: I agree that voltage management strategy is all about keeping the reactive reserves on the generators for the contingencies.

Response: Yes, we want that capability but when it comes to real-time, we lack the software to co-optimize and so we run the system with rules of thumb.

Question: If it is feasible to use reactive power to boost the system, does that challenge the reserve situation when a contingency arises?

Response: Whenever you dispatch reactive power that you have in reserve, you cannot re-use it. But if you do not need it, you should be able to use it to minimize system cost. I do not recommend digging into your reactive power reserve in order to get a little bit of performance and to threaten the reliability of the system and perhaps cause a voltage collapse.

Comment: I wonder whether the entire reactive issue needs to be further subdivided. In that case, it would seem that the compensation for generator contribution becomes more easily bounded.

Response: The generator can consume or produce reactive power, and the transmission system can do the same although it does not have as much control over it. But there are other devices that control how much you consume or produce and the same is true for load.

Comment: There may be merchant transmission opportunities to increase transfer capability to the benefit.

Response: Voltage drop is not an everyday occurrence, but if you are not planning for it, you have not done an adequate job. Your system can operate at *n* minus one, but it also has to be able to go through an extreme disturbance without a cascading event. Your relays must be set right. In August 2003, it was also the relays, not just the trees.

Comment: I do not disagree that you should compensate for reactive power, but I do not think it is as big a problem or worthy of quite as much compensation as the generating community might want us to believe.

Response: It is probably worth it study the economics of whether there is some benefit in correcting at the lower voltage levels where you might use cheaper devices than paying for more expensive ones at the transmission level. In the UK, the obligation is to deliver lagging power factor at 0.85 and leading at 0.95. I do not know if that is a standard machine design.

Response: In India, where the grid operator lacked the capability to establish the requirements for the state distribution companies, it put a charge on VARs and the voltage problems went away.

Comment: I think there is a good case to be made that distribution customers should be compensated and the compensation should be built into ISO programs.

Response: If the disco is taking power off the transmission system and taking a lot of reactive power and it is costing you to produce that reactive power, then the disco pays for it. If the disco is putting in reactive power and creating value to the system, you pay for it. I would not label the market participant that supplies either reactive power or reactive power capability. I would look at the quality of the capability and its value to the system. As for end-users, we simply charge the take-off at the distribution level and let the states decide how to re-price it as it goes through the chain.

Response: One VAR at the load is worth three at the generator. But first you start by asking what the standards are for a disco. Rather than socializing the full costs, you can say that if someone is below the standards that they must pay, or you are above the standards and are providing benefit by taking reactive loading off the system then you should be paid for it. But make sure those capacitors go off on the Monday holiday.

Comment: Baldick and Kahn wrote a paper that says there is relatively inexpensive technology available that can be installed so you do not get into scarcity situations. If so, it is even more important to price it in the context of the market. I do not know how often the situations occur and how large their impact. There may be hidden costs in reactive power pricing information because we have not produced calculations in a real system. I suspect that if we price reactive power, it will be quite volatile and you may need reactive power FTRs. But putting those hedging instruments in place will be difficult because of the large role played by losses.

Question: Reactive power compensation can be controversial, depending on the region. Is the real issue the cost or rate freezes that utilities are under in the sense that when an IPP enters a control area and files for its reactive tariff, there is a trapped cost for the utility in a rate freeze and no mechanism by which to receive the compensation?

Response: Yes. Every utility under a de facto or de jure rate freeze must worry about trapped costs. But the answer is also no because once the utility is off the rate freeze, the customers will be paying. Your opposition will now come from state regulators, rather than from utilities.

Comment: Cost allocation is not a very good way to pay people for what they are actually providing to the system.

Question: To what extent is the urgency of market solutions to reactive issues or to voltage-limited transmission lines a function of how large the reactive issue is?

Response: I think it is because of the amount of generation that has come in and asked for a piece of the pie, which at this point is a limited amount of pie.

Response: It is not an issue of whether there is a competitive market or whether we are de facto doing some kind of cost-of-service allocation. The issue is whether we can design markets that improve upon the status quo. Publishing prices is probably a good idea but I have never seen a reactive power reserve number anywhere.

Response: I do not think you have to introduce really complex arrangements.

Question: What is the difference between what transmission owners and generators receive?

Response: I do not use labels. Some entities supply reactive power at a given bus, while others take it off and there's a value. You do the same set of calculations as if it were real power. I would like to see a situation in which transmission owners are more active and can bid in capabilities. But that requires a new generation of software and new thinking about the markets.

Response: There is a lot of reactive capability out there. What concerns me most is that if we have another extreme disturbance that is blamed on reactive power, we will hear that it is the result of competition and the fault of the IPPs that did not provide reactive power when they were told. History tells us we will face an extreme disturbance somewhere, no matter how many trees are cut down. We compensate transmission elements based on invested costs that are subject to, in theory, both prudence and reasonableness reviews. Is this the best way to make sure the infrastructure is in place? I do not know.

Response: I advocate keeping any reactive arrangements at the reflected cost-based end rather than driving to complex market solutions. From an operational view, payments to generators are good because they encourage delivery and that gives you a little more certainty. I think resolving voltage-constrained transmission transfer capability is an active market issue.

Comment: We usually think of steady-state, real power as having a relatively high price and the reserves, however we denominate them, having a lower price, at least on average. I think it is likely that the reactive reserve prices will be the high prices and the steady-state reactive power prices will be the lower. Doing reserves in a reactive power context is more difficult than doing real power because the contingency cases inherently will be far more non-linear because they consider voltage effects. So from an implementation perspective, it is likely to be more challenging but that is not to say that we cannot do this.

Session Three. Retail Competition in Texas Electricity Markets: Is It Working? How Can We Tell?

Discussion around the country about retail competition in electricity often portrays Texas as a retail access success story. Is this an accurate portrayal of the situation in Texas? How does the Texas market work and what policies and practices have been put in place to promote competition? Have they succeeded or failed to succeed? Why? Is the headroom provided for in the rules sufficient for competitors to gain entry, or is it so high that customers are paying prices higher than they should have to bear? Who has benefited and who has not? What, if anything, has happened to service quality? How many competitors are in the market? Are new products and services being offered that were not previously available? If so, what are they? Are competing suppliers limiting themselves to "cream skimming," or have the benefits of competition been spread evenly across customer classes? How has metering been handled? Is energy efficiency being improved? How has "green energy" fared in the market? Have there been instances of abusive or misleading consumer practices? If so, what have they been and how have they been dealt with? What are the appropriate measures by which to evaluate the success or failure of the retail competition regime in Texas? What lessons should we learn from the Texas experience that might travel well?

Speaker One

ERCOT, the Electric Reliability Council of Texas, has many positive lessons to offer regarding retail competition. Competitive suppliers are successfully expanding their offerings of retail products and services. The price-to-beat (PTB) rates offer price protection for small, non-switching customers, as well as providing the headroom for retail electric providers to gain customers and adjust their retail prices based on the changes in wholesale prices. These rates are generally six percent less than the January 1, 1999, rates, adjusted for fuel-cost increases.

Since January 2002, the average lowest competitive offer has remained well below the average PTB. The PTB goes away January 1, 2007. A note of clarification: Texas may be the only state where gas and electric jurisdiction is split among the utility commissions.

From 2002-2004 the number of REPs has increased from 35 to 48 and product offerings from 39 to 59. With the exception of July 2002, C&I and residential switching has trended upward steadily throughout the state. The state's Public Utility Commission provides educational materials in print and electronic versions that allow potential switchers to compare rates and product offerings. While large C&I customers have reached almost 70% in switching, small commercial and residential customer-switching percentages are at about 50% and 20% respectively.

With the exception of a few periods, total customer complaints received at the commission have dropped steadily and are far fewer than complaints about telecom. Broken down by category, the complaint percentages are: metering, submetering and billing: 56%; slam and cram: 10%; provision of service: 12%; quality of service: 3%; electric solicitation: 0%; non-jurisdictional: 1% and discontinuance: 18%.

Our experiences with market implementation and the lessons we have learned and continue to learn in this state bode well for the future of both wholesale and retail competition on a national level. We are also pleased that the market and ERCOT are able to encourage green products that are related to the expanding wind generation within Texas.

Speaker Two

When thinking about the framework for success, we must consider the different definitions, evaluate them and measure the success against retail programs in other states. For example, defining success depends on the problem; low prices, not just high ones, can also be a problem. Competitive energy markets are based on the principle of freedom of choice, not coercion and monopoly. I believe today's consumers want what I term flowing content services for their homes and businesses that are consistent with their lifestyles.

Some possible definitions of success include: economic efficiency; well-designed and well-operated market structures and markets; customers who are served by competitive suppliers; and national standardization – no state is an island. Competition's advocates have argued that lower prices are the goal, but if such prices do not result in improved efficiency and do not maximize consumer welfare, we must re-visit our definition of success. It appears to me that many states define success as based on ratepayers' ability to buy from a supplier other than the traditional utility and success is measured by the percentage of switchers. However, remaining with the traditional utility is also a choice. And if customers are not clamoring for choice, why impose it on them? History has demonstrated that many innovations have created customer demand instead of responding to it.

Another way to define successful electricity markets is to compare them to other networked industries, such as natural gas, telecom and even cable, movie theatres and airports. This may prove helpful in evaluating policy decisions, but it is not the right test of success in the final analysis.

My own definition says that retail choice is exercised for all customers; marketers are not affiliated with network providers; the market structure mirrors those of other competitive markets; national standards for energy networks include discos; and flowing content integration both revolutionizes the product and the service models.

Progress can be measured by the policies that are necessary conditions for success. The Retail Energy Deregulation Index Advisory Committee has examined the US, Canada, Australia, New Zealand and the UK, using 22 attributes such as deregulation plan; percent of eligible customers; percent of switching; default provider rates and so on. The RED Index Score in 2003 ranked Texas 69; the state's world ranking in 2003 was third – behind the UK and New Zealand and ahead of every other US state.

My personal candidate for success is the gas model in Georgia where the switching rate was more than 80% and there were more than twenty marketers. Although the first two years of implementation were quite difficult, billing complaints have dropped significantly. The state's consumers understand that their retail prices reflect wholesale gas prices.

Texas – and ERCOT -- has learned much from its competitive market efforts. However, several problems have not been resolved to date. The mass market is still very concentrated and not all customers have meaningful access. In addition, there is little opportunity for flowing content integration.

Speaker Three

My measures of success for retail competition are: lower prices; high-quality customer service; many choices; and a high switching rate. Our organization is consumer-based and it from that perspective that I offer my observations.

Since deregulation, several things have changed the customer-utility relationship. Now there are contract call centers with customer registration systems. In some cases information is friendly only to Internet users. Customer protection rules have been amended. The System Benefit Fund has been raided by the Texas legislature.

Renewable power is a premium product that is only offered by a few providers. We were hoping to see some energy efficiency emerging in the retail sector but we are not seeing them advertised in this market.

Credit scoring is the chief tool being used to qualify customers for service. In the past, the affiliated REP and the POLR were required to allow a customer to pay a security deposit in order to establish credit. However, since the REPs can establish their own credit rules, companies with the lowest prices are in fact operating in a manner that locks people out of the market. We have seen numbers where 30 percent of Texas households are at 200 percent of the poverty level or less. We were also trying to avoid prepaid service providers entering the market with high prices but it is happening anyhow.

I believe people are not switching because the do not recognize the names of the providers that are listed with the commission. I think many people tend to stay with a provider they know and have been with for a long time.

The system benefit fund (SBE) is the biggest scandal at the moment. The legislation contained a fund that is funded by a 65 cents per MWh fee and the purpose is to the continue low-income weatherization programs in effect under regulation and to provide a 10-20 percent rate discount for low-income customers to make sure that they benefited from lower market rates. SBE also funds customer education and some budget supplements to the commission and the state's Office of Public Utility Counsel. In 2002 the rate discount was 17 percent and almost $11 million yearly went into the low-income weatherization program.

But in 2003 Texas had a budget crisis and the state legislature transferred $185 million of the $407 million available in the SBE to general revenue. It zeroed out the weatherization budget and the rate discount decreased to 10 percent.

In 2004 the commission amended the eligibility requirements and 350,000 out of 780,000 households were dropped from the program. We remain unconvinced that those 350,000 were really supposed to be dropped.

Deregulation is expensive for consumers. There are transition charges and even some late fees in some areas. ERCOT's administrative fee which started at 22 cents is now up to 44 cents, with predictions that it could climb to 70 cents within the next 5-6 years. Other expenses are the cost of the rate discount, transmission upgrades and congestion management costs and market monitoring costs.

Customers are confused by the price-to-beat and the electricity fact labels on their bills. It is difficult to compare the terms of service agreements.

Many improvements are needed to make the market work. We have proposals to improve the situation.

Speaker Four

Retail competition is working for my company and the competition for customers is fierce throughout the state. We have been in Texas since 1998. We currently have 2500 MW of load in the state. We serve 12,000 MW of peak load in North America and have customers in sixteen states and two Canadian provinces. We are able to compare and contrast the different markets in which we operate.

Is Texas the best? It has flaws and could be improved but it is the best market from a structural standpoint. We provide customers with creative, innovative products at competitive prices and extraordinary service. We have to do this and our customers expect it; otherwise they will choose someone else. The level of service demanded by our customer base is increasing. Customers with multiple locations want the ability to compare and contract their facilities.

Technology is in its infancy and metering has not caught up from either a price or technology standpoint to be that compelling yet. But I think that will change over time.

At first, customers want to be guaranteed that they are saving money. After awhile, most migrate to a fixed price because they want to mitigate risk. Now, some large customers are looking for more complicated derivative-type products to manage their risk.

We are in a for-profit business. We cannot serve customers who will not pay. Credit is a big issue for us and there are a lot of large companies with lousy credit with whom we must deal. We try to figure out the ways to serve them, whether through deposits or prepays, but we have to have a level of confidence that we will be paid.

My appropriate measures of success include switching rates, improvements in service and broader product offerings. One true indicator is that if consumers can go to market and have multiple suppliers competing for their business that has applications for price, service and everything else important to competitors and end-users.

Discussion

Question: In Texas a severe price spike occurred on February 25, 2003. The market worked and the power price went all the way to the balancing energy price in the ERCOT ISO. One of the new market entrants, Texas Commercial Energy, fell apart because it had already sold its forward contracts with its end-users and had not bought or hedged that power. After that, credit was more effectively managed. The consequence of the market working is that some of our competitors cannot survive. We worry about selling them power because we worry about their longevity. Is it good or bad if some competitors go away?

Response: It is absolutely essential that good ones prosper and bad ones are eliminated. That is part of the excitement of the market.

Response: How many REPS does it take to make a market? In my opinion we will see consolidation as well as some firms exiting. A company better capitalized than TCE might not have had that particular problem.

Response: Part of the accountability of being in business is accepting the failure of bad decisions or a bad business plan. I think regulators and ERCOT need to take a hard look at the credit requirements of participants so that success and failure is based on how well you perform from a customer standpoint, not from rolling the dice or gaming.

Response: I wish there was as much discussion about resolving customer disconnects as about resolving the problems of market participants.

Question: What is optimal for reasonable entry requirements without precluding competition?

Response: Our credit requirements are intended to protect the transmission and distribution service providers. We have not really regulated the credit requirements for buying power. ERCOT has its own credit requirements.

Comment: The nature of this industry in terms of retailers buying power from wholesale suppliers will always put greater credit requirements than regulators ever would.

Response: I am not sure that we have a system that gives us the assurance that the providers coming into the market are in fact prepared to follow the customer protection rules and provide service in the way the rules intended.

Response: The regulators do look at the technical capability of the entrants and ask them to provide information about what they have done in the past. But I agree that there has been a philosophy of setting a low barrier so that it is easy to get into this market.

Question: Are marketers serving residential and small commercial and those serving large commercial and wholesale markets treated equally?

Response: They are all treated much the same. I think that serving the mass market is a high-cost operation and the cost of doing business in that market will be effective in keeping a lot of people out.

Question: Would Texas regulators waive any entry barriers for marketers if they promised not to serve the residential market?

Response: There is a rule that allows a REP to serve essentially its own needs and that is the only instance in which some of the requirements are waived. I also think there is the prospect for doing mischief for C&I customers.

Question: If the PTB is coming off, if the amount of money going to serve or assist low-income customers is going down and if competitive suppliers are not interested in serving them, do you see a political issue looming here?

Response: The PTB goes away in 2007 even if 40 percent of the customers do not leave the system. It is a serious problem because the only available alternative for customers who do not want to choose is POLR. POLR has been controversial in Texas since the market opened. The end result is that it became so politically unpalatable to send people who could not pay their bills to a provider who charged more than anyone else that the commissioners changed the rules. Now the affiliated REP and the PTB become the POLR for people with payment problems. Once the PTB goes away, I believe that the only REP required to follow the standard credit requirements is the POLR. This problem is now being discussed. Personally, I would like to see PTB go away as soon as possible because it sets an arbitrarily high number and distorts competition.

Response: Should we treat energy poverty the same way we treat every other kind of poverty? As a compassionate conservative, I believe strongly that the place to take care of people's basic needs is with the welfare function of the state, not by asking state commissioners who are worried about monopoly problems to figure out the efficient tax collection modality for taking care of poor people. I do not like the way Texas implemented its program with a monopoly assignment. It took 100 percent of the residential customers and gave them for free to an affiliate of the disco and then gave them five years or whatever, to meet the 40 percent requirement and then they will deregulate. There will be too much concentration in the REPs and then passive customers may be abused.

Comment: It may be theoretically correct and more efficient to do it through the state treasury but politically, that is not an available option. The question is who administers the public benefits fund because we have heard what the Texas legislature has done. Other states do it differently.

Response: The demand for power is not growing because poor people are using more electricity. Demand is growing because of new housing subdivisions, water treatment facilities and other things that local governments want to attract new business and industry. As the cost increases, we must make sure we are still providing affordable service to everyone on the system because it is a necessity. The legislature set up the fund so that it was supposed to be outside the legislature in the same way the telephone universal service fund is designed.

Comment: Our company found out that when we create a customer complaint for poor service, it is seven times more likely that the customer will switch from us. It would be poor business practice not to try to mitigate that as much as possible. We have customer performance targets for 15-second average speed to answer which is better in comparison to most other utilities but not yet to the financial service industry to which we want to be compared as best in the nation. I think there it is appropriate for commissioners to ensure that rules are followed. What do you think about the fact that competitors must be allowed to pass through cost increases?

Response: I think less than half of the kWh sold in Texas are generated by natural gas; the rest are coal and nuclear. Although the capacity numbers look like natural gas is the dominant fuel, it is not in terms of the amount of energy saved. We do not like the idea that an increase in a fuel price that is responsible for 40 percent of the energy generated in this state is applied to 100 percent of all the kWh that are funded through the fuel factor. We think there are things that cause the PTB to be inflated because of the fuel factor increases. One of my concerns is the lack of good enforcement in the state for customer complaint violations. We favor more market-oriented solutions such as a compensation payment to a customer if a company makes a billing mistake. We have been asking for ratings of customers' service records and the number of complaints processed annually by the regulators but industry has never agreed to make that information available on a comparable basis for customers who are looking for a provider. Until it is out in the open, I do not see how industries can compete with each other on the basis of service.

Response: A public utility commission should not be the vehicle through which people complain. I want the state to treat all complaints for competitive commodities in the same way. I do not want energy commodities singled out as deserving of different treatment for purposes of consumer protection.

Response: I think you need more consumer protection mechanisms for residential consumers than for business. On the issue of higher natural gas prices, I agree that natural gas that is almost always on the margin drives the prices in Texas and the price of electricity correlates to that.

Response: The Texas commission takes enforcement seriously. By the end of 2004, it will have investigated 9,000 complaints and refunded approximately one million dollars.

Comment: The PUC's role in monitoring customer complaints should focus on fraud and major issues.

Comment: Have the administrative part of the PTB go away by holding a competition for the companies who will supply the tranche of people who do not want to switch.

Comment: In New Jersey, the risk of non-payment from customers is with the wire company, not the suppliers of basic generation.

Response: I oppose the New Jersey model for retail. I want to be able to buy a whole set of services that are critical to my need for efficiency, productivity, comfort and convenience in my home or business.

Comment: A wholesale market auction for residential is a viable alternative for customers who are very difficult to acquire on a one-by-one basis and really need some type of aggregation.

Response: We often ignore benefits that have accrued to consumers from industrial and retail customers having lower prices. I am not sure that the growth in switching in the residential market is not some sort of exponential curve. And from a policy perspective, do we want to be paternalistic or do we let people make intelligent decisions?

Comment: I think the New Jersey model is perpetual; once you start those auctions, you probably have to hold them forever because of the number of people who do not move. The Texas model is built on the idea that the PTB is a transition that over time goes away and that customers are educated. Look at grocery stores. People understand that they have the right to go to whatever store they want for their electricity. They are educated enough that they can do this and there is no longer a need for a government-operated auction.

Question: How does Texas implement the renewable portfolio standard (RPS)?

Response: How much you retire each year depends on the size of your load.

Question: What are the advantages of nodal versus zonal for the retail side?

Response: My concern is that I do not know my congestion costs when I procure supply in a zone and it moves to a node. Once I know the rules, it will remove the uncertainty.

Response: Larger customers tend to prefer zonal. Typically, they tend to be located in more congested areas so the more nodal it goes, the more they pay.

Question: Have there been many changes in metering since there are now more competitive suppliers? Do the meters reflect accurate price signals, demand response and energy efficiency?

Response: Only a few markets have the ability to install revenue grade and interval metering. Most of our customers want a fixed-price produce because they prefer certainty. We negotiate a curtailment product or service for the customers who can mange their load. I think that works better than institutional demand-side or curtailment programs.

Response: Some very large customers have invested in mechanisms to decrease load when required and be paid for doing that. I would expect more of that behavior as prices increase.

Response: ERCOT's demand-side working group has been studying how to use load as a resource in the ancillary services market. I have not seen much change in the residential market. We hoped that retail providers might start using energy efficiency as a competitive tool to win customers but it has not yet happened.

Comment: From a public policy perspective, the more opposition there is to going from a zonal to nodal pricing system, the more important it is to do it. If there is not much opposition, the implication is that there is not much difference in the prices and so it does not cause much harm to socialize and spread.