

**Harvard Electricity Policy Group
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RAPPORTEUR'S SUMMARY*

Morning Session: Regional Transmission Organizations

The long-awaited submissions to the FERC announce the next stage in the transition to regional markets under open access to the transmission system. The international debate has produced alternative models in theory, and we now have more experience in practice. The regional proposals reflect this debate and the challenges ahead to craft workable systems that involve so many participants and so much history. The practical experience is accumulating to show the importance of market design and the problems of integrating such a design with the operational requirements of the transmission grid. This session will explore the alternative judgments on these matters in the proposed RTO plans, timing and coherence. What are the models now proposed? How do they differ from each other and from the systems in operation? How will seams issues be addressed? What are the prospects of moving more rapidly to implement the proposals before changes in supply, demand and market conditions make everything harder rather than easier?

Speaker One

I am going to discuss RTO West. In terms of some of the challenges we face that differ from other RTOs, one of the largest differences is the

transmission price differentials. We have extremes, from Idaho Power in the \$6 range, to Montana Power in the \$50-plus range, with the other participants scattered throughout the middle of that range. That creates a

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significant challenge to ensure that any pricing proposals do not cause significant cost shifts among the utilities participating in the formation of the RTO.

Another big difference in our region is the domination of the Bonneville Power Administration. Everyone is dependent on Bonneville, and it is critical that it participate in the RTO. The challenge is for us to work through proposals that do not jeopardize their statutory obligations.

An additional challenge is the low-cost power our region has--a lot of hydro and coal. The utilities want to make sure it remains low-cost. Then we have our neighbor, California, which is part of a larger Western market, and the events there are having impacts across the entire West.

We have challenges with retail access because we cover so many states. Oregon is proceeding with the implementation of Senate Bill 1149. That will be up and running in advance of the RTO being operational and will create its own complexities in terms of making sure it runs well with the RTO structures that go in place. Wyoming and Utah are taking some actions towards pursuing retail access in their states on their own time frames and each differently.

Another challenge is history and baggage. In the West, we tried this once before with INDEGO. That effort failed, primarily because of cost-

shifting and the inability to come to conclusion on a pricing solution that would mitigate the amount of cost-shifting in the region. We also believe that that effort did not have serious commitment from all of the participants.

There is the debate over whether it should be a transco or an ISO. We are proposing an ISO that will be a non-profit, state-chartered corporation. It will not own assets. It will be governed by an independent board of directors, and this is where we differ. We went beyond Order 2000's requirements for independence. We have a stakeholder advisory committee that does not have direct influence or power over the board of directors. RTO West will not be able to operate a power exchange.

We also differ in our geographic scope. We involve the entire Northwest Power Pool, plus Nevada Power. We have two major paths into the Southwest, and have had extensive involvement from Canada. We cover an extensive number of states--Washington, Oregon, Idaho, part of Montana, part of Wyoming, Utah, Nevada and, hopefully, Canada. Within that geographic region, we have over 15 control areas, which we will be consolidating into a single control area operated by RTO West.

Pricing is another area where our proposal differs from others. We have come up with a pricing structure that manages the cost-shifting problems in

our region. It is a company rate proposal, and will be in place for 10 years, starting December 15, 2001. It will be load-based. There are also a lot of long-term transmission agreements between participants, as well as short-term firm and non-firm. We need to ensure that does not create a cost shift as well. We will be handling that through a mechanism referred to as transfer charges. Those transfer charges will result through a negotiation process in our next phase, and will be based on historical levels.

Our proposal also differs in that it has no export fees, assuming reciprocity at the seams. We have the seam with California and with DesertStar. California ISO and DesertStar currently have exports as part of their proposals at FERC.

We have identified criteria in which facilities will be tested to determine whether or not they're required to be in the RTO, and the RTO will have full control over those required facilities, planning as well as operating. We've provided eligible customers with a one-stop shop through the RTO for access. As retail access continues in our different states, states define eligible customers differently. They are not always connected at the high-voltage system. We want those customers to be able to take their service from the RTO no matter what facilities they are physically attached to. We have a set of facilities that fall in the middle, between the distribution and the required facilities. They will

remain with the transmission owner from an operational control and a planning aspect. The RTO will have planning oversight over them. The RTO or transmission owner can have a separate tariff for those facilities or can include them in the tariff along with their main grid facilities.

We also differ on congestion management. Ours is a hybrid proposal, a combination of the flow-based approach and the physical rights model. Part of the work to be done is defining the congestion zones and how many there should be. Our proposal has the RTO establishing the total transfer capacity for those flow paths, then firm transmission rights will be issued--so FTRs will be required when scheduling across a congested path.

On transmission rights, we have filed an agreement to suspend all pre-existing contracts; we will be issued the FTRs for the suspension of those contracts. FTRs will also be issued for load-serving obligations not covered under those suspended contracts. And there are provisions that cover load growth, as there are some concerns about that in a few areas within our region, Utah and Oregon/southern Washington. Unscheduled FTRs will be made available in auctions as either recallable or non-firm transmission rights.

In the area of planning and expansion, the RTO will be responsible for the operational planning of all those facilities under its control. It will also

do long-range planning, looking at the total grid. Nothing in our filing changes the states' authority. The RTO is responsible for reliability, but we have put obligations on the transmission owners to make sure the transfer capacity of those facilities stays at that level. We've also given the RTO the ability, when requested, to allocate costs for reliability expansion or changes to the benefiting loads.

We believe congestion should be dealt with by those who benefit from congestion expansion or the release of congestion. Interregional coordination activities are gaining strength. The Western Market Interface Committee is forming a task force that involves all three RTOs in the West. It will operate as a coordination group and develop proposals to deal with seams.

RTOs are not the whole solution to supply/demand and market issues. We also need to deal with simplification of siting processes. We have to get more supply available in a timely fashion. We need concentrated efforts on conservation throughout the country. We need for California to stabilize.

Speaker Two

The critical issue for RTOs is the structure of the market design and how you deal with certain problems, most importantly the short-run coordination problems and their interaction with some long-term rights. If you get that part of the story right, everything else

is a lot easier. Happily, Order 2000, I think, gets the story right. The centerpiece is the coordinated spot market, bid-based, security-constrained, economic dispatch, with nodal prices and bilateral schedules, financial transmission rights, which go under different names in different places, but the right to collect congestion rents, market-driven investments, license plate access charges, and so on.

I was quite pleased with Order 2000. But there are two big ifs: If FERC means what it says and if FERC follows through. This market framework is not, at this stage, a pie-in-the-sky idea. The basic structure exist in various places around the world. We know a lot about it and about what works and what doesn't work. The essential elements of that market design are the pieces of the puzzle that have to fit together: The congestion management system, the balancing rules, how you organize transmission usage, and how you decide on provision of and coordination of ancillary services, reactive power, and all those kinds of things. It's not possible to have a conversation about one without having a conversation about the other. They're different parts of the same puzzle.

What I read in the various RTO proposals is that on the critical issues, they are sketchy, they didn't lay out all the details, a fair amount of mumbling went on, trying to pass off the problem

to someone else, such as a future organization. On the details of things like congestion management, balancing, ancillary services and so forth, the pieces don't seem to fit together. In some cases they're internally contradictory or they don't talk about how the elements fit together. So it's a conversation that is in progress, but far from a sensible resolution.

You do see a lot of flag waving about, we're going to have a Transco, or we're not going to have a Transco. This is, in my judgment, a third or fourth level issue. As long as you do the other stuff right, it doesn't matter. It is clear evidence of a deep debate about this issue, where people fundamentally disagree. You see the characterization of alternative approaches to how we're going to manage congestion in the system, and one thing that is clear is that we have run out of new ideas.

In these RTO proposals, you see debates that are familiar to us all. The two principle ones are: Well, I don't like this bid-based security-constrained economic dispatch with locational pricing, anything but that. People try to avoid that, and one way is, well, maybe we could just aggregate everything into a few congestion zones because the places don't differ very much. The other argument is the flowgate model, which is related--well, there are just a few interfaces between these big zones and we can identify the flows across those flowgates, and if we had just a few of

those, everything would be simpler.

My position is, when you look closely at these things, they're just not true. The arguments in favor of congestion zones and the flowgate models are approximately correct. But they don't tell us anything about what you need to do with the RTO, which is a separate issue. So these arguments in favor of these simplified approaches carry the seeds of the answer, which is that if the world is as simple as you say, the RTO doesn't need to do this, the market can. If not, it better do something else.

As far as the California situation, FERC has seriously dropped the ball on its order. The things FERC proposed are tepid and ineffectual. Then it says, please appoint somebody else, this new independent board, and have them fix it. This is not going to solve any of the difficulties. Much more is needed, and FERC is going to have to do something quite different. The staff of the Federal Trade Commission, in their comments on FERC's California proposals, say that FERC ought to say more, perhaps have benchmarks and be specific about what ought to be done. I don't think the FTC staff goes nearly far enough, and we have to face the fact that FERC is not now providing what we need.

The California design is seriously, fundamentally flawed. The California market has unique features that no one else in the world has tried. They have been demonstrated not to work in

theory, and now experience demonstrates that they don't work in practice. The market design has to be fixed. It's not the emergency part of the problem, but it's so entangled with everything that's happening right now that it is almost impossible to figure out what's causing what, because the design is such a mess.

So when I come back to the general question about RTO developments and alternative market models and the experience in California, and put these all together, the simple stories don't work. Congestion zones either don't matter or don't work, so if you really could aggregate into regions that were the same, you wouldn't have to because they would be the same already. The same is true for these flowgate models. The critical thing is how you do real-time balancing, not how you do the long-term forward market part, and that's what we have to get right, but people are trying to avert their eyes from that problem because it's where all of the hard work is.

RTOs can help tremendously. But it's the two big ifs--if FERC means what it says and if FERC follows through. So far, most of the RTO proposals are placebos, and they're not going to cure this disease. But we know how to solve this problem, and that is a set of orders that is consistent with Order 2000 and that has been implemented in various parts of the country and the world, and we know that it works.

Are we following through on the order

or is it falling apart? California's going up in flames. In the Northeast, we know more or less what to do. And in the middle of the country, where time is running out, the sands are falling through. We're still debating old issues. I fully endorse Bill Massey's statement in a recent speech that we know what to do and we should just do it. But in the California order, FERC ducked. Everybody can't duck or California really is going to go up in flames and take the rest of the country with them.

Speaker Three

GridSouth Transco is an RTO proposal formed by Duke Energy, Carolina Power & Light Co., and South Carolina Electric & Gas. It will cover the entire Carolinas except for Santee Cooper, which is a state entity, and which we're trying to bring in. The three companies all wanted to form a joint venture transmission company that would operate on a for-profit basis, but they also realized that the Carolina states are not ready for restructuring. So transmission divestiture was not an option. The solution was to create a for-profit limited liability company that will begin as a transmission operator and later acquire transmission assets. GridSouth will be about the same size, in terms of load served, as the New York Power Pool, maybe a bit bigger. It is significantly larger than NEPOOL and the same size as California or a bit smaller. It's being proposed as a foundation for a larger regional entity.

The key question is how hard FERC will push the combination.

In terms of the initial wholesale market structure, all of the elements that FERC requires to get an RTO up and running are in place. You will also see a considerable amount of work that was done on creating a for-profit joint venture company. We put in after-the-fact imbalance trading. There is no consolidation of control areas yet and no centralized balancing market.

Within one year after GridSouth becomes operational, it is directed to open a stakeholder process to reform the markets. It is obligated by the documents to consider combining the control areas, creating a centralized balancing market and a congested management regime reflecting locational prices. But the one thing that was insisted upon was that before we go ahead and implement these market reforms, they want to see a cost-benefit analysis.

That gets to the heart of the problem. That is, why did we defer market reform? We couldn't get agreement otherwise, and no agreement, no RTO. There's very little interest in restructuring in the Carolinas. The market design will be done by GridSouth, not by the utilities--that's the right thing to do. And going from the regime and structure we have in the Midwest and Southeast right now to the kind of market design the previous speaker talked about is very expensive. In a region where prices are

well below the national average and new generation is being built, somebody has to justify why we ought to do that. That's a hard case to make right now in the Carolinas, and it has to be made in the future by GridSouth.

Finally, there is a huge debate going on, and we thought there was some benefit in letting things shake out a little bit rather than design a market that would then have to be redesigned.

What are the next steps? GridSouth proponents are working on an incentive rate package to file at FERC. In light of the huge intervention, primarily from the public power sector, a supplemental stakeholder process for a short period of time, limited to discussing the issues in the interventions, is likely to take place. GridSouth would like to form quickly, then seek agreement to combine with others. The final question is, will FERC make the GridSouth participants go back to square one? Whether or not to go forward and get this RTO implemented or whether to slow down is a difficult question.

A provocation: Eight or nine years ago, when we were debating competition, an economist friend of mine was speaking at an energy conference. We were beginning to have open access, primarily for public power, and public power wanted to have delivered surplus power from utilities that were neighbors or down the road, and they were seeking

transmission access so they could "compete." Since all we were competing for was the surplus utilities had, the prices to sell the surplus were far below system average cost. A lot of pro-competition folks said, Isn't this great, competition reduces prices.

This economist was making the point that that was a false signal. That wasn't real competition, that's cream-skimming. He said, If you really believe in electric competition, deregulate when prices are rising and supplies are tight. Then you'll find out whether you really have the stomach for it and whether you really believe in competition. Well, here we are, and we're facing the questions, Do we really have the stomach for it, and do we really believe in it?

Finally, I never in this whole debate saw anyone do a serious analysis of vertical integration in this industry and what the cost of vertical de-integration would be.

Speaker Four

I'm going to take the focus back to congestion management. One of the problems with trying to determine what kind of congestion management system you have in a collaborative effort is, first, there's an education process as to what we mean by flowgates and LMP, what does our system look like, how many flowgates do we have if we were to use a real flow or zonal method and, second, you have to decide what you like.

This past summer at the Southwest Power Pool, there were a number of meetings. First was a congestion management symposium focused on three proposals, LMP, zonal-type, and flowgates. After several further conferences, the regional transmission organization working group, or RTOWG, decided on a hybrid proposal that would include LMP in real time, some type of financial rights in the forward market, and primarily a flowgate model.

Cornerstones for congestion management and real time market design are, first, support for balanced/unbalanced and covered/uncovered schedules that allow load to take full advantage of spot market resources. You can schedule part of your load via a bilateral, but in the real time, there are no penalties if you're out of balance. Second is support for a forward financial rights market. Third, LMP as ex-post based on total demand and actual total generation. Fourth, SPP supports the real time market as an aggregation of bilateral and spot supplies. So if you're doing a bilateral schedule, you have to let the RTO know what it is so that it can incorporate that in the algorithms that maintain system security.

Five, support the RTO's role as a physical coordinator responsible for reliability, scheduling, dispatch, and SPP load forecast. It is anticipated that SPP would be doing a day-ahead load

forecast and would do additional unit commitment if needed. Six, minimize the RTO's need to take a position in the real time energy markets. That means different things to different people, and is a point of contention.

A brief overview of the real time proposal: Market participants can participate by submitting schedules from forward markets, buying or selling in an LMP balancing market, or any combination of the two. The balancing market will use nodal prices for injections and zonal prices for withdrawals, with a nodal option. The system operator will assess congestion charges for schedules based on LMPs at the injection and withdrawal locations. LMP will be calculated across the entire RTO. There will be 17 or 18 control areas in the Southwest Power Pool. The group is working through how to do LMP across the control area without consolidating these. And the SPP RTO will run the markets for ancillary services on an RTO-wide basis.

The LMP market is voluntary; you can submit bilateral schedules, but if you want to optimize against the market you can do so. If you're a load-serving entity and you don't forecast or schedule all of your load moving into the real time, there are no penalties. Generators on bilateral schedules can submit supply curves and optimize against the LMP market. Again, no transmission rights are needed to schedule in the real time. The system operator will use voluntary bids to

optimize the dispatch using the full capability of the grid. Only FTR or FGR holders are hedged against congestion charges; FTRs and FGRs will not be issued in excess of system capability.

The details for the forward market still need to be worked out. The sub-team decided that there will be financial rights and not physical, but hasn't developed any details around the pricing of residual congestion or shift factor freeze dates. One of the most important things is determining what is a commercially significant flowgate and how many you have. This is being worked out.

Discussion

Comment: In response to Speaker Three's comment that this is the best agreement you could get, if FERC had given them much more prescriptive instructions about what needed to be done, the conversation would have been very different. But my concern is that FERC has been, in this matter, not prescriptive enough. On the question of cost-benefit analysis of vertical de-integration, studies were done, but I don't think much of them. It is very difficult to quantify, and the decision about whether to rely principally on regulated, vertically integrated monopolies or to go in the direction of markets is a complex choice, and it depends on which church you belong to. It's a hard call.

But once you decide to restructure, it becomes a lot less difficult because there are some ways that are better and some that are worse. The cost-benefit analysis clearly points in the direction that doing it right, and particularly getting these short-term market operations, is actually the low-cost, simple way to do things. It's not a trade-off. It's not true that the alternative models are simpler and cheaper. They're avoiding reality, and when reality impinges, they become complicated. And it gets expensive and the ISO becomes very intrusive.

Response: My concern is that we never had the right debate, that ideology led to facts. I see two reasons for this. One, there was \$200 billion a year flowing into utility coffers that other people saw a chance to get at. Second, it became a religious thing to do this, and a lot of the arguments got pushed under the table because the people who presented them were viewed as blocking competition. Still, a lot of the problems we're having now are the result of decisions that are independent of how we constructed these markets. California hasn't built any generation; fuel prices are high. These problems are structural in the sense that they were there regardless of whether you had markets.

Comment: It is time for more direction from FERC, maybe even from the national government. Originally I thought that was not a good idea because of the stranded cost issues and

how unique each of the particular state regimes were. But I think we're beyond that now and in a second stage, and it's time to move forward.

Question: In the design of these RTOs, was there a conscious effort to internalize the lessons we have learned in the last three years of ISO operation?

First Response: There is no consensus, that's the problem. Just among the three companies doing GridSouth, and I've seen it in the other RTOs I've worked on, there is strong disagreement about how these markets should be structured.

Second Response: We didn't ignore the other ISOs' experience. Education was the first part of the process. But it's not a cookie cutter.

Third Response: We did make a great attempt to look at what other RTOs or ISOs had done, and I think that largely affected our proposal. But in the collaborative process, each week we have a new member that hasn't been involved in market structure or design, so the training continues. It is a never-ending process.

Question: Coming back to the metaphor of churches, there may be a third school in California that is rising from the ashes: People who believe in markets but feel like they're trapped with bad markets, trapped with a vacuum from the FERC, no leadership there on what is right or wrong, and no consensus anywhere in the country as

to how these markets ought to be coordinated. And does that not then produce a strong reaction to protect consumers by re-regulating on a command and control, almost an emergency basis?

Response: I can think of many things to do that work in the right direction, particularly in California, but nothing that is painless.

Comment: You keep hearing about this \$6 billion transfer of wealth. But we ought to stop and look where it's really going, because it's going all over the place. Put the factors affecting California in the East, and won't the same thing happen?

Question: I saw FERC's attempts to create market monitoring committees as their instrument for distinguishing between legitimate and illegitimate wealth transfers. Obviously, it hasn't worked. Has it failed because the market monitoring committees work so privately or because they have not been able to do that job?

First Response: One, I don't think they've done a very good job. I don't think they've had the resources or time. Two, the warnings they have issued have not been investigated and taken seriously. There's no joining of the issue in trying to figure out what's really going on. Moreover, I believe the California model is opaque and difficult to understand. I think oversight is a lot more possible in a PJM model. Locational pricing helps

to identify the exercise of market power more than zonal pricing, and having sequential ancillary services markets, as opposed to simultaneous clearing markets, makes a difference.

Second Response: There's not a clear distinction between what people believe is monopoly rents and what people think are scarcity rents. And how should the Federal Power Act be interpreted--as arbitrating scarcity rents as well as monopoly rents? Does it take a *per se* violation of the anti-trust laws before FERC steps in, or is there something less?

Third Response: Once you get into scarcity rents, you're going to get into the hard political debate. People are prepared to pay for this. But should they be required to pay for it? Frankly, a lot of people feel that even if they are prepared to pay for it, even if that's what it really costs, they shouldn't have to. But if the provider is not a regulated entity but a private business, how do you make him do that if he doesn't have any legal obligation?

Comment: Just because a state doesn't want to go forward with retail restructuring is not a reason to hold off on going forward with a good RTO. Most of the work in PJM was done before most of those states restructured. It will help wholesale markets work, which helps retail markets work.

Question: Can you explain

decomposing FTRs and making them into flowgate rights?

Response: If flowgate rights are as simple as the proponents claim, there is a very small number of commercially significant flowgates. When proponents say, "We don't need these centralized markets and FTRs, the market is simple if you do it right and just have a few commercially significant flowgates, they can trade them in secondary markets and everything will work fine," I say, "if the assumptions are correct, I agree." The fact that it's not happening is because the assumptions are wrong. There are lots of flowgates, we don't know what they are in advance, and they change all the time; the power transfer factors change all the time depending on conditions in the system. The advantage of the FTR is that it internalizes all of that automatically; the FGRs--the flowgate rights--don't. If you do it the other way, say, We can define a set of flowgates and pay you whatever they're worth, but we're not going to guarantee they'll cover you completely, that is unacceptable because people know they're exposed to a lot of congestion when that happens and they'd rather have point-to-point rights. Point-to-point were developed just because of this.

Question: If you assume the assumptions are correct and this will work, how do you decompose them and how does that compare to optionality?

Response: Suppose there is one commercially significant constraint but the power factors are different for different locations, so you have some impact on the constraint and somebody else has something else. The congestion cost differential would be determined entirely by the different power factors. So we could set up point-to-point FTRs or a flowgate. In both situations you have the problem that I may want to provide counter-flow on that constraint and get credit for it because I'm creating additional capacity. You can have options under the FGR model with a right to use up to capacity, but you don't have to provide the flow--but then you can't get credit for the counter-flow. Or you could provide the counter-flow, which expands the capacity you can sell, but then you have to deliver or take the financial obligation that goes with it. You can define point-to-point FTR or FGR options or obligations, mix and match. You can convert FGRs to FTRs and back. But you can't convert FTRs that will work under any circumstances with LMP to a few simple FGRs with predictable power transfer factors, because that simple model I described isn't true.

Question: Is there a cost-benefit?

Response: In a flowgate model where you get the rights to the flowgate, you get the associated congestion payments that occur in real time. The trouble is that when you propose that, proponents of the flowgate model say, we won't do that. That's the crack in

the system, because when you start socializing these costs, people have a strong incentive to do things that are not consistent with reality because they don't have to absorb the costs. California is a good example. Before prices went up, they proposed a simplified flowgate model. They recognized immediately that that was not going to solve the congestion problem, so they proposed a two-day-ahead market. If you're going to have this stupid design, the ISO is going to have to make it more and more complicated and expensive.

Comment: Everyone says they want to keep the ISO out of the market. And look what's happening. In California, we had the ISO running a real time market and the PX running hour-ahead, hour-out, day-ahead, and ancillary service markets. At some point, reasonable people need to sober up. Businesses and merchants need a well-defined believable market story and market structure--or it's back to closed pool and command and control.

Afternoon Session: State of the Retail Markets

Recent increases in the price of electricity in various parts of the country have led to consumer outrage and political upheavals for electric restructuring. In California, the legislature has imposed a retail price cap, the effect of which is to protect consumers but put distribution utilities at some risk for new stranded costs. Is it déjà vu all over again? In Massachusetts, the distribution companies are seeking to pass through increased energy costs, but are running into opposition based upon consumer expectations that prices could not exceed the rate reductions promised in the state's restructuring legislation. In New Jersey, the ability of the regulators to allow deferred recovery of energy prices above the cap is being challenged in the courts. In Pennsylvania, we have seen a decline in the number of retail marketers and a customer migration back to default suppliers. Load aggregators, whose

participation in the marketplace was anticipated by most advocates of retail competition, have been fewer than hoped. Are we in a crisis mode on the efficacy of retail competition? How will other states, with more recent restructuring or those that are still contemplating restructuring, react? What is the real state of affairs in the states? What steps ought to be taken? What lessons have we learned?

Speaker One

What's wrong with retail is that there are no margins. The people who are trying to sell retail, the Enrons, the NewEnergys, aren't going to make any money at it, in part because we've got legislated price reductions as part of the package in most of the deals. And the start-up and back room costs are huge--back room being accounting, billing, etc. Someone estimated that it costs half a million dollars per service area to enter a new utility service area. And when you think about the margins, particularly in power--let's use a four-cent kw rate, and maybe you'll save 10 percent if you're lucky. That's four-tenths of a cent. You've got to sell a lot of kilowatt hours to make up that \$500,000. And that's before you even talk about the cost of acquiring customers, which is 30 to \$100 per customer. So there's not

much money to be made.

What happened in San Diego is that there wasn't any forward contracting. There weren't any retailers of any significance offering hedged prices to customers. So the customers at the retail level saw the full force and effect of the wholesale price spikes. And then we have the supply/demand imbalances.

In state restructuring, California gave a 10 percent price break, Illinois, five to 20 percent, Maryland, New Jersey, Ohio, Texas, everybody's got price reductions, which makes it hard for anybody else to come in and compete. And reserve margins are overall coming down from 11 to eight percent. We're looking at a real supply shortage in the short term.

How do we fix all this? There are the traditional methods. The successful states have big shopping credits and high prices so people can come in and compete. You can educate customers about the volatility and the risk and how to hedge. The retailers can come in and offer fixed-priced contracts, but unless people know about them and don't just trust the fact that they're going to get a nice, levelized price like they get under the regulated regime, they're not going to make the change even if it's out there.

We need to standardize business practices. There have been efforts, like the Coalition For Uniform Business Rules. Edison Electric Institute has a standard wholesale contract; they deal with the National Energy Marketers Association. There was an effort to bring these things to the forefront, but they didn't go very far. A lot of utilities that spent money

on their software are resisting changing to standardized business practices. We need to fix the wholesale markets and transmission.

The likelihood of success of these traditional methods is pretty slim. What we need very badly is triage. We cannot have another San Diego if we expect any other markets to open up to competition. How do we jump-start things? We need to get things going really fast and, in particular, to get hedging options to customers. Without forward contracts, you're going to have the price spikes pass through. The real problem is getting the regulators to come up with a paradigm where the utilities can go forward. It has been difficult to get the utilities in California to be counter-parties to any sort of forward wholesale contract, which could have spared customers in San Diego.

Conversely, if a retailer can go directly to the customer, you can bring a hedged product in. But how do you get in without the economy of scale? You can do an allocation methodology similar to what they did in Atlanta a year or so ago, where you start up a market and at a certain point in the market development you get whatever percentage of the market you had at that point and they allocate the whole market. There's a lot of resistance to that, called governmental slamming of customers by many. You can sell the provider of last resort or default role. I think that has some promise but there are a lot of issues.

The last idea is streaming. The assumption is that the utility could actually perform the aggregation function. They might recruit four or five or half a dozen wholesalers to offer forward contracts directly to the customers, perhaps through a billing insert check-off. That eliminates all the acquisition costs that we were talking about a moment ago. You make the utility the back room. Have them do the billing for the retailer, similar to what goes on in telecom today. The utility could still sell its spot for those who wanted to ride the market but they would be facilitating hedging by the customers. A lot of people say customers aren't ready to take the fixed price risk. But I think people could get used to that in power and in gas.

There are some challenges and issues. The biggest one is inertia; people don't move until they have to. But I think with what's going on in power and gas prices these days, people are going to be looking for a solution to a problem. Other challenges are customer mobility--when they move, what happens if they checked off a four-year deal with one of the wholesalers? And dealing with load profiles and usage--you've got to decide how much you're going to sell the customer and when. I don't think that's an insurmountable problem. Customer education is a challenge.

One of the biggest issues may be the stranded consumer protectors, people

who want to have rules that say the customer can only do this or can only do that. A lot of the implementations we've seen in retail across the country limit the customer to a certain period of time for its contract. And figuring out a way to stream wholesale, hedged product-through to customers doesn't resolve your lingering transmission issues.

Why do it? I don't think we have a choice. Something has to be done. Right now the regulators, if California's the model, are basically paralyzed. The politicians have gotten in. Nobody's going to let the utility distribution companies hedge without the ability to second-guess them. The UDCs aren't going to hedge if they've got that problem. We're going to have supply shortages. I think we're going to have a consumer revolt if we don't give them an option. And right now there's a lack of political leadership to get out there and make some change. My sense is that if the UDCs and the wholesalers, the generators, got together and figured out a solution, that solution would be accepted.

Speaker Two

My bottom line is, retailing is virtually dead in California. The problem is not so much that customers want choice. Customers want to have low prices or at least not unreasonable prices, and they regard the current wholesale prices as unreasonable.

Is there a retail future in the short run?

We're looking at a situation that is essentially political and, at its root, may be a nationwide problem. We have an infrastructure crisis, and we're seeing the leading edge of that in California. It's largely a matter of the tremendously successful economy of the last eight or nine years. And it's exacerbated in California by the NIMBY attitude, which is alive and well there. Nobody wants a generation plant or a transmission facility in their backyard. This nation is going to continue to have problems until it comes to grips with the fact that it can't have everything and that it has to make a decision. And if the decision is to cut back or somehow economize on transmission and generation, then you're going to have environmental rents being flowed through in electricity prices or some other device used to allocate scarce energy.

California set up a structure that everybody understood was not particularly friendly to retailing during the price freeze period; that is, the CTC was being calculated on a residual basis. The amount that was positive has gone negative, and that's the problem we're facing today. San Diego managed to escape by paying off their stranded costs by June 1999. When prices were revealed to customers at the retail level, the political process said, No way!

It's important to recognize that the problem in California is not volatility; the problem is high prices. People have been returned to the utility

because it's too hot an environment for retailers. Current prices, by comparison to previous years, are on the order of three or four times those levels. But the difficult stuff to explain is not the high prices, but the high prices at relatively low load levels. The peak in California is about 45,000. Prices didn't go up spectacularly until the vicinity of high 37 to 40,000, whereas those very high prices are experienced as low as 32 and 33,000. Now, of course, there are a lot of outages on power plants. Whether those are really forced outages or whether something else is happening is something the market monitoring committee is looking into.

What's the impact of these high prices? San Diego escaped early, but they are impacted by high prices since a rate freeze has been reimposed upon them. So they're incurring undercollections. PG&E and Edison are incurring huge undercollections in a considerably more complicated political and legal environment. A \$10 million loss is a good day.

Factors are market structure, including screwed up market institutions, as well as allegations of market power. Sorting all of these things out is extremely difficult and is made more so because of what's happening in the natural gas market. The prices have gone up from 15 to 26 to 32 to 40. You can't operate under a \$250 price cap when you've got to pay that at the margin for gas. There's a lot of margin recovery, and people wonder whether they ought to

call it monopoly, scarcity rents, consider it illegal. The Market Surveillance Committee has said they think there's market power, though there are criticisms of that. California has had tremendous growth rates. Generation is in various stages of siting, but it doesn't look like it will come on until 2003.

I agree with others that the FERC order of November 1 [proposing remedies] wasn't very good. And the Governor's set of recommendations the other day are less than aggressive or overwhelming. My interpretation is that he's waiting for the FERC to do something before he does something more aggressive. So you've got FERC waiting for the state and the state waiting for the FERC, the utilities bleeding, Wall Street wondering whether they ought to loan these suckers any more money, the generators wondering there's a future in California, and the governor and others rattling sabres and saying we might have to nationalize all you guys and take you over.

So what does all this have to do with retail? Well, it seems to me that there isn't any retail going forward. To put it a bit differently, the political pressure is to protect consumers. I don't think there's any way out but to have a retail price freeze that's underwritten by the utilities. It kills the retail market, but I think a more aggressive action that would try to create a retail market without a lot of help from generators with low prices

that they would flow through just isn't in the cards.

Speaker Three

I am going to talk specifically about Illinois. The northern part of the state, centered in Chicago, is about 70 percent of the state's population, so that is the focus of restructuring efforts. Illinois passed its law in December 1997. We opted for a phased-in approach to customer choice starting in October 1999 with the largest customers and large aggregated retail customers. Then we gradually phased in the rest of the business customers. The industrials are now phased in, and the remaining commercials will phase in by the end of this year. We held the residential market back until May 2002. However, some might argue that the residential actually got the best deal because they received, more than one year prior to the first open access, a 15 percent rate reduction.

Several provisions in the law provide for the utilities to recover their stranded costs. You can restructure your asset portfolio, accelerate depreciation on your nuclear assets, secure ties, portions of your revenue stream, and sell competitive value-added services and use that as part of your stranded cost recovery.

The period through which the utility can collect transition charges, to the extent they apply, is 2006. It uses a formula that is the difference between

the revenues you'd collect under regulation and at market, and that applies only to the customers' buy-in at market prices. How you determine the market value of energy is critical to whether or not the market works or not from a retail marketer's point of view. The transition charge is non-bypassable except for a limited co-gen exemption.

The utilities also have to offer certain types of commodity products. There's an obligation to offer real-time pricing and a power purchase option. Co-ops and munis are generally exempt unless they choose to compete, in which case they can become active in the market just as a retail marketer. There's a ceiling at which point, if your earnings exceed that ceiling, there's a 50/50 sharing with the customers above that point.

There is a securization provision. That wasn't so much to keep competitors out of Illinois as to try to encourage the surrounding states to open up their systems as well. The utilities are filing delivery service tariffs. They're cost-based, so it's not a residual that goes to pay for delivery service. Customers can return to bundled service, but there is a minimum commitment that they have to stay for 12 months once they exercise that choice. The law balances the objectives of consumer protection and maintaining the utilities' financial viability, as well as other stakeholders.

As far as how our stranded costs are calculated, we start with the base rate

for customers over three MW. From that, we make three subtractions. The first is the market value of energy, which is an administratively determined value. We started off with a process called the neutral fact finder. We've tried to make improvements to that by moving to more of a market index approach, but that's the credit for the energy component that gets deducted. Then we take out the delivery service, average cost per kwh, and a mitigation factor which is a credit that the utility basically eats as its contribution to a stranded cost recovery, and it also provides a little headroom for shopping credits.

How does that look to a customer? If the customer was paying six cents, now he goes into the market and finds a marketer with a price of 3.6, pays his delivery service and his CTC, so his new price is 5.4 cents. This customer saves 10 percent, but it's very sensitive around the negotiated energy cost. If that was 3.8, the savings would drop to six percent or 6.5. So the drivers that facilitate competition or inhibit it are that, for the customers within any given class, there's a wide variability around the base rate number. So the starting point will drive how big the CTC is. The effective shopping credit is the combination of the mitigation factor and the administratively determined market value of energy.

Non-residential customers get a power purchase option, which means that whatever the outcome of that administrative process is to create the

market value credit for energy, all business customers get an option to buy at that price from the utility. It's a tariff, something the utility has to offer and educate customers on at least twice a year as to its availability. That has a definite impact on retail competitors because it's the price to beat. As opposed to ESPs, we have the Alternative Retail Electric Supplier in Illinois, with account managers to help them through the process.

Fourteen months in, the largest utility has had about 8,000 customers switch off their bundled rate to go to some unbundled supply. This represents 13 percent of the utility's eligible customers and 47 percent of the eligible load. So it's heavily weighted towards the large end of the industrial and commercial class.

Who's competing? Almost all are Illinois utilities or affiliates of utilities. There's been a strong effort on the demand side by the largest utility, offering programs both directly and to retail marketers so they can resell those programs to their customers, and it's been very effective.

As for some of the growing pains, one is getting that market value right. The neutral fact finder process is if there's no other visible market price that everybody can agree on. In some seasons, it seemed to get it right, but in other seasons, particularly the summer, it was producing prices that were well below the real market value of power. So the utility moved to a market index

approach, using indexes like All Trade and Bloomberg because they gave better price signals and reflection of actual market prices.

We've spent a lot of time on standards of conduct and functional separation. Utilities in Illinois are allowed to compete for commodity, but not all have opted to. The dilemma has been, how do you keep all those commodity products that the utilities are obligated to offer without creating any opportunity that the utility could leverage its essential facilities? We also have strong opposition to IPP siting, getting local zoning approvals for permits, etc. It has been a real dilemma for the IPPs.

One of the key things that we need to look at going forward: In 2004, residential rates in Illinois will be 20 percent lower than in 1994 on a nominal basis and probably over 50 percent on a real basis. Given that, what would be customers' motivation to participate in the market, even if the marketers are there? Post-transition, the law contemplates the utilities will have an ongoing obligation to serve and offer energy at market-based prices plus no more than 10 percent to cover their O&M costs. What is the market price? Is it the spot market, the hedge product? Whatever that default service becomes will determine whether or not we'll ever have real competition at the residential levels.

Speaker Four

Pennsylvania is generally perceived to have had more success in electric restructuring than other states. At least, we've had fewer catastrophies. But we didn't deregulate our utilities; we restructured them in a way, and unbundled their rates in a way, that allows for competitive providers to compete for a portion of the unbundled utility service. Obviously, we still regulate the distribution service. And in fact, we still regulate the generation service of the utilities, but we do it through price cap regulation rather than traditional cost-of-service regulation.

I think the most important provision in the Pennsylvania electric restructuring law is the rate cap provision. We have long-term generation rate caps. Under the statute, they were supposed to go out to 2005. We now have settlements and some of them go out as far as 2010. Why did we want to have rate caps in 1996 when we negotiated the law? Well, we were afraid that no matter what we did, we would screw something up, and we didn't want people to be worse off than they were prior to the legislation.

We didn't set our rate caps at a level so low that they either imposed great pain on the utilities or made it impossible for competitors to compete. Our rate caps were not based on wholesale spot prices. They were based essentially on pre-existing retail prices that had been found to be just and reasonable, and the object was that a utility could not charge more for its generation as long

as the rate cap was in effect, including their standard cost provision. So, they couldn't charge for more than generation plus stranded cost than they were charging for generation back in 1996 under the rates that had been found to be just and reasonable.

The rate caps are designed to do three things: First, to make sure that customers who do nothing are no worse off than they were in 1996. Second, to allow our utilities to recover an agreed-upon level of stranded costs, which were pretty high, over a reasonable period of time. Third, to allow enough of a margin that competitive electric generation suppliers still have the ability, in most territories, to beat the utilities' generation price and actually offer some benefit to our customers.

The rate caps are fixed. They weren't residual rates. We didn't require divestiture. Some utilities did divest, but that was voluntary. We don't force our utilities to sell into or buy out of the wholesale spot market. We don't perform a prudence review of how they meet their rate caps. If the utility can generate or acquire power for less than the rate cap, they get to keep the profit. If their costs are higher than the rate cap, they eat it.

What's happened in Pennsylvania? Most customers did see some negotiated rate reductions even if they didn't shop, ranging from two, three, four to a high of eight percent in one case. Also, some customers did enter

the market, including residential customers. About 550,000 customers, or about 10 percent, had switched to alternative suppliers as of October 1 of this year. The shopping, as one would expect, is greatest in places where the previously regulated prices and the shopping credits are the highest, and lowest where the potential savings are the lowest. There are also substantial numbers for industrial and commercial shopping. Depending on how much you use and who you shop with, you can save \$5 or \$10 a month. You can buy green products.

Has this shopping experience been a smooth ride? This summer, we discovered something called the donut contract, or what I call the yo-yo contract, where a marketer would offer service particularly to the commercial and industrial customers throughout the fall, winter and spring, then dump their customers back onto the utility at the capped default rate for the high-cost summer months, then take them back when temperatures and prices went down in the fall.

New rules approved by the PUC require that if a commercial or industrial customer goes back to the utility, for example, for a high-cost summer period, they have to either pay the market rate during that high-cost period or stay for 12 months. So there's no way for those customers to game the system. So far, that rule has only been applied to industrial and commercial customers. I don't see residential customers doing a lot of

gaming.

On the other hand, some residential marketers have left the market. They have either left their customers with the supplier of last resort or, in some cases, have been able to get another supplier to take over that group of customers. But given customer acquisition costs, it's not a good strategy to go out and spend lots of money to get residential customers just so that you can dump them and lose them forever.

We had some developments on November 29, a couple of which are very good. The PUC approved for Duquesne what's called a POLR II, Provider of Last Resort filing. Duquesne divested its plants, but at the same time entered into a contract with the purchasing company to meet their POLR load at the capped rates. Because their divestiture was so successful, their stranded costs will be paid off by late 2001 or early 2002. Some propose that at that point we could take the San Diego approach and expose people to the wholesale market price. They decided not to, and came up with the idea of extending their contract with the purchasing company through 2004 at a higher shopping price. If Duquesne's residential price is 10 cents, three cents of that is stranded costs. If we get rid of that stranded cost charge, which we will do, rates go down 30 percent. So we have a 30 percent rate reduction, but we're increasing the shopping credit by a penny. So, the rates go back up by

10 percent. So, net, Duquesne customers will have a 20 percent rate reduction at the beginning of 2002 and a substantially higher shopping credit, which one hopes would bolster the ability of competitors to compete for Duquesne's load at the same time it lowers rates for everybody.

The second good thing that happened was that the PUC approved our first successful competitive default service. PECO tried, but the initial bids were unsuccessful. Then they were permitted to enter into bilateral negotiations. NuPower came forward and won the negotiations. They bid to get 299,000 of PECO's customers, which is 20 percent of the residential customers, providing them with default service at rates that are two percent less than the PECO default price and that includes a two percent renewable requirement.

What I consider the bad news on November 29 was that GPU filed the first petition for a deferred recovery, or it could be a refund theoretically if POLR costs above or below the rate cap levels. GPU was the other company that divested. They had hoped to auction their competitive default service, but their auction so far has been unsuccessful. Creating cost deferrals is contrary to what we had in mind when we set up the rate caps.

So, the Pennsylvania model has been a series of pragmatic compromises at the retail level designed to protect consumers while permitting utilities to

recover their stranded costs and leave enough room for retail competition to get started. It is critical to get the wholesale economics right. Most consumers in Pennsylvania are fortunate to be served by utilities that are part of PJM. We've been fortunate that our compromises have worked on the retail side. And the economics have worked pretty well on the PJM side and, therefore, I am encouraged that Pennsylvania is moving in the right direction.

Discussion

Question: For the bulk of the consumer marketplace, it isn't worth spending the money to get a customer. Is that in itself not evidence that regulation has been pretty successful with respect to the energy commodity? And if that's the case, is there a different dimension to deregulation, the promotion of competition within the electric utility industry, that doesn't have anything to do with the energy commodity itself?

First Response: If there is going to be a future mass market in retail, you have to have massive consolidation within the industry. Rather than having 300 or so different IOUs in the country, you need half a dozen or a dozen major market players across the country on a standardized platform. Then you get more efficient than the regulated state.

Second Response: Even if there is not much margin there, regulators have to

be willing to accept that kind of contestability and simply live with it and say OK, the market is open, the incumbent has 95 percent of the market, but everybody is free to shop. I haven't seen that willingness. Regulating the incumbent with such things as reasonableness reviews just gets us back to a quasi-regulated world.

Comment: I have seen the streaming concept before as the Virtual Direct Access concept developed to try to find an efficient way for consumers to get access to the wholesale market. This was the strategy pursued in the California restructuring; we thought once consumers could see the spot price, they would sign contracts with ESPs. An additional challenge is distrust or misunderstanding of the whole concept of ESPs. The incumbent distribution utility can really be of assistance to new entrants.

Response: The problem is one of discontinuity to some extent. The market was reasonably stable and then all of a sudden going nuts. If people in San Diego had just gotten mildly disgruntled, you could have pushed them off the system, to people who could hedge for them, the ESPs. So they wouldn't have particularly been bothered by volatility.

Question: Has California seen a fall-off in proposed plants in response to the gas price changes or price caps?

First Response: We look at California

and say, sooner or later sanity will prevail. We're going ahead with repowering projects, adding scrubbers and things of that nature. But we're not spending the real money until sanity does prevail.

Second Response: It's an infrastructure crisis as much as anything else. One aspect is the need to produce turbines. But once you have a finite number of turbines, they're going to go to the highest bidder. If somebody has a sure thing in terms of market structure and a sure prospect, you're going to stick your turbine there.

Question: Is it possible, even with all of the regulatory interventions in California, Pennsylvania and Illinois, to have a competitive retail market if you don't have a competitive wholesale market?

Response: The regulators were too unwilling to walk away from a controlled retail market. Basing a shopping credit on the wholesale spot market, for instance, is not a bad concept. But you need more margin than that to attract retailers. Yet the regulators were never willing to make default service any fatter than that.

Comment: Often, utilities are uncomfortable with retail. Infrastructure development is key. And we all have to deal with flexibility. One of the criticisms of the California market was there was not enough flexibility of such intent on giving market signals that they forgot if they

developed rate shock, it could come back and kill the whole idea of competition.

Response: I don't think it's a coincidence that when Enron finally decided to get into the retail market, the partners they brought in were IBM and America Online. I think that's part of where we are going. The lowest prices are being offered by the online energy providers. They are trying to offer something other than electricity.

Question: When we initiated restructuring, did we throw away one of the most important assets in making the old system work, which was the political skills and abilities of the vertically integrated utilities, and if so, what are we going to replace it with?

First Response: Yes, but you would be surprised at what great respect PJM, as an institution, has.

Second Response: I would up the ante and say that there is a tremendous leadership vacuum in the power industry these days. RTOs think they can handle it, but nobody is.

Comment: You can't have efficient wholesale competition without retail competition, because it is from retail competition that you get the necessary demand response and a true incentive to exploit that price volatility and gain efficiencies.

Response: I agree, but would add that the reasons California adopted retail

access had a lot more to do with the socialization of risk-taking in choice of generation that was taking place before that time, and the fact that the process had been captured by the supply-side interests. In other words, maybe one of the faults of the old institution was that it tended to oversupply. But the one thing it did do was socialize the risk-taking, first with nuclear plants in the 1970s and QFs in the 1980s, then with more QFs and IPPs in the 1990s.

Question: It's the rate cap that you consider to be the success in Pennsylvania. New Jersey also has that yo-yo effect, even with switching restrictions in place. What is the end vision? It's not the rate cap; it's not beating the yo-yo game.

Response: There are two possibilities. One is at the end of the road, and that is that the electric distribution company of the future will look like the local gas distribution company of the past, which buys gas at wholesale and sells it at retail with no markup. They buy some on the spot market, some on long-term. The other is that by the time we get to 2010, we will have a vibrant wholesale market, new metering technologies, a lot of marketers who are interested in getting electric service customers.

Comment: I am struck by the fact that nobody has talked about how to empower end-users, preferably with some kind of demand-side management tools.

Response: In San Diego this summer, customers got exposed to prices that they weren't seeing immediately. If they knew what their prices were going to be ahead of time, maybe they wouldn't have used so much. I think customers can tell the difference between different prices. This isn't rocket science.

Comment: There is a structural divide in that retail access can only come one state at a time as long and no state can create a viable liquid retail market on a state by state basis, whereas on the wholesale side FERC does have the ability to organize the market with rules that are inter-regional. So it is easier to focus on creating properly organized wholesale markets in the hope that the retail ones will then match up--or, what I have been preaching recently, to force state and federal regulators to talk to one another and design common rules for both.

Response: The California experience bears witness to that. In 1994, the concept of retail wheeling came up, which didn't say anything about upstream, what we now know to be the wholesale market. The idea was everyone was going to get a choice. That was the extent of the intellectual forethought. So California worked on things for several years with FERC not even participating and with participants knowing hardly anything about transmission. So, I agree: Don't start with retail before you've done heavy lifting upstream.

