Harvard Electricity Policy Group
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RAPPORTEUR'S SUMMARY*

Session One: Grid Planning and Expansion: Who, Where, When?

The debate is now familiar. Everyone recognizes that the complications of limited transmission capacity present major obstacles to a well-functioning electricity market. The direct cost of transmission is a small part of the delivered cost of electricity, much smaller than the indirect costs of congestion and curtailment. Yet the real challenges of grid expansion have created a cadre of experienced practitioners who caution that increasing capacity is easier said than done. The introduction of markets adds new dimensions to old problems. In theory, with appropriate pricing, market incentives can support merchant transmission investments, but only if the rights and rules develop to support the efficient investments. In practice, network interactions and free rider problems leave open a need for coordinated planning and regulated investment, but the new market environment tends to reinforce the incentives to free ride. Responsibilities for grid planning, evaluation and expansion should be organized to some degree under Regional Transmission Organizations, but the ambiguity of authority complicates every aspect of that continuing debate. All the while, grid expansion stalls, apprehension grows, and the questions remain. What are the rules? Who will expand, and who will pay? Where? When?

Speaker One

For purposes of making my comments this morning, I am making the assumption that it is the year 2002 and an RTO has been formed in New England. How might grid planning and expansion work within an RTO?

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

One model for who is going to do the transmission planning and expansion might be a “gridorg”--a for-profit entity, operating under an incentive rate structure, that is part of the RTO. Transmission planning would be done by the gridorg, and expansion would be undertaken by the gridorg and by merchant transmission developers. Although I am talking about New England, this model can be and ideally would be expanded beyond New England. We believe this could be implemented by December 15, 2001, FERC’s target date for having RTOs up and running.

In terms of structure, this model consists of two entities--a gridorg and a modified ISO. The gridorg would be composed of entities that own and operate transmission facilities in the region, with a contractual arrangement among transmission providers. There also are some functions the ISO would perform that could be performed by a contractor. The gridorg and the ISO are two separate organizations. Collectively, they possess all of the characteristics and perform all of the functions set out in Order 2000 for an RTO. These boil down to issues relating to open access transmission and reliability. What the RTO doesn't do is that associated with the power exchange and market issues.

The gridorg would be independent, governed by a body that meets the criteria of Order 2000. It need not have employees or assets; it could be a contractual relationship for governing the transmission business in New England, comprised of entities that today are in the regulated transmission business. So transmission owners could retain their assets. The gridorg would have the open access transmission tariff for the region.

For governance, there are several models by which the gridorg can govern itself in a way that's independent. When you have two parties that are part of an RTO, though, you have to define who does what. So it makes sense to look at the various functions the RTO will perform. Are there certain functions that make sense to have done by a for-profit entity under an incentive rate structure? If so, those are the functions on which the gridorg would lead. If there are other functions where it doesn't make any difference if it's performed by a non-profit or for-profit entity, those functions could be performed by either the ISO or the gridorg. The touchstone is what structure is likely to drive value for customers.

An example: If one of the issues is controlling congestion costs in New England, and you believe that this is something where a for-profit entity with incentives tied to controlling congestion costs makes sense in providing value to customers, that would be a function you would assign to the for-profit gridorg with an incentive rate structure.

With regard to planning and expansion, there is a broad consensus in New England that there should be a five-year regional plan, prepared annually, that the plan should identify the grid upgrades needed for reliability, and that it should provide information that will identify potential opportunities for economic upgrades.

Note that I am distinguishing between reliability upgrades and economic upgrades. Reliability upgrades are those needed to satisfy the reliability design standards in the region. For instance, if load growth is forecasted to increase in a particular region, and we see that the system cannot continue to operate and meet the design criteria that have been established, then the upgrade needed to remedy that would be a reliability upgrade. On the other hand, upgrades that may not be necessary to satisfy reliability design standards, but when you look at the system and the congestion costs on the system, an upgrade may make sense as an economic resolution, that is an economic upgrade. I distinguish between the two because it may make a difference as to who pays.

The gridorg would have the lead responsibility for preparing the annual five-year transmission plan for the region, and it would do so through an open and transparent process. The ISO and all stakeholders in the region would be involved. Everybody would see the criteria and assumptions being used to prepare the plan. For example, if someone proposes to build a merchant transmission line, that may remedy the need for a further reliability upgrade but, ultimately, somebody has to have the responsibility for building new transmission so the system can continue to operate reliably, and we propose that would be in the gridorg. With regard to economic upgrades, any entity that wishes to could build economic upgrades of the transmission system provided they're able to get the necessary regulatory approvals and the legal rights to do so.

Who would pay? For reliability upgrades, we propose that all gridorg customers pay through the regional transmission tariff. To the extent that new economic upgrades are built as merchant facilities, they would be paid for as part of the market deal. Market participants would enter into their own commercial arrangements with the developer. However, you have the free rider problem where you build the new facility in the middle of the grid. If it's not a DC line and you haven't put in devices that will control the flow of electrons, they aren't going to belong just to the party with the property rights. Market participants may not want to put up capital to build that facility. With this model, the gridorg could step in and build the economic upgrade because it makes sense for the region. It would allocate the costs to those who benefit from construction of the new line.

This model has been proposed by seven companies that are in the regulated transmission business in New England. It is also expandable to other regions. We see it as a vehicle for implementing regional grid planning and expansion that goes across existing market seams. There is a memorandum of understanding that the IOUs in the Northeast have entered into, looking at a larger region. And we believe that movement on the part of transmission companies that cuts across existing seams and enters into this type of gridorg arrangement is another way of permeating the regional market seams and creating a larger system without transmission barriers between the markets that exist today.

Speaker Two

We believe there is a market model that allows competing transmission providers to build the right projects at the right places and the right time if they have the right prices.

I use three fundamental assumptions to think about how to organize a competitive electricity market that produces lower prices through competition. In the short term, spot market pricing for electricity leads to productive efficiency. In the medium term, centralized investment decisions based on those resulting market prices can maximize allocative efficiency. We've seen that on the generation side, where we allow the market to decide how much generation is built and where. In the long term, technical innovation that is responding to these market opportunities can increase the dynamic efficiency of the markets and lead to the deployment of new technologies. With the right details, merchant transmission is not only possible, but becomes the logical vehicle for expanding the grid.

In an electricity market under a FERC-approved RTO, which has a market-based congestion management system, locational-based marginal pricing (LBMP) and firm transmission rights (FTR), perhaps the biggest unresolved issue is grid expansion. I also draw the distinction between expansions for reliability, which are social decisions, and expansions for congestion relief, which are commercial decisions that can be fully put to the market. Merchant transmission is financible. It gets built, and it's financed through FTRs or their equivalents. It's efficient because it leads to the right project at the right places at the right time. Merchant transmission unlocks dynamic efficiency, because the entrepreneurs and the incumbents can respond to these market opportunities, and that leads to technical innovation.

Why are there grid expansion issues with LBMP? The biggest problem is that any new transmission has commercial implications. Some generators are hurt; some are helped. I'm sure everybody knows the statistics about the declining circuit kilometers or miles of overhead transmission in the U.S.

What are the options in the market? One is to require full integration for new generators. What's enough? Who is going to determine it? We're not really on a path in that direction. Option two is using central planning to relieve congestion. Then congestion emerges because the generators go where it's cheap, and the central planner has to guess about future loads, fuel costs, all the things that led to the problems on the generation side. The last option is to allow the market to decide what gets built, and that leads to merchant transmission.

How does it work? What drives the value or the prices of the FTRs? Two things: The expected spot differences in LBMP, and the risk aversion of the market participants, will lead them to pay more than just the expected value. Competing generators can now evaluate new projects and decide whether or not the future value of the FTRs will cover their cost--except now their cost includes what they'll accept as a return on equity for the risks. If the market value is greater than the project costs on a market basis, the project will proceed. And if it's not, the project shouldn't go forward.

A merchant generator, or anybody economically relieving congestion, shouldn't have the power of eminent domain. Why should you, as a landowner, put up with a transmission line in your backyard so that some generator can get more money? Our answer has been to go to underground cables, but there are plenty of other technologies, and they will grow over time. And there are many financing options for competitive merchant generators. You can pre-sell the FTRs to other market participants or just hold onto them and cash the value out in the normal FTR process.

What about the existing wires? They are going to produce most of the new FTRs, but there are some cost allocation issues. One idea is to treat some transmission costs the same way most places have treated some generation costs: Collect the market revenues from the FTRs from market participants or the congestion rents for transmission rights that aren't sold. Have a non-bypassable grid access fee. The owners of the existing assets get their regulated cost of service, and it's a way of treating the existing wires in the same fashion as we've treated existing generators. The regulatory compact remains. And you don't have to give incentives to the existing wires just to get new transmission built.

What are the benefits of merchant transmission? There are no new stranded transmission costs. Dynamic efficiency is the real prize. New technology that not only increases transmission capacity, but does so in better ways for society as a whole. And a more level playing field among all resources that provide delivered electricity service to the customer. Better RTOs, and better siting rules for congestion relief.

Is there a role for new regulated transmission? Yes. It has been suggested as a backstop to ensure reliability, but if you can raise the risk of congestion enough, you don't even need that backstop. If an RTO or whoever does the central planning for reliability identifies a needed grid upgrade, they should put the construction, ownership and financing of that asset out to competitive bid. Is there any role for new regulated transmission for congestion relief? My view is no. The markets can work if they are given a chance and the right signals. Mitigating market power? No. There are cheaper behavioral or structural solutions, such as bidding caps on key generators.

How do you deal with free riders? Bankruptcy is bad, and the corollary is that if you're an electricity market participant and you see price volatility and don't want to go bankrupt, you buy enough property rights to protect your position. Demand for property rights can ensure that free riders don't have them. Somebody in the value chain has an obligation to serve firm retail load. If markets are well designed, free riders are discouraged. And there are new technologies that give more control over free riding.

The classic view of transmission is that presumed scale economies are greater than or equal to the commercially efficient amount, which is less than the social optimum. Market demand for the assets can be calibrated to match the social demand. You can use risk aversion plus volatility to get the right amount of market demand. If there's too little of anything being built in electricity markets because of free riders, just keep raising the pain of not being hedged during scarcity. In properly functioning markets, people should go bankrupt.

Is it worth the effort? I've heard people say, well, transmission is only five percent of the total retail cost of electricity, so why go through this Herculean effort to get there? Oh, but the marginal cost might be ten times that. If you get the prices right at the margin, the right amount will get built when and where it should be.

What prevents a merchant transmitter from collecting monopoly rents? One, competition. The existing grid is a vehicle for getting other FTRs. Two, the overall market monitoring function of RTOs--and I'd suggest that merchant transmission developers could fall under that as well. Three, how does a new resource create monopoly rents? Maybe I've transferred some monopoly rents from somebody else to me, but I think that's good.

The combination of LBMP, FTRs and merchant transmission promote all of the efficiencies I've touched on. In particular, technology deployment requires market opportunities. Merchant transmission helps RTOs because they won't see any further stranded transmission costs. You get enhanced grid reliability. You can provide incentives or not for the existing wires. This model is on the ground in Australia, and putting it on the ground in the U.S. just requires realizing that, with the right prices, the market will respond.

Speaker Three

PJM and New York do have market-based transmission investment. The next steps are more confusing, and sometimes acrimonious. How do you design a system or a process to encourage private investment? PJM and New York are beyond that because they already have a tariff that says what you should do.

So, we're onto the next step: When? What do we want to see happen? The bottom line is, you want to be able to attract capital. There is not a simple formula for that. We have a general notion that we want to have clear property rights. We want to have predictable valuation, rules, etc. for how we're going to set prices, how the system in which those property rights are embedded is going to operate.

What do we want to see as a general solution to implement market-driven investment? Locational pricing--a recognition that the spot or real-time value of transmission is the difference in locational prices. Then creation of property rights associated with that real-time valuation. The next stage is how to actually implement that in the embedded process of the rules. That is a lot more complicated.

The current situation is that in New York, the tariff is explicit. There is an agreement in principle that the incremental rights for new facilities, TCCs, go to the party that makes the investment. New York is arguing over the policy on the measurement and award of those incremental rights. Because there is a split market that has installed capacity requirements, people are starting to ask whether there is a property right associated with new transmission facilities that relates to capacity, as opposed to just energy.

PJM clearly has agreement that incremental rights are awarded to investors in facilities only when associated with new generation interconnections; PJM also awards related capacity rights. Alternatively, while PJM has fairly sophisticated implementation of these rights associated with new capacity, it explicitly does not have a generic policy that, if you upgrade the transmission facility as a private investor, you get the incremental FTRs. We have to get that onto the agenda.

In looking at how the two pools have proceeded, it becomes apparent that the simple model takes a lot of twists and turns. First, this is not a generic LMP process that says I know the locational prices, I have an energy-only market, and all I have to do is award incremental rights. It comes into a full-blown system that has lots of historic precedent, negotiations, and compromises in market design structure.

Second, we talk about creating something incremental, but that's hard to measure, particularly when you start getting into multiple improvements, rights contingent on valued configurations and use of the system. What are the specific properties of the award? Is it a long-term firm obligation? Is it cancelable? And regulatory status is an overlay.

A third is integration with the rest of the RTO/ISO process. If you start in a non-market structure for establishing how rights go, that is like an embedded cost issue. There's a fixed base, and we ought to be able to overlay a market-based system. But a lot of people associate that with the allocative or equitable allocation of rights that started the system. That mindset and that belief in entitlement to those historic rights creates a mental barrier. So I am cautious in designing systems about what we say about initial rights and allocations, and to make sure no one thinks that creates some sort of process entitlement.

New York and PJM do allocation drastically differently. New York has an auction process, a very good idea. PJM has an archaic process that links the allocation of rights to some notion of network resources that you've relied on in the past. There is a hierarchy of those, and it creates a fairly rigid overlay that reduces a lot of the flexibility about how people can value and move things in the future. It also means that PJM, for example, can't have long-term option markets for FTRs--a major limitation.

Another type of allocation is who gets the rights to the excess deliverability in the system. This is the queuing problem. There is a real-time issue in New York, which sends the message that the first person to raise their hand gets an entitlement to transmission rights. In PJM, on just two grandfathering switches--where people lobbied to be able to jump the queue--there were transfers between the parties and, most likely, away from ratepayers of over $100 million. That kind of cost-shifting has major commercial implications.

In terms of interactions with central planning, just sticking in more transmission that is paid for by everybody in aggregate or allocated to the “people who benefit” tends to degrade the property rights of other participants in the market who may have paid for those rights through their own investments. On the other hand, certain facilities must be built for reliability purposes. We need to minimize the central planning function. At best, it should look for reliability fixes only and as a last resort. A good thing it could do is advertise opportunity. You let the market work as fully as possible and only at the last minute step in with the minimum reliability fix.

On market design, both PJM and New York have separate capacity markets. PJM has explicit, well-developed deliverability criteria. New York hasn't dealt with it. People who create upgrades and transmission for energy purposes do the same for capacity, and we have to come to grips with how to deal with that. The more we do it, and the more explicit we get in terms of developing capacity-related property rights, the less likely that we will ever shift to an energy-only market.

How do you measure what's incremental? The baseline use of the system can change based on either participant bids for TCCs-in New York--or designated network-based FTRs-as in PJM. A general approach is to look at what is incrementally feasible given the existing uses.

We have introduced a concept where the property right, instead of being an FTR or TCC, can be an entitlement to revenues based on the sale of those rights in the system, which is a much more flexible configuration. They're referred to as auction revenue rights. PJM has created a system where you can give up the rights you were given, so long as no other party is dependent on it. New York hasn't dealt with this.

Who owns the improvements? That has a lot of practical implications. Now that I've walked away with these TCCs or FTRs or capacity rights, is there a regulatory status? FERC tariffs have approved this kind of process.

Speaker Four

My premise is that advanced technology can relieve constraints, if someone will just invest. On the basis of this premise, we decided to see if there was a way to invest in transmission upgrades, find the constraints, and upgrade them.

The directive was to make money while eliminating bottlenecks. The idea of making money is important because it's tough to get people to invest in something where there is no return. We looked at re-conductoring using high temperature conductors; incremental reconstruction of 345 and 500 kV segments that were needed in certain areas where a short piece of line could improve the capacity; replacement of sub-sea cables with solid dialetrics to replace leaking oil field cables; adding cooling to oil field cable systems; and even using non-electrical right of ways as far as putting cable in abandoned pipelines to use for conduit.

How did this come out? The reality is this that there are substantial obstacles to construction by a non-incumbent utility. First is the difficulty of structuring the deal under PUHCA. We referred to it as the PUHCA Pretzel, because we were trying to come up with a structure under which we could invest and not become a public utility holding company. The second issue is that transmission projects are perceived to be low-risk, so they receive low returns and recover their capital very slowly. That perception of low risk is not true. In fact, some merchant transmission projects may be very high-risk, higher than a combined cycle plant in an urban area where there's a good market.

What are the risks? There is a lack of a generally accepted business model for transmission as a merchant line. We don't quite know how to deal with that, and part of that is that there is no forward market in transmission. If we are going to build as a merchant, we have to have a long-term forward market, because these are not short-term investments. Who will buy that capacity? Somebody who wants to import generation into an area, who has a low-cost resource that's remote from the area and wants to deliver generation into a load center.

Acquiring right of way without eminent domain is a problem. Burying pipelines is a difficult task. Whether you are burying a DC or crossing with AC, nobody wants it in their backyard anymore. And even if you get the eminent domain and right of way, other obstacles will be erected. There will be protests about radiation and appearance. They will withhold building permits. And a real difficulty is getting agreement from the existing owners.

In terms of PUHCA reform, we have to take a different look at whether transmission really is low risk, particularly for merchant projects, and let the market define its value. Otherwise, the benefit is going to be captured by someone else.

A few questions: Who is going to take the delivery risk, the customer or the service provider? This goes to the issue, what's a reliability matter and what's an economic matter? It is a broad spectrum, and there is no complete answer. Can one party effectively plan the investments and another make them? I think there is a disconnect there. If I'm going to risk my money, I'm going to run the plan. I talked about the forward market and the prospects for price legislation. Is there anyone out there, in today's dot com world, with an appetite for long-term assets with relatively low returns over time? Is somebody willing to make a thirty-year investment? A few foreign companies apparently are, but I wonder if any American companies are.

Finally, people talk a lot about distributed generation and local generation in the service territory, but the energy has still got to be moved there. Is it going to be in transmission lines? Is it going to be by gas pipeline? Gas pipelines have some of the same problems of expansion that electric transmission lines do.

Discussion

Question: Let's say you have a project identified as a reliability project--a constrained area with load growth--and it has a five-year lead time, and a year or two into it the generator decides to locate within the load pocket, so the transmission line is now no longer a reliability project. What is your proposal for dealing with the costs incurred in pursuing that project up to the point it got deferred?

First Response: If you already incurred costs, they should be recoverable under the tariff. Otherwise you have a situation where you are creating a real disincentive for the people who have the obligation to build the reliability project. If it's going to work, there has to be a recognition that the costs were prudent up to that point in time and are recoverable. Then the question becomes, is it still prudent to build the rest of the project, or is it more prudent at that point to abandon the project?

Second Response: One, you don't want to identify reliability upgrades and start spending the money until the last minute to minimize the probability of this happening. Two, many technological innovations can cut this time down quite a bit. On our Australian projects, we're down to about an 18-month project cycle.

Question: What are examples of transmission upgrades that were reliability only and where entities would not build them willingly? Why won't people build them? Is it that the market is not well-defined and no one is going to take the risk?

Response: In theory, we would allow for the disruptions--we'd allow for a degradation of service to the point that prices got very high. We would be dropping load, and that would set prices. The other things are where people start to discuss stability criteria. I take it on faith that with certain types of improvements that are necessary, it is not clear that they are going to be manifest as incremental rights anywhere. Yet it is a necessary value in the system.

Comment: There is lots of overlap between reliability and economic upgrades. The gridorg could invest in economic enhancements. I love the idea of using a profit motive, but worry about independence.

First Response: Yes, to the extent that a gridorg is building economic upgrades as a regulated investment, there is potentially competition between the gridorg and others who might want to invest in transmission as a merchant business or build generation in the marketplace. If you have a plan, and it gets information to the market, then market participants can decide whether or not this is an investment opportunity for them. If they do, the gridorg should not build the economic upgrade as a regulated investment. Still, policymakers need a mechanism to look at a region and say, it looks like it's economic to build a transmission upgrade to relieve congestion here.

Second Response: There is no reason for the gridorg to build economic upgrades. Economic upgrades are virtually by definition competition against generation. As for transmission upgrades required for reliability, all the tariff needs to say is, whoever builds it and successfully completes it gets paid their bid, not their regulated cost of service.

Third Response: Reliability vs. economic is a continuum, so there has to be some decisionmaking process. Indego [proposed ISO] had a planning proposal that was coupled to the embedded cost recovery. It would have phased in to an area rate, and any future investment made for reliability would go to that area rate and a local planning activity would be involved in deciding what those facilities were. At the next level, the decision was what ratings you had to maintain to keep the system from going out. The idea was that there were consequences to adding these reliability issues, and if Boise wanted to have a redundant loop around it, then they should pay those costs, not the people in Salt Lake.

Question: There are so many pricing schemes. Until that is resolved, is it realistic to contemplate the value of a property right?

First Response: The best analogy I can point to are projects in Australia that have defined property rights based on the current electricity market structure there. That market structure could change to make the rights generated by the asset more or less valuable. That's a risk.

Second Response: The empirical test is probably the best. Companies developing merchant plants are evaluating investments as if they were in a locational scheme.

Comment: Australia is an example where property rights can exist, and the first project we put into service there had zero long-term forward contracts and was financed purely as a merchant facility. It depends on clarity of the regulatory structure.

Question: I'm nervous about this distinction between reliability investments and regulated economic investments. I think the danger is that if I were proposing something, I would call it a reliability investment because nobody could question it. If we want an operational criterion, it seems most practical to have the gridorg demonstrate that one, it's economic, and two, there is a significant market failure so that there is an argument about why the free rider problem dominates. This has two advantages: It provides a threshold and it deals with problems about why someone doesn't deal with a peaking plant, because if you have the pricing right they'll be doing it. Why isn't that part of the package?

First Response: If load is primarily local in character, that tends toward the reliability side. When it is non-local, it points in the other direction. If someone wants to build a line from Quebec into New York City, that's clearly market expansion. If they're trying to solve a problem in the periphery of the Boston area because of local load growth, that may be local reliability, so my preference is to tie that to a local cost paid by the local parties. But eventually you'll get into situations where there isn't a clear distinction.

Second Response: The public policy problem is that not enough transmission is being built. We need to strike a balance that allows an opportunity for market-based investment in transmission, but not worry so much about the construction of transmission in the regulated environment versus the merchant environment that we make it unduly difficult to build transmission in the regulated environment.

Comment: In certifying gas pipelines, FERC always looks at whether or not there will be a system benefit to the pipeline going in. That is something important to look at in a regional context. The RTO process can help make the case for a system benefit when construction is proposed.

Question: In terms of the independence issue raised earlier, the credibility of the entity that is putting forth to FERC the rules for a region is critical for people investing and believing that there'll be a balanced way that these things are coming forth to FERC. There ought to be a transparent way that the potential conflicts there are understood by everyone in the marketplace so they can be contested at FERC. How have you dealt with this?

Response: You're right--for this to work, the gridorg has to be independent. I think the governing structure proposed for New England does that. The gridorg would consist of the entities in the region who are in the regulated transmission business and not also in generation or selling electricity. The way you structure the incentives becomes very important. I think the bias for deciding just in favor of building transmission can be addressed in how you construct the incentive rates.

Session Two: Retail Markets Over There: Has Supply Competition Taken Root?

Other countries have opened their retail electricity markets to supply competition. In some, suppliers have joined the fray and consumers, large and small, have availed themselves of choice. In others, while the retail market has opened up in theory, few customers have switched suppliers, and marketers have not entered the market in any meaningful way. What can we learn from these experiences? What barriers to entry have been encountered? How is it that these barriers have been overcome in some jurisdictions and not in others? How have consumers been educated as to their rights and opportunities in newly competitive retail markets? How have they responded? Has there been considerable consumer lethargy, or active participation in the market? What margins do competing suppliers have to work with? What kinds of start-up costs have been incurred by new entrants? Who does the billing? Who owns and operates the meters? How far have the services of the local distribution company been unbundled? What residue of monopoly has been left standing? Is the local distribution company allowed to participate in the supply business? If so, what type of behavioral limits, if any, have been imposed upon them? Who has the responsibility for providing default service? How is the price for default service derived? What value added and efficiencies have new suppliers offered to consumers? Have retail *supply functions been bundled with other infrastructure services (e.g. telecommunications, water, natural gas) by supplier entrepreneurs? What does the future hold for the retail supply market?*

Speaker One

Since 1997, Spain has had a free entry generation system with a wholesale market organized around a pool and free bilateral contracts. Generators' revenue is based on market prices. In addition, there are some non-market revenues, particularly a capacity charge and competition and transition charges. Transmission and distribution are regulated monopolies, with regulated access, i.e. free access for any eligible consumer, and a regulated access tariff. Remuneration is, for transmission, incurred and acceptable investment and O&M costs, and for distribution, investment and O&M costs.

We have a sophisticated design for the wholesale market. There is a daily market, an intra-daily market that works every four hours, and an ancillary services market. It's sophisticated in relation to, for instance, the United Kingdom, which began with administrative solutions to ancillary services.

Spain has developed a highly sophisticated design, but with very few players. The problem is the industry structure. We wholly privatized. But there was insufficient vertical unbundling. There is not ownership unbundling of distribution, but different legal entities. We have a separate system operator, but the incumbent utilities are the main shareholders, with 40 percent of the capital. As to horizontal concentration, there is no limitation under the Act like, for instance, in Argentina, where not more than 10 percent can be in the hands of one generator. Mergers have been authorized by the government to the point that 80 percent of generation and distribution is in two companies.

Since privatization there are only four utilities, two big and two small, with generation and distribution. The system operator is 40 percent owned by the four incumbents, as is the market operator. Retailers are the four incumbent utilities plus two new ones, Enron and a Nordic trader. Spain has an isolated system; there is no commercial interconnection with Europe. That is a big problem. Spain is an island, electrically speaking.

In retail competition, consumers follow the system of the European community that is granting step by step the possibility to select a company, and therefore we have two types of consumers: Captive consumers, those with regulated tariffs, who are supplied by the distribution utilities; and eligible consumers, who can buy from any supplier. The terms are up to the contracting parties, and they can stay under the regulated tariff. The retailers are in a strange situation, because they buy from the pool and sell to the eligible consumers, but they cannot buy directly from generators. The incumbent distribution utilities are allowed to sell retail using a separated company. There are no Chinese walls among distribution and retailers of the same group. And incumbent distribution utilities do not have to provide information to new entrants.

In giving opportunities to the eligible consumer, Spain has gone a little farther than the EU directive, but not as far as Sweden, Germany and the UK, which offer all consumers the possibility to choose. Currently, 10,000 consumers can choose. They can go to the market or remain.

In regulated activities, there has been no change in transmission or distribution. In market activities, there is no change in generation; 100 percent is supplied by the four incumbent companies. Imports are also controlled by incumbent companies. For retail sales, .06 percent has been supplied by new entrant retailers, 99.94 percent by the incumbent retailers.

In 1998, few consumers went to the market. Then the government decided to make a substantial reduction in access tariffs and capacity payment to those consumers who shifted to the market. As a result, most eligible consumers went to the market. But new entrant retailers did not get consumers, and there was no switching among incumbent utilities. What happened is that they didn't select the consumers. There are no bilateral contracts, because there are no generators, no direct imports, because they were controlled by the incumbent, and insignificant purchases to the pool.

Why did we get good results in consumers going to the markets? In my view, it is because the government gave to eligible consumers a substantial reduction of 40 percent in access tariffs. According to a study at the Commission, in 1999 the reductions if the consumer went to the market were 30 to 37 percent.

Why the poor results for new entrants? We are only two years into this, so it's probably too early to judge. But the incumbent utilities are very competitive. And there are problems: The incumbents are using their non-market remuneration, the standard cost capacity charge and so on, to retain customers; and the insufficient vertical unbundling permits distribution and generation and retailing in the same company.

With horizontal concentration, the incumbents have enough power to decide the pool price. Retailers without generation cannot cover the price risk. Other problems are non-independent regulation--the government is the regulator, and the Commission is just an advisory body. Regulation is unstable. We have had three different access tariffs in two years and two different capacity charges in two years. Consumers who want to switch must overcome many administrative obstacles.

What are measures could be taken? Tough measures would be real unbundling and divestment to reduce horizontal concentration. Others are free access to all consumers, leaving additional generational capacity to new entrants, and allowing retailers to become external agents and sign bilateral agreements with generators. Separating metering from distribution probably would help, as would forcing distributors to give information to retailers. It would help to assure consumers that quality does not depend on the retailers selected, because at this time, the consumer is not sure if they are going to lose if they contract with a retailer that is not the distribution company. And educate the consumer. The other possibility is to wait and see what happens.

The forecast includes negative developments, in more mergers coming and discussion of incumbent utilities also being allowed to control the gas network. A positive development is that the new government has promised to open to all consumers the possibility to choose. This is not going to solve any problem, because the problems are structural, but politically it could have an enormous impact because it would allow the whole population to see what the problems are and force the government to deal with the problems.

Speaker Two

Development of the Scandinavian market has been an ongoing process for 10 years. It started in Norway around 1990, and has gradually evolved. Sweden has had new electricity regulation since 1996. There are many actors in the markets, both generators and distribution companies. Sweden has 10 large generation companies and 300 distribution companies, Norway has 60 generation companies--though it’s a small country--and 250 distribution companies, and Finland has two generation groups and 120 distribution companies for a total 330 TWh hours, and it's pretty much one market.

A lot of the system is hydropower, and that is important because there is a big difference between a dry year and a wet year. Hedging is the main issue in the market.

Fundamentals of the new market are, first, separation into three businesses. These are the network operation, electricity trade and retail, which is not a regulated business today except for a temporary supply license to protect small customers, and generation, which is not regulated from a commercial point of view. It is regulated from an environmental point of view. They are separate companies and are separated by books.

The second important part of the new market design is the point of connection tariff. There is a separate network tariff for each generator and each consumer. We have the same tariff regardless of supplier. This means that the network owner can never block trade or in any way discriminate one trader from another. The network owner can, of course, set tariffs that lead to inefficiency or are regarded as unfair.

We have a voluntary spot market, and quite a lot of bilateral trade, so there is no obligation to go to the spot market. We have a balance market that is open to all suppliers and organized by the system operator. On the active side, you have bids for frequency control for the system operator to keep the frequency in the system. But in this respect, the important thing is the passive side, where you have the settlement of unavoidable unbalances. This is a very small cost for the trader, but it's extremely important to have access to this market and have it priced in a way that you are not discriminated against by large generators.

Finally, we have a well-functioning financial market for hedge contracts. It's a liquid market. This market was quite small in 1995, but has gradually increased.

The market is designed to make it easy for new suppliers to enter the market. You buy power from the spot market or bilaterally. You trade on the financial hedge market. You sign a contract with the TSO for calculation and settlement of unavoidable imbalances. Installation of meters and meter reading is taken care of by the network operator, for efficiency reasons. The setup makes it very easy for a trader to enter the market. You don't need that kind of infrastructure or knowledge. You don't have to concern yourself about the network tariff. And there has been a large difference between the wholesale price and the consumer price. There has been a big margin for the new actors to come in and try to compete on.

If you look at the different consumers, roughly 30 percent of the total market is electricity-intensive companies, steel factories, paper and pulp, and so forth. They usually signed long-term contracts before 1996. They relied on their negotiation power, and didn't believe in the new market. They have been displeased these last years because they are paying more for electricity than households. They still try to lean on physical contracts signed with the large generators.

Small consumers-households--are about 35 percent of the market. They were locked in because of a requirement to install hourly metering. The cost was initially about $1,000. In 1997, it was by regulation limited to $300. Since October 1, the cost is zero. They introduced a system of profiling instead of the metering requirement. There was hard pressure from consumer groups to get there. Before 1999, less than one percent had changed. From October 1999 to February 2000, seven percent switched, and 18 percent negotiated the price with their present supplier by signing a one-, two- or three-year contract in order to get a lower price. One company has taken about 30 percent of this seven percent, and they are really competing with more efficient billing. They said they could reduce billing costs by 10 percent.

Medium-sized customers are about 35 percent of the market--companies like real estate, manufacturing, transportation, telecommunication, hospitals, supermarkets, gas stations. They have been very responsive from the beginning, and today almost 100 percent have changed suppliers or renegotiated their price. These companies usually have a lot of sites, but have a central organization for purchasing. So a real estate company will typically buy 50 to 500 gigawatt hours per year, split between hundreds or thousands of premises all over Sweden and even Scandinavia. These companies often go into portfolio contracts with some spot, some medium-term contracts, and some long-term contracts.

Retail margins, for a large customer, could be around $100,000 a year. For a medium-sized customer, it is down to around .03 cents per kWh, or $30,000 a year. Most surprising are the margins when you go to small customers; a small customer today can buy with a margin of .2 cents per kWh. For a household with electric heating, it's around $60 a year; for a small house without electric heating, $15 a year; and an apartment, $6.

The retail business, in my view, is billing and administration. Larger customers look for the ability to get advice about hedging strategy. That is what is important for a customer today; it's not really the margin, because the margin is so small. Retail is taking risks--price risk, volume risk, congestion risks, imbalance cost risks, currency risks-and it is trading.

Is retail competition a good thing? On the positive side, price regulation is a poor substitute for competition. And the new suppliers have vitalized the industry. They focus on what the consumer wants, and don't try to force something on them. They introduce new products and synergies, like selling telecommunication with electricity. And there is a new player on the wholesale market.

On the negative side, there are extra costs for metering and billing, and this has been a problem. It is difficult and time-consuming for the consumer to choose--although even if you don't choose, you get the benefit from competition since prices are going down. And municipal- and state-owned companies are involved in a high-risk and low-margin business.

Speaker Three

England and Wales used to have a single company that did 95 percent of generation and transmission. Twelve distribution companies did all of the low-voltage distribution and had a monopoly on all customers. Because they were somewhat subject to the monopoly generator and transmitter, we had a de facto vertically integrated, state-controlled industry.

We now have lots more generators. We have a completely separate, privately-owned transmission company which does only high-voltage transport work. We still have 12 distributors, now called regional electricity companies (RECs), which retain a monopoly over the local wires business. As of one year ago, all customers are free to choose a supplier. We have had a lot of difficulties in introducing the final stage of small consumer competition.

The structure of the wholesale market was originally a compulsory pool. But we always allowed bilateral contracting, which could override pool prices in terms of final prices and settlements. We protected our inefficient, high-cost coal industry, as well as our nuclear power industry. And we then started protecting our new combined-cycle projects because they signed 15-year fixed-priced contracts which became stranded because the wholesale price started going down. So we had a lot of stranded cost recovery. For coal and independent power projects, the stranded cost recovery was always loaded onto that part of the retail market which remained captive. Only the stranded costs in nuclear were loaded onto the entire market. So part of the politics of opening the market to all consumers has been to make sure that the stranded costs are equally shared across all consumers.

We had very limited early competition in generation, and that inflated prices above new entry cost levels. It has made new investment extremely attractive. Having struggled for some years with the Pool, we have decided to abandon it and to introduce a new wholesale market system which tries to mimic the Scandinavian system. It will probably favor larger generators and will, I think it's fair to say, be something of a mess.

On transmission, we've had a separate, privately owned company since 1990. We've had pretty strict enforcement of transparent and equal use of system charges. And we have had a price cap system; prices for transmission and distribution can rise out of the retail price index less an efficiency term we call x. The efficiency term is set periodically by the regulator for a four- or five-year period. These x terms were generous until 1995, but since then the regulator has gotten tougher. Charges for distribution and transmission services are now only at about two-thirds of the level they were in 1990.

In 1990, we set out a timetable for retail competition. Immediately, all customers with a load of 1 MW or more were free to choose their supplier. In 1994, customers with 100 kW demand or above were free to choose. There were many delays in opening to all customers, but we now have.

Suppliers have to have a license from the regulator. What we call a first-tier supplier is a business operating in its home market. A second-tier license is anybody else, including a regional company acting as a retailer outside its home territory. Any generator may also become a supplier, as long as it has a separate business. We do allow our distribution companies to retail, which is a matter of great controversy. The two activities must be completely separated, yet you still are allowed to both own a local wires business and be a retailer. We haven't had many new entrants in retail supply. Originally, the only significant new entrants were generators acting in the capacity of retailers, and they were interested in very large customers. In the smaller market, we've really had only British Gas, a large private retail company. We've had hardly anybody else in our retail market.

Everybody in the market over 1 MW must have half-hourly meters. Meter ownership, operation and reading are all open to competition. A large number of companies are competing in the meter business in a small number of large markets. The greater part of the price falls have been due to the fact that this segment of the market was exempted from stranded cost recovery. We haven't had many other kinds of value-added services, except a few financial ones. Very large consumers have been targeted by the big generators, and switching suppliers has become increasingly common.

Retail competition in the 100 kW to 1 MW segment opened in 1994 without adequate preparation and chaos in both metering and billing. Nevertheless, we had some big price reductions immediately, again because this segment of the market was exempted from all stranded cost recovery except nuclear. There were limited offerings of new services. A majority of customers in this market have switched supplier and may well do so again.

The most problematic sector is households, or everyone below 100 kW. Most use natural gas for heating, so retailing of gas and electricity jointly is the major mode of competition to households. We have only had one serious new entrant, British Gas. We gave up hope some years ago of introducing new metering technology. By continuing with our old metering technology and using a profiling system, we have retarded technological progress in metering since there is no incentive even to experiment with it.

There have been enormous transaction costs to setting up this new market. The regulator is allowing RECs, which have had to bear the main burden of all these changes, to pass through over $1 billion worth of costs to consumers over the next seven years to recover about 95 percent of the set-up and operating costs. The electricity pool is being allowed to pass through $100 million for set-up, plus another $75 million annually for five years. There may end up being $2.5 billion in costs passed to consumers.

Four million consumers out of 23 million have so far switched, which is 16 percent. Three-quarters of those have switched just to British Gas. Everybody is offering joint gas and electricity deals. There is much new regulation of service levels, many conditions for entry. You must offer supply to any consumer in the area in which you've been licensed; you can't just cherry pick at random. There are rigorous codes of conduct, cooling off periods, etc. The incumbent RECs also face a wide range of financial and service standards of performance, which are published annually on a comparative basis. We haven't yet resolved supplier of last resort problems. *De facto*, it is the incumbent REC, but OFGEM wants to have power to appoint suppliers in the event of bankruptcy, though almost everyone else in the industry thinks that's a bad idea.

We still have price restraints for the final retail price in the small consumer market. They were introduced for two years, until 2000, and have now been extended for another two years. The intention is to have no retail price control from 2002. Whether or not that's politically feasible will depend whether we continue to have an environment in which overall costs are falling--although our price falls have little to do with competition. The safety net is that the maximum price chargeable should fall by nine percent in real terms to 2002.

OFGEM allows a 1.5 percent rate of return on turnover as the basis for calculating these price restraints, quite a small level.

The RECs continue to own the meters, and they maintain them. The new suppliers must provide meter reading and aggregation services. That can be done by a process of competition, but there's not much competition in metering in the small consumer market. And there are fears that RECs may delay meter replacement.

On questions of equity, we have three categories of household consumers: those who pay through a bank, simultaneously or in advance by direct debit; credit customers, who pay three months in arrears; and those with a poor payment record, who have pre-payment meters. This last category has about 4 million people. As you would expect, the direct debit customers get the best offers. The people on pre-payment meters hardly get any offers. When we first introduced gas competition, the price differential among households in the same regulated area was as much as 36 percent between the consumers who are most attractive to suppliers and those who weren't. The differentials in electricity aren't as large, but they're getting bigger.

Being a low-margin business, we've had hardly any entry from outside the electricity industry. The generators have been the only serious new entrants. The one genuinely independent new entrant is in deep financial trouble. Price restraints in the small market have made entry less attractive, but have been good for consumers. The only feasible entry strategies have involved combinations with other activities. To be a retailer now, you either need to be a generator as well, or you need to be a retail supplier of something else--in our case, almost certainly gas.

In conclusion, we've had a pretty good experience in the over 100 kW market. But price falls, in both generation and retailing, have been mainly due not to competition, but to falling gas and coal prices, stranded nuclear costs falling from 10 percent of consumer bills to zero, and increasingly stringent regulation of transmission and distribution. Our experience in the household market has not been very good; we've had huge set-up costs, limited benefit, and stagnation in metering technology.

Larger, richer, urban consumers are doing best, because they are genuinely cheaper to supply in a completely transparent and efficient market, and because they're less captive than poorer, smaller consumers because they are willing to spend more time working out what is the best tariff available for them. Still, it has been very important to open the small consumer market. We needed to spread stranded costs across all consumers. And there is the long-term risk that if the same companies are supplying both a captive market and a competitive market, they will find ways of loading costs onto the captive part. The question is whether regulation might have done better, especially for smaller consumers. We don't know. Small consumers have not yet benefitted.

Speaker Four

In 1987, New Zealand had one state-owned enterprise, which dealt with most of the generation and all of the transmission. There were 61 supply authorities, mainly statutory bodies with elected boards or municipal electricity departments. Jumping ahead 10 years, the single generator had been split into two, and the 61 supply authorities had become 39 power companies. It was a wholesale market, but virtually no retail competition. We had expensive time-of-use metering, and barriers introduced by the incumbents to protect their position.

So the government split up ECNZ again, into three more parts, and separated line and energy businesses by way of ownership. The industry introduced new metering standards, which were based on value at risk. If a meter was processing a couple of million dollars worth of revenue a month, then it had to be highly accurate. If it was processing $200 or $300 a month, it didn't need the same level of accuracy. We set up six categories of metering. We set up a customer registry, and profile trading was introduced. Information exchange protocols were introduced, so that retailers agreed as to the minimum amount of information that would be passed across from the losing to the winning retailer. And metering access agreements were developed. When profiling trading was introduced, we had a dramatic increase in customers switching, and it's escalating.

How do customers get to know they can switch? At first, our company had a bit of TV advertising. The media have put a lot of effort into explaining what's happening. They've also publicized the complaints and billing problems. Lobby groups have been letting their members know how to switch, where to get the best deal and so on. Ernst & Young did a survey on switching, and one amazing result was that 42 percent said they wouldn't switch because they were a shareholder in a local company. Because the power companies were statutory bodies, they had no owners, so when they became power companies, they gave customers shares. Of those that did switch, 92 percent said it was to save money.

Billing could be a barrier to entry for independent retailers because the systems are expensive, complex, and prone to mistakes. Customers are spread across the country. There are information protocols and people who need to be notified about changes in customer, like the line or the network company, the meter owner, the meter reader. There have to be interfaces with call centers, and you have to provide to the national reconciliation manager, every month, what your wholesale purchases are at each grid exit point. These add millions of dollars to the cost of the billing system.

Generally, the retailers own the meters; access to meters is agreed to on a reciprocal basis among retailers and done on commercial terms. Meters are priced at about 10 cents below the replacement cost, which again has upped the price. There is no protocol on meter reading. A company may be able to make a deal with the incumbent retailer. If you don't or can't, you have to set up your own meter readers in isolated and remote areas.

The incumbent is the *de facto* supplier of last resort. But if you switch from your incumbent to somebody else, there is no obligation to take you back. And there is no obligation on any retailer to offer their services to everybody who asks. So there is a possibility that people could fall between the cracks. A ministerial inquiry is looking into this.

The cost structure represents a sort of average at the time the split of line and energy businesses took place, so the operating profit is low on this end. The cross-subsidies stayed with the line companies, so possibly some monopoly profits are there. As a result of the split of ECNZ, plus additional generators coming in, there have been substantial reductions in the average wholesale price. But because most of the retailers are hedged, they're not seeing that benefit yet--but it may come through in the next year or two.

In summary, we've only really seen competition happening with the reforms that came in 1999, and those were separation of line and energy by ownership. Cross-ownership is limited, no more than 10 percent, and the regulations are very strict.

Some of the smaller line companies had local generation, so that was allowed, up to five MW. Above that, they had to sell. The result was that any re-seller who was selling more than two GW hours through a network was affected by this regulation. That included shopping malls, airports, factories. Some of them had to sell their energy business. But competition has been facilitated through the low-cost switching mechanism.

The line monopoly side of the business is facing the threat of price control regulation. Up until now, we've had lighthanded regulation, which works on the basis that there's a threat of regulation. There's an implicit rate of return, but you don't know what the rate of return envelope is, and there are disclosure regulations. So it's designed to provide total transparency on the monopoly side of the business, and also to provide this threat. The problem is, it's never been exercised, so it lacks credibility. The new government is threatening slightly more force than previous governments.

What I expect to see is a separation of ownership from operational line companies. A lot of line companies were locally set up, and the population had a feeling of ownership about the local line company. But because the energy business has been removed, these line companies don't have the cash flow, the ability to exist on their own. They are gradually combining in terms of management and operations. So there is a trend toward the equivalent of the ISO approach. The state-owned generators suspect that they will be out of the retail mass market. They're not very good at it, and not one of them has a critical mass of customers. For those small profit margins, we expect to see some concentration of retailers. We are starting to see new businesses starting up in terms of metering, meter reading, customer management, data administration, and field services.

In the longer term, there may be privatization of government-owned generation. The government may privatize the operation of the stations and retain the assets, which are mainly hydro. Generators will stay in retailing, but they'll concentrate on the very large customers, where they all speak the same language. And virtual retailers will be indirect channels that the generators will use, because they will be able to gather customers together, will develop brand loyalty and so on. But there will still be room, in the small industrial market, for niche players, people who understand metering technology and the industry that they're operating in, and probably able to exploit some of the profiling developments.

Discussion

Question: How are delivery services billed? Volumetrically or a flat per customer charge?

First Response: In the UK, it's done volumetrically, and in a crude and aggregated way. It's an issue we haven't really done much about.

Second Response: In Sweden, if you're a customer and you have switched supply, you get two bills, one from the network company and one from the supplier. The bill from the network company is not regulated, but the basic principle is that it should reflect costs. Usually there is an energy charge, and sometimes also a capacity charge.

Third Response: In Spain, theoretically you could have two bills, for access charges and for supply. But in practice, you just pay one bill. The retailer signs a contract with the consumer and says, you pay 30 percent less than last year, and the retailer pays to the distribution company in those few cases where they are not the same.

Question: You said that in New Zealand, the wholesale prices had been coming down but the retail prices had been going up. How does that break down?

Response: Wholesale costs have been coming down in terms of the average pool price, probably 20 percent. Retail prices for highly contestable customers-large industrials-have been coming down. There were previously cross-subsidies for residential customers, so prices were very low. Costs were loaded onto commercial customers. As the commercial customers became more contestable, they had to get rid of that cross-subsidy. So residential customers have had significant real price increases.

Question: The UK regulatory regime has no real rules about what are operating expenses and what are capital expenses. So they capitalize things like tree-trimming expenses. Is this going to end up as a huge write-off for the utilities?

Response: A major part of the price control reviews now for both transmission and distribution is the attempt by regulated companies to explain over the next four or five years what their capital budgets will need to be. On those, they are permitted a regulated rate of return. The regulator can take a close look at forecasts and turnouts for the previous regulatory period to discover significant inflation, which he then tries to claw back in the next price control period.

Question: Has retail competition been worth it in your country? And as we in the U.S. go forward, what is the most important thing that we should do, based on your experience?

First Response: I think it is worth it in New Zealand. We have seen efficiencies and benefits, mainly to the large customers at this stage. The most important thing is to separate line and energy businesses. And make sure they don't hold on to any of the costs that they have inherited or allocated from the energy businesses, so others have a chance to come in.

Second Response: It is too early to say whether it has been worth it in the UK There hasn't been great political pressure for small consumers to have choice. If it proves to be worth it, it will be so only in the long run as far as small consumers are concerned. I agree that the most important thing to do is entirely separate the retailing function from the local wires business.

Third Response: In terms of Sweden, I would say it is definitely worth it for large and medium-sized customers. I'm not sure it's worth it for the very small ones unless you have a very efficient system for meter reading. The most important thing to do is to look at barriers to entry. For example, the balance market is lower-cost for large actors.

Fourth Response: What I've seen in Spain is that it's more important to have a wholesale market working well. What is important is what not to do, that is, subsidize a retail market. Retail is probably not worth it. Allowing new agents to be aware of what is happening in the electric market is very important.

Question: What has been your experience of expansion of the transmission grid? Have you had the U.S. problem of split jurisdiction between federal and state regulators, and has there been a link between the transition to competition and reliability problems?

First Response: Relying on independent companies investing in the transmission network would be very daring. I think incentives for a private company are very limited. In Scandinavia, investments in transmission capacity have to be done by the transmission system operator based on a traditional cost-benefit analysis, like other infrastructure investments.

Second Response: Interestingly, we have no debate in Britain about merchant transmission and new companies coming in. We have a significant volume of transmission investment, mostly reinforcement of old transmission capacity for reliability type reasons.

Third Response: The New Zealand transmission system is very problematic. The industry has set up a grid security committee to appoint a common quality coordinator who will be issued a set of standards for reliability and security of supply, who will then go to quality providers, generators and distributors, and negotiate until all parties are happy. It's not a regulated system. The objective is to get a consensus.

Fourth Response: Spain had an excellent network, and we have had only limited problems. That has created the idea of an incentive expansion network that is completely regulated and planned by the transmission operator. The only problem is the connection with France, which didn’t introduce a wholesale market, so you don't know the price, then you don't know that we have a problem because you don't see the price to the other side of the border.

Question: Do you expect innovative

services to develop, and if so, do you think that's the important part of this? Are savings on electricity necessary as a precursor?

First Response: One of the benefits of competition is that it's the customer who decides what kind of services they want. And right now, they want low price, advice about hedging, administration and billing that works. I think in five years, they're going to outsource a lot of their electricity business.

Second Response: In the UK, large consumers nearly always say they're pleased to have choice. They also say that 95 percent of what they're interested in is getting the lowest per kilowatt hour price on a simple tariff basis with no frills. There have been a few innovative services offered to large consumers, but I'm not sure if they're a consequence of competition or whether it would have happened anyway because these companies have an inherent interest in better managing their electricity purchases. In the small consumer market, undoubtedly it's entirely going to be price-based. Our government in Britain and other European Union governments do worry about the Kyoto Protocol and meeting what may or may not become legal commitments to reduce greenhouse gas emissions. It was thought that the introduction of half-hourly meters in the small consumer market might be the vehicle for new kinds of efficiency-based services, some subsidized, some market-based. But because we have a profiling system and no way of making efficiency pay, I don't think we can see a development of those kinds of services in the small consumer market. We'll have to meet our Kyoto commitments some other way. So the overall conclusion is fairly negative as far as services other than simply price reductions.

Session Three: Retail Markets Over Here: Are They Contestable, and Contested?

Many of the issues in U.S. retail markets are similar to those of retail markets elsewhere. The results in the American states that have opened up to competition in the supply of electricity have been mixed. In some states, most notably Pennsylvania, the competition has been fairly robust. In other states, such as California, Massachusetts, and Maine, competitors have not entered, or entered and soon left, the market. What are the reasons for the mixed results? Are the margins in retail supply too small for there to be real competition? Have shopping credits in states such as Pennsylvania been elevated to levels that provide inefficient subsidies to new entrants? Conversely, has the desire to show instantaneous rate reductions to consumers led to the establishment of arbitrarily low rates for default providers? Do incumbents have too many built-in advantages when they are the default provider? What advantages and disadvantages are possessed by the incumbents; which by the new entrants? Should incumbents be allowed to be the default provider? If the incumbent is not the default provider, then how should one be selected? Is consumer lethargy among small users too profound to be easily overcome? Who should do billing and metering? How much of the distribution function should be unbundled?

Speaker One

In many states, less than two percent of customers have switched, and even in Pennsylvania, which deliberately chose to set the backout credit higher than the utilities' actual cost, only 10 to 12 percent have switched.

Why? I think the two most important reasons go to the conflicting goals that we are trying to achieve in the design of our transition programs and the underlying economics of commodity retailing. There is a conflict between efforts that states have taken to try to keep the default supply or standard offer service as low as possible, and to offer that at a hedged price. Two features of retailing are important: The cost of and ability to hedge the commodity; and transaction costs.

There are four widely recognized problems with serving small customers: Small volumes, thin margins, high transaction costs relative to those margins, and the difficulty for a new entrant to offer value-added price hedging services because the price of default supply is already hedged.

If you take an average commodity bill for an average residential customer of about $30 a month and put a typical retail margin of about 5 percent on that, you're looking at $1.50 a month in the margin. Margins are squeezed because the price of default supply has been made as low as possible in many states, but even competition itself will drive these margins down once the retailers are going against each other.

There are two categories of transaction costs. One is back office. The more important category for new entrants, though, are sales and marketing costs. You have to do something to contact customers and persuade them to buy from you and not from somebody else. Incumbent utilities have two advantages relative to new entrants. One, they have scope economies in the back office. Given that they already sell delivery services at retail, the incremental back office costs from also passing through the commodity price are very low, literally printing another line on the bill. Two, as a default provider passing through the spot market, there's no need to invest in customer acquisition costs, which is the major cost driver for new entrants.

Big customers will switch for a much smaller price discount than small customers. Not only are they sensitive to price reductions, but it's easier to deliver a bottom line bill impact to a large customer because so much more of the bill for an industrial customer is generation-related.

There are two points of view about the fact that few customers are switching. One is that if you remove the barriers to switching and customers don't switch, then you have success by definition. In particular, if the price they're paying is the unhedged wholesale spot market price, they're saying that there's not enough value to make it worth their while to pay the price they would have to for retailers to cover their costs. The opposing view is that not switching is a problem.

The problem with separating the commodity business from the energy delivery business is that the cost impacts on the average residential customer could be 10 to 20 percent. Marketers say it's around $50, $70, $100 to get a customer to switch. New entrants say they need to back the retailing costs out of the utilities' cost structure, otherwise customers who switch will have to pay for these costs twice. Well, the reason they have to pay for them twice is because the costs are incurred twice.

Another thing that's misunderstood is what you can save if you have the ESCOs do things like issue a combined delivery and commodity bill. What really affects the ability to drive some of these costs over to the unregulated side is volumetric billing for delivery services. As long as the utility bills for delivery that way, a lot of data has to be stored. And utilities don't have incentive costs, that is, don't pay customers $50 a head to sign up for delivery service.

Maine recently conducted an auction and rejected bids for two of the three utilities because they were too high. GPU put out default supply for bid, and nobody bid to serve them. Texas is separating their retailing functions completely from their wires, and is spending tens of millions of dollars to duplicate this back office capability.

There is a consensus that the key is how to design default service. I continue to believe that the default supply ought to be the wholesale spot market price for electricity. It's what will actually happen in the physical market, so it's a great benchmark by which customers can evaluate a price hedge. And you want to have some load response on spot prices if you want to have a well-functioning wholesale market.

A major concern about this model is whether prices will be too volatile for customers to stand. Looking at a small customer consuming 250 kilowatt hours, the effect is in the $10 range. But for a typical large industrial bill, an $80,000 swing on a monthly electricity bill will cause tension. Once the CTC is paid off, industrial customers are going to be buying a lot of generation, and they are the ones I would expect would be more interested in price hedging.

The problems you have if you continue to make this hedged amount to having to extend regulation into the market in a lot of complicated ways, which is, in part, how we got into this mess in the first place. I continue to believe that among the choices available to retail customers should be buying wholesale at the low administrative cost that the utility can offer. It's not a good idea to impose a structural change whose immediate impact could be so enormous on average residential customers without any real market evidence that value is being created.

The problems of billing are widely misunderstood. People are confusing outsourcing with having retailers issue a combined bill. They're not the same thing. One will raise costs, the other might or might not lower costs. In New York, customers say they won't switch if they have to pay two bills. That is a symptom of a much larger problem, because what customers are saying is there's not enough value to make it worth their while to write out a second check.

Speaker Two

Retail competition is an option customers should have. But smaller customers especially should have the option of buying at wholesale through the UDC, and that's the option that retailers should be competing against. If they can provide value-added compared to a wholesale offering, that's great. If they can't, they won't get customers and that will be the end of it.

What do retailers in other industries provide? The most obvious is convenient locations, convenient times of operation, and other services that make shopping convenient. That’s why stores open 24 hours a day are called convenience stores. Department stores are successful because they provide a range of products in a single location and deep inventories with different sizes. Stores provide point-of-sales services, personnel who can show you how things work. Retailers have found new and cheaper ways of providing services, and they can pass on the benefits in lower prices to consumers. A lot of the activity that retailers engage in are credit arrangements, billing arrangements and other types of ancillary services that make it possible for customers to shop.

This goes for the new economy, too. AOL, for example, provides wide distribution and easy installation of software; it's very easy to use AOL to get connected to its services as well as to the internet; and it has product innovations like easy-to-access chat rooms and instant messenger service.

Applying standard retailing lessons to electricity, you confront challenges because of some of the attributes of electricity. Convenient locations and shopping times aren’t a service that could be provided to you by a retailer. Multiple brands and complementary products—electricity is basically one homogeneous product. And it's important to distinguish between the mass market and the industrial/commercial market in terms of customer care responsibilities and the relative costs of advanced metering, communications and control equipment, and concerns about consumer protection. The opportunities to provide economical value-added services are much lower for small customers than for larger.

So where does the potential value-added lie in electricity and why should we be interested in having retailers compete? One area is to reduce the cost of retailing electricity through innovative sales and billing arrangements, and we've seen the development of internet billing and sales. The challenge is that UDC retailing costs are presently quite low relative to the total costs of a customer's bill, especially for the large customer segment relative to their consumption. There is little advertising in the typical UDC's cost structure.

Another area is superior wholesale power procurement to offer lower prices. The challenge is that if you have good wholesale markets, aside from providing hedging services, providing lower price services is going to be challenging. On the other hand, if the wholesale markets are functioning poorly, retailers can help the wholesale market improve its performance.

Installation of sophisticated metering, communications and control equipment is another area of value-added service. There is hedging market risk, including weather-related impacts, but unless you put in interval metering for customers that are billed on low profiles and have their bills read once a month, the opportunity for providing those products is substantially reduced. There are enormous value-added services for larger customers in the area of inside-the-fence services, such as a university that consumes enormous amounts of electricity, purchases natural gas for its co-generator and for heating, etc., and could probably save a tremendous amount of money. Finally is the option of selling to consumers the opportunity to pay more for power sources that are environmentally benign.

There is a social value to a successful retail market. The retail and wholesale markets are not completely separate. Some of the problems in wholesale markets have been the result of the absence of price-responsive retail load, and the only way to get that into the market is to have an intermediary offer price-responsive contracts to retail customers. You don't need a lot of demand elasticity; you can dampen some of the excess disequilibrium with as little as 10 to 20 percent of the load that's price-sensitive on a day-ahead basis. And retailers make for a more competitive and liquid market, which benefits everybody.

Why are retailers in the mass market having so much difficulty? Price discounts are modest. The median U.S. residential customer only consumes $20 to $25 a month worth of wholesale generation costs once you strip the stranded cost. And of the states that haven't done any restructuring, many have no stranded costs, so there isn't that to play with in terms of providing some margin for retailers without increasing rates immediately. There's a limited set of economical value-added services. Customers want an accurate bill in a timely manner. I already get that. Advertising and marketing are costly. Good back-office billing and settlements operations are challenging and costly to create. Successful internet retailers have customer support services that make it possible for customers to get in touch with them quickly with questions before and after they buy. The price to beat has included little in the way of customer service costs. If you sell on the internet, you are screening out a lot of customers who don't have computers or credit cards. A retailing system that excludes those customers *de facto* is not going to be accepted from a public policy perspective.

Is retail competition a success or a failure? In Pennsylvania, a lot of larger customers switched quickly and are being offered price discounts and some value-added services. For residential, a non-trivial number have switched. But switching has ground to a virtual halt due to rising wholesale market prices which are making the shopping credits look smaller, and the structure of the shopping credits, which decline rather than increase over time. In California, a non-trivial fraction of large customers have switched. Few smaller customers have switched, as there are more value-added services to provide to the larger customers. In Massachusetts, very few residential customers have switched, but a non-trivial fraction of large customers have. So I don't think we should view it as a failure.

So what can be done? Retailers should be encouraged to compete against the wholesale market option that should be made available, at least for an interim period of time, to smaller customers. If they can't provide value-added services against buying directly at wholesale, that's life; they'll have to focus on the larger customer market until they can come up with value-added services. The way to make it possible for them to compete fairly is to unbundle the T&D costs, stranded cost charges, and customer care costs that are inevitably going to be incurred by the UDC. The UDC should be required to offer basic energy service—they buy directly in the wholesale market and pass on the wholesale market price to customers, including losses. I would restrict the ability of UDCs to provide a hedging product and other value-added services to retail customers beyond this; that is a function for competitive retailers.

Customer service costs need to be rebalanced to reflect cost causality. There's too much on the kilowatt-hour charges and too little in the customer charges. The UDC should be required to offer optional metering and billing services. It should also present more information to customers about the availability of services from the ESCO.

Speaker Three

We don’t want to replace the old, single legitimate model with some new, single legitimate model that's overly structured and overly regulated. That is one of the traps that we can fall into if we're not careful.

What is the role for new entrants in helping to create new models? The new players are taking on some of the risks that utilities were no longer willing to take on, such as hedging risks. Retailers are guiding customers in the exercise of choice. This has always been done in different industries—retailers do a lot of the thinking for customers that they don't want to do for themselves. We are identifying a lot of inefficiencies in the wholesale markets and in the legacy billing systems of utilities. In some cases, the customers were aware of the problems but couldn't get the company to listen to them or to fix the problems. We go out and fight on behalf of a dozen customers at a time. If we don't keep regulators and utilities focused on change, there's going to be a lot of backsliding.

The two key barriers to competitive marketer entry are standard offer default service and the lack of adequate shopping credits. What standard offer or default service does is tempt us to hang onto the past. We're going to try to regulate it and oversee it in much the same way that we did bundled service. It creates a kind of safety net which tends to stunt the market. The government or a quasi-governmental body sitting there with a product that's ready to come onto the market or accessible to you anytime you don't like what's going on in the competitive market tends to undermine the willingness of new players to commit resources or effort to a new market. And it tends to give a kind of split personality to the utility—it takes a new role for them, offering standard offer service apart from their bundled service, and puts them in a no-man's land between being a delivery company and being a full-service provider. It keeps regulators in the business of trying to set prices. And it can create new stranded costs, because there will be a lot of fooling around with standard offer prices and there may be a tendency to defer collection of these full costs.

The other major barrier is the lack of adequate shopping credits. The question of the shopping credit is whether, once the transition charge has been established to collect stranded costs, a customer who switches is given a discount of some kind on that stranded cost collection charge. If you have that discount to the CTC, which is the shopping credit applied across the board, to those customers who switch and those who don't, we're at the outset deciding not to make the trip that we've embarked on.

The other thing that the shopping credit does, again if we think of it in terms of a discount to the stranded costs or lost revenue collection charge, is create competition among marketers to deliver as much of that discount as possible to the customers. If we don't have these near-term opportunities for savings through a shopping credit, will we be able to get new entrants into the market who then will have an opportunity to create new services? None of us really know now what those opportunities are, and they are unlikely to be produced, at least in the near term, if new entrants are not brought into the market by the opportunity to compete with other new entrants.

It is true that there is an inverse relationship between the size of the customer and what's required to get that customer to switch. We did an analysis that looked at our customers between the 25 kW and the over 1 MW demand level. Customers over 3 MW have an individually calculated transition charge. So just by switching, you get an eight percent or half-penny per kWh savings, whichever is greater. So the job of the marketer is to deliver some increment on that. At the lower levels of customers, there's an average eight percent reduction. But if you have a lousy load factor you tend to get a larger reduction, because the CTC is collected volumetrically. The competition among the marketers was to deliver as much as you could to these customers and find the customers who could get the most. So I would expect much lower switching rates if we were limited in what we had been able to deliver.

Among customers between 100 and 400 kW of demand, the savings are clustered in the middle, but there is diversity. Some customers are making switches in the one to five percent level. But when you get up into the eight to 10 percent level, you begin to get movement even in that area. So it's highly unlikely that, if you're unable in the commodity side of the business, in the initial stages, to deliver the savings to customers, there will be any switching to speak of. The lack of switching means that new entrants will not be coming into the market, at least for some time. Thus we won't see innovations in the system.

Speaker Four

What do we expect from retail competition? We expect lower energy costs. We expect expanded energy service options. We expect development of new technology and products. We haven't seen a lot of that yet. Another thing we ought to get is lower prices overall. In fact, in looking at the de-regulation of inter-city transportation, one study has found quite significant savings in railroad, airlines and trucking. Once deregulated, the airlines went to hub-and-spoke systems, came up with multiple pricing models to attract customers, did more supply-and-demand work. In trucking, we saw the advent of satellite devices put on trucks so that the status of the truck at all times was known. Railroads went to much more customer-specific pricing as well as coming up with innovations in how they kept track of the trains, electronic scanning and what was done with double-stacking on cars. Simple thesis: If deregulation of energy is to produce the kinds of savings we've seen in these other industries, it's going to have to be through the development of a retail market.

We're getting much more active, competitive wholesale markets. But the wholesale market is simply providing the fodder for retail products and services. It is not providing the reduction in overall system price. It's not improving system reliability.

The right price for retailers to compete with is the wholesale price. In fact, this is not the price the customers see. Customers now, through default utility service, are receiving a financial product in the form of a lagged, smooth price.

What is leading to this demand result? Looking at the total demand curve for a peak summer day, we all know that air conditioning is one of the major contributors, but people are drying their clothes in electric dryers at peak. If people were receiving an actual real-time price of $250 a megawatt hour, do you think they'd be drying their clothes at that point? I don't. They are using dishwashers, washing machines, pool pumps, hair dryers. A two degree change in the thermostat setting will have a significant impact in the amount of use. A study done, I believe by EPRI, pointed out that 95 percent of the population doesn't notice a two degree change.

Can we make that happen? I found this web site the other day, www.aladdin.com. They manufacture a power line carrier technology that allows you to make your appliances smart and operate them remotely. A utility can adjust customers' thermostats remotely in order to deal with the time of peak. This is the kind of technology that, if customers were looking at real-time prices, there would be a demand for, and significant customer savings would be possible. Utility investments in demand-side management programs are greater than for us to get the metering in place to allow these prices to be seen.

What are retailers going to provide? Customized rates and services, DSM products and services, aggregation services. The Ohio "Apples to Apples" program is, I think, the best example in the country of how to do retail correctly. It gives customers at a look at what the local utility charges, the default supply, and what is in the market. That is a pricing choice. Essential.com is looking at providing electricity, energy services, green power and gas. We're enabling a retailer to simplify people's lives. They add electricity to a market basket of goods.

A British study concluded that hourly interval meters would improve system planning by providing a better indication of where demands are on the system, help save energy and cut prices through price responses, reduce power costs at the peak, eliminate estimated meter readings and provide better outage response. Hourly meters would instantaneously let us know about an outage. It also instantaneously tells us about fraud. Unlike with a customer calling to report an outage, you would know right away whether an outage is that customer, or everybody on the block, or everybody in the city. And finally the study concluded you would enable a wide range of payment methods and tariffs. Hourly meters are a critical piece of the enablement of retail markets.

Governor Engler of Michigan commented that we need to offer choice to those who want it, but protection for those who need it. There is going to be a continuing need to deal with people who aren't prepared to cope with the full wholesale price. We need to make sure that the segment of the population that is housebound, that needs to keep the air conditioning on, that needs basic supplies, is not disadvantaged as we go forward. But I think we can do that through the kinds of programs that we use today.

I conclude that wholesale only gets you partway there. To develop the full benefits of deregulation, we need to enable this retail market. It will provide us the kind of benefits that we've seen in other industries that I maintain we are not seeing today. California has done a good job of revealing wholesale price. The fact that we've created a competitive wholesale market is not, in and of itself, reducing prices. It's going to be the response to that market—a response that I believe retail will provide—that will create the benefits that we want.

Discussion

Question: Has aggregation entered into your thinking?

Response: Aggregation definitely has a role to play. It can help with the customer contact piece of the problem that retailers have. But you still have to give customers a reason to buy from you. And that's difficult to solve.

Question: In terms of metering, isn't it a Catch-22 in that you can't get implementation until the price drops, but won't save until you have it?

First Response: The best way of testing out these technologies and finding out what metering can do is to give customers an opportunity to choose whether or not they want them. Also, we don't know yet what the value is of the information flow between the customer and the provider, and we're only going to find out when there's enough freedom to experiment, and we're unlikely to get these experiments through a central planning approach that requires utilities to do things or tells them how.

Second Response: The dilemma is separating the mass market from the larger customers. The savings are from economies of scale. In the small customer market, where you're feeding off the low-voltage distribution grid, most of these attractive numbers come from deploying them very intensively within a particular geographic area.

Question: If we have a default or basic electric service, would it make sense to separate the retailing function from the transmission and distribution utility, so that you have affiliated companies with codes of conduct?

Response: If we could achieve that separation with no net increase in cost, I would advocate that. The problem is the notion that we ought to force a structural change whose immediate impact would be on the order of 10 to 20 percent for the average residential customer, and justify that on benefits that can't be quantified, in some cases can't be identified. I don't see why passing through the spot market poses any barrier to product innovation.

Question: If we implement a default or basic electric service that passes through the wholesale spot price, those prices are highly volatile, and a preponderance of poor or low-income customers chooses not to switch, what are we going to tell the elected officials the first time customers see their prices up 40 percent?

First Response: That is a risk, but for small customers, the impact on their bill is small. After running bills, my thinking has flip-flopped in terms of which customers I think are going to be most interested in price hedging—it makes a much bigger difference for the larger ones.

Second Response: A typical residential customer being billed on a monthly basis doesn't see the spikes; they get averaged out over 725 hours during the month. I don't think you're going to see huge jumps in prices. If people don't want to be faced with a competitive market, I guess the answer to the legislators is maybe you shouldn't have voted for competition. I also think it's important to distinguish between low-income customers and small customers. In Massachusetts, less than eight percent of the customers qualify for low-income service, but small customers are the mass market.

Question: Switching has slowed down and is maybe even reversing in

Pennsylvania. Forward electric prices have gone well above the backout credit, and most suppliers are dumping their customers with an invitation to come back in September. Are there models, preferably from outside of electricity, of default service or provider of last resort that can protect widows and orphans from volatile prices, and yet that won't cause the collapse of a market structure?

First Response: Widows and orphans, you need to subsidize. You don't want to mess up the whole market because you need to protect a small group of the population from the market. It would be better to identify those needy customers than to distort the market to protect them.

Second Response: Is anybody surprised that we didn't get everything right the first time through? The question is whether we have the capacity to revisit things. Where we do run into problems is when we overdo it. We made the rules too complicated. One of the key drags on making this transition is this notion of developing a highly regulated, additional default product that the utility provides. Let the utility provide bundled service, and let the new marketers provide whatever new services there might be.

Third Response: The approach that's been taken in Pennsylvania is a two-edged sword because, while there's a fairly large shopping credit, the other side of the story is that every time a customer switches to a retailer provider, the utility is losing money. I don't think retail competition is going to go forward very quickly or well if utilities hate it. There has to be an approach where the utilities are enablers of the market. I prefer the California approach because the utility is indifferent to the customer switching to a retailer; it isn't losing money. In fact, they have an incentive to treat the retailer as a new customer class.

Question: There is an assumption that the retail market will foster new technology and innovative solutions. Is electricity different than telecomm? Where is the next call waiting or voice mail?

First Response: Natural gas is a better analogy to electricity. The potential is in control technology and communication technology, with the possibility of reducing energy prices. But there's a real question whether the infrastructure costs might mean the benefits are never there for mass market customers.

Second Response: A competitive market will be about how to use electricity more efficiently and at the right times. A device on my washing machine that won't run it if the price in the pool is over 10 cents a kWh would also allow me, while I'm at work, to turn it on via the internet. Once you get the technology to help you respond to price and to control appliances in a different way, there will be ancillary effects that change the way you do things.

Question: Metering can probably be done. But is the wholesale market ready for us to pass it through to default customers? What kinds of transition mechanisms would one think about if there were concerns about how the market is functioning in the near term?

First Response: One of the benefits of passing the prices through would be to get more engagement from consumer groups and regulators in the region to work to fix the problems in the wholesale market. In New England, transition arrangements will be needed. We're not doing anyone a service by hiding the costs that are emerging in the wholesale market.

Second Response: It's already being done in New York. The big customers screaming about the problems is helping focus everybody's attention on fixing them.

Comment: We should discuss the notion of backing out certain double-counting.

First Response: Backout credits ought to reflect the cost that we save by not providing that service. There should be some credit for back office costs, but they are nowhere near what it costs a new retailer to build from scratch, and it certainly doesn't include the kinds of incentive costs you have to pay to get a customer to sign up with you.

Second Response: If I sign on for utility.com and take an internet billing option and Boston Edison doesn't have to send me a bill anymore, they're saving the cost of the envelope and stamp, some bad debt costs. All that ought to be credited. But if utility.com bills me on the internet for the energy portion of my bill, and I still get a bill from Boston Edison for the other charges on my bill, there isn't any cost saving and I don't see why there should be any credit.

Comment: New Jersey is the new Pennsylvania. It has bundled rates with increasing shopping credits, and customers are switching back because there is a mismatch between the market price and the value. It's going to drive failure of innovation because we are not staying with the market price and asking, How am I going to be smart about getting creative demand bidding options and managing against that wholesale price? Utilities are a different animal than they used to be; they're delivery companies. It's how you characterize the transition; we need to realize what pieces are part of the transition and what pieces aren't. We have too many pieces masked and are putting the lid on everything because of the model we've gone with.