

Harvard Electricity Policy Group
Thirty-Eighth Plenary Session

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RAPPORTEUR'S SUMMARY*

Session One: Do Transparency Requirements Cloud Good Decision-Making?

The recent decision of the D.C. Circuit Court of Appeals (No. 03-1182, December 10, 2004) barring off the record contacts between market monitors and FERC decision makers is the most recent of many complaints and decisions which affect the flow of information to regulatory decision makers. The motivation of measures such as sunshine requirements, limitations on ex parte communications, limitations on use of information outside the formal record of a case, and restrictions on contacts between regulatory "advisory" and "trial" staff, are all well motivated measures designed to assure fairness, honesty, and transparency. Unfortunately, they may also have the effect of restricting the flow of critical information to decision-makers, of impoverishing the dialogue and discussion among commissioners, of confusing regulatory quasi-legislative and quasi-judicial functions, of driving up transactional and process costs, and of bureaucratizing and perhaps, in some cases, even paralyzing decision-making. Clearly the positive attributes of transparency requirements are highly desirable, but what are the downsides of such requirements? What is the appropriate balance to be struck between the goals served by transparency and the goal of effective and efficient governmental decision-making?

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

Speaker One

Regulatory agencies combine three different governmental powers. They're quasi-judicial in the sense that they do ex-post evaluations, resolve disputes between specific parties, and bind the parties with their resolutions. They're quasi-legislative in that they make decisions for prospective application, such as rate making. They are also executive agencies.

Each of these three branches of government has constraints on how it makes decisions, along with areas of discretion, but regulators do not get the same discretion. They are far more limited in their ability to gather information, communicate with one another, and make decisions. These limits are well-intentioned, and some make a lot of sense, but they have real adverse impacts.

Sunshine requirements and restrictions on *ex parte* contacts limit communication between commissioners. They empower agency staff, who can effectively become decision makers by filtering the information that they deliver to commissioners. These constraints also restrict the flow of information, as in the EPSA case. FERC oversees real-time markets, and if it has to go through a formal sunshine meeting to talk to people about what's going on in the market, it cannot operate in real time. Openness requirements also make resources less useful, as illustrated by FERC's inability to talk to market monitors.

It is not always clear who benefits from sunshine laws. In many states there is almost no media coverage of

commission meetings, so the rules serve mainly to keep lobbyists fully informed.

Ex parte restrictions constrain the flow of information, sometimes legitimately. They level the playing field in the decision-making process and inhibit the use of untested information, but they also preclude commissioners from getting information that might be quite useful in making decisions. There are exceptions under federal law and in some states, in which you can have *ex parte* communications as long as they are subsequently disclosed, but that exception does not exist in many states.

Constraints on regulators' discretion should be limited to the task at hand. For legislative issues, such as rule-making or rate cases, legislative constraints and discretion should apply to regulators, and quasi-judicial or quasi-executive functions should be treated similarly. We also need to recognize the real-time nature of markets. Electric utility regulation was set up in days when things moved more slowly. The EPSA decision shows that our laws on regulatory discretion and decision-making in the context of competitive markets are out of date.

Question: How many states are subject to sunshine laws?

Response: It's probably a majority, but I don't know the number.

Speaker Two

Let me start by discussing the inherent benefits of openness and transparency, and the inherent drawbacks of secrecy. First, openness brings accountability and scrutiny to the system. Second, our

regulatory agencies work most effectively when they can adapt and self-correct, which requires some level of openness. Transparency and information-sharing promote better risk assessment and adjustment. Finally, openness and transparency lead to more lasting, meaningful participation in government.

The news media short-circuits meaningful participation by not covering these important regulatory issues in enough depth. Scant coverage of the EPSA decision is a good example – I found two trade press articles on it in a voluminous Lexis/Nexis search. We have learned to reflexively assume the worst about any proposals to revise access laws, largely because of destructive proposals from legislators, but we need to find a more productive way for journalists and regulators to talk about these issues.

Finally, here are some incentives for secrecy at regulatory agencies that make transparency discussions challenging. Secrecy empowers staff, because when commissioners or agency heads are limited in their ability to discuss policy, they use staff as information conduits, and staffers start to court the press and leak information. Maybe we can address that issue by providing for disclosure of communications after the fact in instances like the EPSA case.

Another incentive is that secrecy hides mistakes. Through the years, covering a variety of industries, I have often seen secrecy used for political cover. And in a regime of secrecy, any disclosure – especially of error – is seized on by the press. The regulatory scene in Washington now is one of disclosure by

drips and drabs, and more and more litigation, and the resulting disclosures take on far more merit than they deserve.

Finally, secrecy allows for strong, lasting relationships between agencies and special interests. We who are charged with providing scrutiny over government agencies and holding them accountable are bedeviled here because we have to look at not only your actions, but also at our own.

Speaker Three

In the EPSA case, the DC Circuit struck a balance that largely favors transparency in the use of private market monitors. Too much openness presents some risk that market monitors may not be forthcoming with FERC. As a result, the decision may deter timely reporting of problems by private market monitors in deregulated wholesale power markets.

EPSA successfully challenged two FERC orders that attempted to amend a FERC rule barring *ex parte* off-the-record comments. FERC's challenged orders exempted from the Sunshine Act certain communications between private market monitors and FERC decisional employees. Under the rules as interpreted by FERC, the communication would be included on the record only if FERC determined that it relied on the *ex parte* communication in reaching a decision.

The DC Circuit determined that FERC is required to do more since the Sunshine Act uses the word "relevant" to qualify which *ex parte* contacts must be disclosed, not the more limiting word "rely." I would say, however, that the court probably over-reached a bit by

subjecting to pre-enforcement review a rule that leaves discretion to the agency, where there has yet been no specific statutory violation of the Sunshine Act.

FERC's new rules were vacated altogether, which leaves some uncertainty as to how, if at all, the agency can use market monitors. If transparency deters independent market monitoring, it may thwart effective agency and RTO enforcement of market rules. Without that effective monitoring and enforcement, courts may tilt the balance away from *ex ante* agency enforcement and RTO self-governance, and towards *ex post* judicial enforcement of market rules.

How do we preserve a role for FERC and RTOs in market monitoring in order to keep judicial enforcement at bay? The DC Circuit left a few safe harbors. I think FERC can still use market monitors in its day-to-day monitoring and enforcement work. So long as the discussions between private market monitors and FERC decisional employees do not involve contested issues, market monitors can flag potential problems and exchange information with in-house staff at the pre-adjudication stage and in the context of more informal adjudicatory proceedings.

FERC can also have market monitors play some role in its broader quasi-legislative work. Market monitors may meet with FERC decisional staff and commissioners to influence policy guidelines or to inform the agency in processes such as rule-making.

In the EPSA case, the DC Circuit clearly struck a balance in favor of openness.

This potentially thwarts the timely and complete disclosure of problems in deregulated wholesale power markets by independent market monitors. We also need to recognize how this pro-transparency approach might affect the institutional balance in enforcement of market rules. In this context, there may be some advantages to a properly-designed active agency enforcement regime, such as more reliance on agency expertise, more uniformity, and more predictability than will be achieved from relying on courts to enforce market rules. The Ninth Circuit has recently suggested that FERC has to actively monitor and enforce the rules, or we will increasingly see courts intervene in disputes and apply antitrust laws or state contract and tort law doctrines against market actors.

Question: Can you explain the distinction between “relevant” and “rely” in the EPSA opinion?

Response: The statute requires that “relevant” *ex parte* communications must be disclosed. Relevant is a pretty broad term as interpreted by courts. FERC proposed only to require disclosure of *ex parte* communications to the extent FER determined that the agency itself had relied on that communication, which is a much narrower construct. Many things might be relevant without necessarily influencing the outcome of the decision.

Question: What is the justification for requiring that no person shall have an *ex parte* communication?

Response: The issue is which entities this ruling covers in the context of formal adjudication. The DC Circuit

suggested that private market monitors are like FERC staff, but it did not go so far as to suggest that market monitors are agency actors or decisional employees. I think the court clearly intended to say that private market monitors are persons, not agencies.

Comment: The practical issue currently facing FERC is how to respond to this decision, and FERC wants to do real-time enforcement and to get real-time information in the event of a problem, rather than cleaning up the problem in the messy and inefficient way that we saw happen in California.

Speaker Four

Transparency is the worst way to run a regulatory agency except for all of the other forms. We are stuck with a certain amount of transparency, and the challenge is to find some creative fixes to distinct problems.

As a consumer advocate, I feel very strong about the need for transparency and equal access to decision-makers. Consumers generally draw the short end of the stick on those issues. Utilities and other interests have ready access.

Regulators need to realize that they are in show business, and that in all of their roles, they must communicate that the public is involved and that everything is open and aboveboard. Regulation only really works if the public has total confidence that regulators are working and making decisions in an open manner.

Any type of transparency system in the regulatory world must be changed frequently, so you have to establish

feedback devices of some sort to make sure that disclosure rules are working and will continue to work. Disclosure rules should be revised or changed or updated every year or two.

Comment: The EPSA case, as a matter of law, was rightly decided, so there are basically two choices. Either the law should be changed, in recognition of the fact that New Deal-type regulatory agencies can no longer accommodate the kind of markets that occur in the energy industry, or we will have to decriminalize *ex parte*.

We can't really do away with *ex parte* rules at the federal level. FERC tried to get a small exception in 1990 and 1991 to let commissioners have purely policy discussions as a group in private, as long as the agency's chief legal officer was there to ensure that they did not get into specific adjudicatory cases. Every newspaper and consumer advocate in the country opposed it and argued against changing one word of the Sunshine Act. So the dilemma is, can the current responsibilities that we assign to regulators, where they act in both a quasi-legislative and an adjudicatory function, exist under the current statutory framework? I think the answer is no.

Response: There are some informal mechanisms regulators can use, although they're strongly discouraged from doing so, such as off-the-record but open meetings. I don't think that is used very much, but it may be another avenue that FERC could use for talking with the market monitor. There's a medium-ground position that FERC uses in legislative proceedings, which is to say, I had this *ex parte* communication. I may

have meant or not meant to have it happen, but everybody needs to know about it. And you make subsequent disclosure, and that cures the problem.

Response: In California, we have adopted a policy called the all-party meeting, under which if a commissioner wants to get a sense of the story from one party, he invites any of the parties in the proceeding to come, and they all talk at the same time. And frankly, the commissioners get better information from having all the parties at an informal meeting than they would have at an *ex parte* meeting.

Response: The DC Circuit rejected the notion that this is going to be a sort of balance that we can strike on a case to case basis. This is monolithic language. It applies across all regulatory agencies. And I think you're right, that this statute and other statutory aspects of FERC's governance procedures will need to be revisited in the future. As we increasingly privatize governmental functions at the federal level, we might need to revisit some of these *ex parte* and sunshine requirements.

Comment: Another question for those of us in the media is whether or not real-time disclosure and subsequent disclosure are equivalent.

Response: I don't think so, because you may learn that there was a discussion, but you won't necessarily know exactly what was said, and you may not be able to get a meeting to provide a counterbalance before the decision occurs. We have telecommunications technologies that allow for inexpensive group meetings. There is no reason to

rely on meeting serially when it is so easy to get people together at one time.

Comment: Creating an adequate public record is another issue. With subsequent disclosure, we would have to think about how voluminous and detailed those requirements would be.

Question: Can internal agency reorganizations help to foster the kind of feedback and flexibility that would make transparency rules actually work in this context?

Response: We are moving to different sorts of regulatory instruments, different mechanisms for governance of industry, including private mechanisms. And as we reassess regulatory tools, we are going to see a different set of legal regulations on communications and disclosure. It will be a big issue as FERC reassesses its monitoring and enforcement task.

Response: The California ISO wrestled with this when it created disclosure rules as part of trading. It turned out that those rules were being used against the market, so if they had had a feedback loop in place by which they could figure out whether the rules were working as intended, they might have been able to change the rule so that abuses might not have occurred.

Comment: These are repeated hourly markets, so people get information very quickly and learn how to thwart or game the rules. The timeliness of information disclosure has to be assessed in terms of possible unintended consequences.

Question: FERC tried to operate differently to respond to changes in the

market, and the DC circuit didn't like it. What should we do now – seek a re-hearing, change our policies, ask Congress for funds to hire our own market monitors?

Comment: Secret communications between market monitors and FERC worry companies, because we may have a different perspective that FERC needs to hear. We would like the opportunity to participate in those conversations.

Response: This is a complicated issue. By delegating responses downward, you may prevent issues with policy implications that FERC wants to resolve from getting to the Commissioners. And if market monitors see patterns in several regions, do they need to call every company that is potentially involved?

Response: You cannot accommodate the existing adjudicatory and legislative roles without a change in either the law or FERC sunshine regulations.

Comment: We need to move away from having regulatory agencies operate in a judicial role. It is the wrong mode for making the kind of decisions that FERC and state regulators have to make constantly now.

Comment: As a public interest advocate, I worry about the information that regulators receive. Not all advocates have access to the same data or equal resources to analyze it.

Response: That is a fundamental problem, and sunshine laws do not solve it.

Comment: About fifteen years ago, my state amended our open meeting law so

that the PUC was allowed to hold private deliberations in a fully submitted manner, which is essential. Final decisions are complicated package deals. FERC and the states need a way to sit down and thrash out the issues that are impeding progress in this industry.

Question: How do you engage and educate the public in this field? It is hard for citizens to just show up and impact our decisions on complex issues.

Response: The public is interested largely in scandal and failure, so regulators tend to get negative attention. My organization is a good model that should be considered by other states. It was created to be an informed, knowledgeable resource that could connect both with the public and with regulators.

Response: The candor argument essentially says that we want to be blunt and can't do it directly. I disagree. If we want to criticize a program or a nominee, we should be able to say so loudly and publicly. That is the price of our transparent system.

Response: But if regulators are not sure of the facts and want to test out ideas, they are more likely to do it in private than in a public meeting.

Comment: Commissioners are human, and some are shyer or less articulate than others. Spontaneity is very important, and you get it in small group settings, which also make decision makers feel more accountable to each other. If you get a better decision from private deliberations, that will promote public trust.

Comment: Two of my former partners argued for municipalities in the EPSA case. We felt that the *ex parte* rules were clearly violated. In a contested on the

record case, market monitors should be in the litigation mode, not advising agency staff. File your testimony and let us hear you like everybody else.

Session Two: Distribution Pricing: Do Revenue Caps Set Appropriate Incentives? Are They Fair to Consumers and Investors?

Debates over the pricing of distribution pricing have generally been waged between advocates of rate of return vs. supporters of price caps. Environmentalists and others have pointed out what they saw as a critical flaw in both of these methodologies, namely the linkage between throughput and revenues/profits, a relationship that they contended encouraged consumption and discouraged the efficient use of energy. Decoupling profits and throughput gained some currency among regulators in the late 1980's and early 90's, the heyday of Integrated Resource Planning (IRP). With the onset of competition, that debate seemed to fade. The issue, however, has re-emerged. Norway began to use revenue caps and now several states have either adopted them, or are actively considering them. The efficacy of revenue caps is once again becoming a front burner issue in distribution pricing. Naturally, there are innumerable questions raised. How does one establish the appropriate level of the cap? How much flexibility is there in the cap? Which cost components (e.g. fuel or purchased energy costs) should be internalized into the cap, and which should be treated as exogenous? If energy and/or fuel are exogenous, does that diminish the effect of de-linking throughput and profits? As a practical matter, if distributors provide primarily, or, as is the case in some states, only, wires services, how effective can revenue caps be? Do they skew the risk/reward ratios, and if so, how? What has been the track record of revenue caps in regard to investment in energy efficiency and demand side management? What is the appropriate baseline for applying revenue caps, actual costs or some form of benchmark? If the latter, what type of benchmark is most effective? How are productivity expectations, including energy efficiency gains factored into the revenue cap ratemaking equation?

Speaker One

The key question with respect to revenue caps and other similar measures is what you want them to do, and whether caps will accomplish those goals. Whatever model you use has to be durable over time.

The basic variables that regulators may seek to influence are fuel usage (by the company and its customers), plant investments, and quality of service. There are many ways to treat these variables, such as per-unit rates, inverted rates, and capped rates for specific or indefinite time periods.

The ways in which you mix and match these elements will have different impacts on behavior. Revenue caps seek to make companies more efficient and invest in plants, because if they can provide service more cheaply -- for example, by reducing payroll or improving their facilities -- they will increase their profits. But revenue caps may also be incentives to spend no money at all, especially in the short run.

Commissions set a cap or benchmark based on predictions about the future, but the universe is not static. If a company's costs increase because of fuel prices or a plant outage, there will be pressure to change the benchmark, and

the more often it is adjusted, the less it is really a cap.

Personally, I like inverted block pricing, where plant and O&M are bundled together based on a rate of return on investment, but fuel costs are either decoupled or somewhat separate from fixed charges. This is how we regulate water in my state – consumers pay a fixed cost to maintain the pipes in the ground, plus the costs of water they consume.

Traditional methods like this are more adaptable than benchmarks and caps, which promise more than they ever deliver given that they need to be adjusted when conditions change. Traditional regulation anticipates changing and adapting over time through rate cases.

Speaker Two

Revenue decoupling is simply breaking the link between utility sales and revenue. It is meant to remove companies' financial incentive to promote higher sales, which generally produce larger revenues and larger profits. Another purpose is to eliminate utilities' financial disincentive to promote energy efficiency measures, which reduce sales.

There have been many problems in implementing these proposals. First, utilities become neutral to the impact of sales levels and change rates to make it come out even, which passes on risk to customers. Second, caps reduce utilities' incentives to provide quality service. Third, they may undermine economic development activities that boost the regional economy. Finally,

they are very complicated and expensive to administer.

Maine adopted a trial program for Central Maine Power in 1991, but shortly after it was put into place, a recession occurred and revenue dropped significantly. This led to substantial deferrals, which actually shielded the company against risk that it would have borne otherwise, and after a few years the program was cancelled.

Washington also experimented with a combined decoupling and power cost adjustment mechanism for Puget Power, which led to several deferrals. The mechanism was cancelled after four years, and the Commission observed that the program did not give the company incentives to manage power costs or resource acquisitions at the lowest cost.

Promoting energy efficiency is good policy, but there may be ways to do it through utilities without decoupling. We are asking electric utilities to sell energy and also to sell the non-use of energy within the same organizational structure, and that is a fundamental conflict that creates unintended consequences.

Some states are trying a model under which utilities sell energy and other entities sell or promote conservation programs. Instead of decoupling revenues from sales, you decouple product sales from the promotion of conservation. Both entities are more proficient and cost-effective, and each profits by excelling in its core business. It also minimizes the need for regulatory oversight, since there are no sales adjustments or decouplings, and utilities can benefit from increased use of their product.

If we pursue decoupling and rate adjustments, it is important to do them by rate class, for equity reasons and to avoid discouraging economic development. Residential, commercial and industrial customers are quite different, and a global adjustment mechanism is not appropriate. There also should be limits on allowable percentage increases and the amount that could be accrued without triggering a comprehensive review of the utility's cost and revenue structure, as well as limits on the number and scope of other adjustments mechanisms that are allowed so that utilities have incentives to keep costs down.

Speaker Three

My company was the first utility in California to propose a revenue adjustment mechanism for electricity, in 1982. Today we have one for the distribution function and another for generation, excluding fuel. We go through a rate case with a cost of service/rate of return kind of approach for generation and distribution, take the result as our authorized revenue requirement, and set rates initially based on sales forecasts to recover that revenue. Base revenues cover O&M, energy expenses, plant-related costs, depreciation, taxes, and return.

We record deviations between billed revenue and the monthly adopted revenue requirement. If we collect \$1 million less than the revenue requirement, we record that sum as receivable. If we over-collect by that amount, we record it as a payable that ultimately will go back to customers. The balancing account effectively keeps

track of revenue differences due to sales forecasting errors.

Over the next ten years, we plan to save ten thousand gigawatt-hours through conservation, and to serve 60 percent of load growth through energy conservation. We could not do that by trying to constrain our output. The revenue adjustment mechanism removes the disincentive to push forward with conservation. It also creates budget certainty and makes it easier for us to experiment with rate design.

This system does not eliminate errors. Maine certainly seems to have based its program on a bad economic forecast if it missed a recession. It also requires more frequent rate cases – we go through them every three to four years. We can have rate volatility and strange impacts on cash flow, but this process has worked for us and our customers for some 20 years, and I think the Commission will maintain it.

Question: Can you quantify the impact of rate volatility?

Response: The average adjustment at this company, up or down, is about one-half of one percent, and I do not believe that there has ever been an adjustment greater than four percent.

Question: How have equity analysts reacted to this mechanism?

Response: They like the assurance. Having the revenue balancing account reduces the potential risks of rate design.

Speaker Four

If you think that it is important for the nation to pursue energy efficiency today, you have to recognize that electric and natural gas distribution companies face perfectly perverse incentives.

For example, the Idaho Power Company has an authorized fixed cost revenue requirement of about \$300 million, out of total revenues of about \$500 million. \$290 million of that \$300 million is recovered through variable energy and demand charges. If Idaho Power is going to try to save about one percent of system use a year through energy efficiency, it will lose about \$2.9 million in fixed cost recovery in the first year. This figure will compound every year after that, so that within five years, you rack up almost \$44 million in lost fixed cost recovery by successfully promoting energy efficiency. This is deadweight loss that will be suffered even if the company recovers every dollar that it invests in energy efficiency programs.

The solution is an annual true-up mechanism. Every year, you compare authorized fixed costs to what was actually recovered based on sales, and you true it up. In some years rates go up and in some they go down, but never by much either way if the mechanism is properly designed.

Some object that this policy removes an incentive to reduce costs, but under either a rate freeze or a revenue cap, the utility gets to keep the difference between the fixed cost revenue it is recovering and its actual costs. If the concern is losing incentives to promote economic development, you need a mechanism to adjust the fixed cost

revenue requirement between rate cases. We propose adjustments based on customer growth, so that the utility has a stake in building its customer base and promoting growth.

The key problem in the Maine case was that it was based on a very bad forecast going into a recession. In the Washington case, decoupling was connected to a much larger mechanism, and when it was eliminated, the Commission said it was not reaching a conclusion about the efficacy of the decoupling policy.

California has the most extensive experience in the nation with this approach (it was suspended during the unlamented period of 1997 through 2001), and it has made the nation's most effective investments in energy efficiency with no demonstrated record of significant rate fluctuations. California utilities all have revenue caps, soon to be supplemented by performance-based incentives for delivering more energy efficiency more cheaply. The IOUs are all pursuing energy efficiency on the electric side at least at the level of one percent of system load a year, and that target will accelerate in the next several years. They will acquire about 5,000 megawatts in efficiency and demand reduction over the next decade if these targets are met, at less than half the cost of alternative procurement.

Comment: A pure true-up may be simple, but if you start trying to adjust for weather, economic cycles, natural growth and kinds of use, it gets more complex, and can become controversial. Utilities may like these programs because they can shift risk to consumers,

but customers have a different perspective because they now have to bear the risk of volatility.

California is the only state that has a comprehensive decoupling mechanism, although others are looking at it. California has a greater affinity for energy efficiency and more tolerance for high rates than many other parts of the country. The issue is not whether to pursue energy efficiency, but who is best suited to deliver it – a utility with conflicting motives, or a third party.

Question: Does decoupling inherently promote energy efficiency, or do you need to have the state or regulators impose other policies?

Response: It removes the disincentive for utilities to promote energy efficiency, and in fact motivated utilities are critical to making those programs happen. They have the relationships with customers, they can mobilize a credible group of advocates, and they can work as partners with local governments and third-party providers.

Question: Are consumers frustrated when electricity bills fluctuate based on regular rate changes? How do you prevent cost shifts when some consumers can show that they are providing significant levels of efficiency or distributed generation, and get off of the system?

Response: Rates are already complex. We have five inverted tiers in California, and I don't think customers understand them at all. In terms of shifting costs, it is a matter of timing: if sales forecasts are accurate, they will capture migrations out, and if you do not get it in

the current rate case, you get it in the next one.

Response: We are talking about true-ups on the order of two percent or less, which is about five cents a day up or down for the average U.S. customer. I do not expect them to notice. Other so-called adjustments around the nation have been very controversial. Most dealt with fuel clauses, which are a routine part of regulation in many states.

Response: Cost shifting is a concern. Large industrial and institutional customers typically execute their own energy efficiency programs because they know their operations better than anyone else. They are concerned about being billed to fund other customers to take steps they have already taken.

Comment: As an economist, thinking about the fixed cost of the wires going to my house, I would say, bill me for the fixed costs of the wires plus a variable cost for every kilowatt-hour that I purchase, plus a tax for externalities like CO₂. But people hate fixed-charge bills, so you divide the fixed charge by the kilowatt-hours. And then you true it up, but you can't do it for each individual customer, so you do it by customer class. This would give essentially the right signals, and the true-up mechanism is exactly the right thing to do.

Response: In California, we can never get a customer charge put in, so you are right -- I need the mechanism to make certain that I collect fixed costs, because they are converted to a variable rate, which means that when conservation succeeds, I am short on recovery. But as a politician, you would have a problem with high fixed costs that produce high

minimum bills. There are many conflicting pressures that pull in different directions.

Response: Moving toward larger fixed costs is good policy, maybe starting with smaller fixed costs, because it sends a stronger signal to customers. But I maintain that customers have stronger incentives for conserving fuel, so they should be the focus. There is a question as to whether true-ups are too complex to be worth the effort.

Response: It is not complex for my company. Any deviation from sales forecasts comes out in the wash. That approach may insulate the utility from risk. Regulators set the rate of return based on their assessment of how to monetize that risk.

Comment: DRAM charges can be substantial for large industrial and commercial customers. Some Northeast companies were saddled with charges in the hundreds of thousands of dollars per year in the early 1990s.

Response: The cost of the Schwarzenegger program will be about three mills per kilowatt-hour for the entire program. This is not insignificant, but it is well worth the benefits that will be delivered.

Response: Residential customers in California are paying thirteen cents a kilowatt-hour. For semi-industrial customers in areas with lower rates, three mills is a lot of money.

Response: If we are doing this as a system resource, we should recognize that all customers on the system share in

the cost of all the resources that serve the system.

Question: Do utilities bear any risk in these programs? If not, could they at least share the risk?

Response: The utility gets an authorized fixed cost revenue requirement, not a windfall. It gives away an upside but avoids a downside. It is not guaranteed a profit, just a return on fixed costs. If it does not control total costs, it will not earn returns for shareholders.

Question: Does this system eliminate fuel adjustment charges?

Response: No. I get dollar for dollar recovery of fuel as the Commission allows, and I get the fixed costs the Commission adopted. I am still subject to oversight for performance and quality of service.

Question: How do you know what portion of a revenue deficiency is actually due to effective conservation programs, as opposed to economic cycles, weather problems, or the exit of industrial customers? Do revenue caps socialize more risks than we intend to socialize?

Response: Trying to understand all of the various factors that contribute to a disparity between actual recovery and authorized recovery with certainty would be a bureaucratic, adversarial mess.

Response: We are only paying for the difference between actual retail sales and forecast retail sales. If the utility's costs are out of control, that is deadweight loss, as it should be. All that the mechanism does is correct for

fluctuations in sales that were unexpected when the regulators set the rates.

Response: If you want to provide an incentive to retain customers, make the fixed cost revenue requirement depend in part on customer count. Increases in sales are a poor proxy for customer satisfaction.

Question: Does this approach encourage or discourage utilities from working more effectively with customers?

Response: The retail business should be about better-quality energy services. Decoupling removes the commodity orientation from the company's financial health calculus and encourages the utility to think of itself more as a service company, at least at the retail level. The product is not electricity and gas, it's better energy services.

Question: Can we use this approach in a competitive model?

Response: Seven or eight states have developed separate entities that are charged with implementing demand-side management activities. They can go out and competitively source contracts. The Oregon Energy Trust collects three percent a year on customer revenue to fund efficiency programs.

Question: If you have retail competition, do you need revenue caps? Do they work together?

Response: The market was supposed to provide energy efficiency through

providers who were motivated to give good service to customers, which could have both efficiency and commodity dimensions. It has not delivered something comparable to the proven models in California or Oregon.

Comment: My company is a large retail supplier to commercial industrial customers, and we are seeing a lot of interest from them in energy cost management. It is more predominant in market where customers see real prices and prices that are tied to markets on a variable basis. There is also interest when customers believe that savings from DSM and curtailment programs can be sold back into the system and counted toward some of the goals we're trying to reach with resource adequacy requirements. It is a perspective that is concentrated among commercial industrial customers and in states that have good retail access programs.

Question: What role should FERC play in trying to achieve these ends?

Response: Most of the fixed costs that we're discussing are incurred under state regulation, so this issue is primarily one for state regulators. But it is important for FERC to stress demand-side solutions. The electric and gas industries are under massive pressure now, which is creating price volatility. It is very heartening to see FERC urge grid managers to promote demand-side resources on equal terms with supply-side resources to achieve resource adequacy and enhance reliability.

Session Three: Revisiting Open Access: Groundhog Day Again

At the turn of a new Federal Administration and new Congress, frustration with electricity restructuring raised anew calls for abandoning the effort, fixing what is broken, or declaring victory. (See FERC, CMU, NRECA, CATO, CAEM, APPA papers and statements, and more.) At its core, the debate identifies persistent disagreement about what open access means, and what models are available to achieve the purported benefits. Reform of reform is a common theme of the growing string of acronyms: EPAct—OATT—OASIS—CRT—TLR—ISO—PJM(97)—ISONE(98)—CAISO(99)—RTO—SMD—WMP—???. Market-based pricing authority review may indirectly extend the string. Under the conceptual umbrella of revisiting the ideas of open access and Order 888, one appeal is to consider alternatives to the recent FERC policies regarding RTOs: "... it should not be assumed that RTOs are the only, or even the preferred, mechanism available to ensure competitive wholesale power markets." However, as the string of acronyms suggests, alternative models have been proposed, analyzed and tested. What is the innovative alternative model that would implement open access? How would it be different in practice? How much of market design flows from the principles of open access and how much is optional and could vary by region? To what extent is the debate more about the principles than their implementation? What should be the policy direction for the reform of the reforms?

Speaker One

The Eastern Interconnection is a 600,000 megawatt synchronized motor. If we were going to create that system for the 21st century, we would not run it by having two countries, eight provinces, 32 states, and 3,200 different entities involved with generation, transmission and distribution, with some entities regulated by FERC, some regulated by states, and some not regulated at all. The electric grid is trying today to evolve from a system run on an engineering basis to one run on efficiency principles.

In 1992, when we were considering forming PJM, several states estimated that by operating as a tight power pool, we were saving over \$1 billion a year. We had eight companies in five states and the District of Columbia operating as one with perfect dispatch. We

dispatched every single unit, we knew heat rates and fuel costs, and this was audited every hour.

The question is whether you can do better using market principles and market forces. Today in PJM we have over 400 members. We serve over 50 million people with a peak load just over 127,000 megawatts. We have 161,000 megawatts of installed capacity from nearly 1,100 generation sources, and 165,000 square miles of territory. Moody's recently cited PJM as a stabilizer for the region.

Some critics argue that RTOs cost too much, but we reduced our costs by 25 percent in 2004 to a year-end cost of 39 cents a megawatt-hour while we were growing and expanding the grid. We have added over 13,000 megawatts of generation, largely driven by merchant facilities. We have made over \$1 billion in transmission investments.

When new plants come into the grid, they have to pay for the upgrades that are required so that they can deliver power throughout the network. This makes the grid stronger every time a new generator comes on. The forced outage rate has dropped from ten percent under perfect pool dispatch to five percent under competition. Installed reserve margin has dropped from 18 to 15 percent, which produces major savings.

Our dispatch system is open: prices are published and anyone can bid and participate. We have transparent prices, market price liquidity, economies of scale, and a planning protocol that people can trust.

RTOs are not the only solution, but we have eight years of history operating the world's largest single grid and doing it with competitive markets. If there is a better model, we would like to see it.

Speaker Two

It is legitimate to ask whether RTOs are the only mechanism, or even the preferred one, to ensure competitive wholesale power markets. However, it should not be assumed that they are *not* the only solution or the preferred solution. The burden of proof is on those who think that there is an alternative.

The critical monopoly that we need to examine is transmission – not really the wires and ownership of the wires, but the operation of the system and application of the rules.

At its root, this discussion asks what Order 888 anticipated for the development of electricity market design. Did FERC jump too soon to an RTO model with a standard market design that forecloses other options, and what other models are available to achieve the goal of open access under Order 888?

We often see a false dichotomy that poses a choice between a regulated monopoly, vertically integrated system or an unregulated monopoly system. I believe that there is a middle ground, which is characterized by the capacity reservation tariff and its descendants – the RTO, the standard market design, and the wholesale market platform.

Another false dichotomy is the notion of separating transmission and energy, with a transmission operator and a separate energy market run by the power exchange. In real time, you cannot have separate decisions on how to get energy and how to use transmission. They are the same decision because of the nature of the grid, so it is critical to make sure that those things work together.

Many people think about market design starting with investments, then moving to scheduling, then to plant operation, then to dispatch. So they develop rules for investments, then for commitments, then for scheduling. This approach is backwards. Design should start with the real time balancing or gross pool or net pool market, get those rules right and then work backward.

If you do that, you discover that the components of successful market design include the core elements of the FERC standard market design and the

subsequent wholesale market platform. First, efficient real time operations conform to economic dispatch, and the prices or opportunity costs at the margin are equal to the locational marginal prices. Any other outcome will require intrusive mandates and rules to maintain reliability and achieve efficiency, because without efficient dispatch and locational prices, by definition there is an arbitrage opportunity that people will try to exercise.

Second, ideas like available transmission capacity, which are at the core of the Order 888 contract path model and Order 889, are not well-defined in the sense of how the grid is actually going to be used. There is a fundamental conceptual problem: you cannot define the available transmission capacity until you decide how to use the grid, and if you use the idea of available transmission capacity to decide how to use the grid, you have a circular argument. By contrast, the point-to-point FTRs found in SMD provide an alternative, well-defined and workable set of rights to support forward markets.

Third, security limits dictated by reliability standards are implemented as contingency constraints, which inherently require coordination and simultaneous evaluation. You have to go through extensive calculations, not just observation.

Fourth, bid-based dispatch or balancing systems can incorporate the elements needed for efficient operations to support coordination and competition. The system does not have to be cost-based – people can express preferences in their bids.

At the center of all of these issues is the spot market run by the RTO, a security-constrained economic dispatch with nodal prices. This centerpiece is the successful market design.

Critics of this approach always offer vague alternatives. We have tried different ways of defining transmission capacity, such as contract paths, flow-based bit models, and point-to-point variance. Zonal models are common, but they have failed in PJM, in New England, and in California. There is a mindset that the successful market design is too hard, but in fact, every other approach is harder, and this is the simple way to approach the problem.

The core elements of successful market design are necessary but not sufficient, and there are many remaining tasks, including better demand response, scarcity pricing, seams across the integrated grid, transmission investment, resource adequacy, and long-term incentives for RTOs.

Speaker Three

Public power companies are state and local utilities. There are more than 2,000 of us, small and large, inside and outside of RTOS. We serve 14 percent of the nation's electric customers.

Our model is different from many utilities, especially in states with retail access. We believe in local ownership and local control, and we are not for profit. Our goal is to provide reliable service at reasonable rates, consistent with environmental stewardship.

Our systems are vertically integrated: some companies own their own

transmission and generation, some are vertically integrated by contract. Many of the smaller companies have formed joint action agencies, which are statewide agencies that provide power and transmission for them in wholesale markets. So we purchase about 70 percent of our power in the wholesale market, and we use other entities' transmission systems frequently. We have major stakes in the terms and conditions of transmission service and in the health of wholesale power markets.

Our orientation is conservative, infrastructure-based, and long-term. We seek to maintain portfolios of assets and contracts that will support our service over 20- to 30-year periods, and this model has worked well for us.

We were strong and early supporters of FERC's open access transmission policies, because we thought they would ensure non-discriminatory transmission service. We wanted to eliminate pancaked transmission rates because we found that a lot of deals from systems one or two systems away were uneconomic because of transmission rate adders. And we saw ISOs as platforms to facilitate regional transmission planning and construction.

We believe that in the implementation of open access, these original goals have been subordinated to the development of centralized RTO-run markets. In some ways, locational marginal pricing has replicated the pancaked transmission rates that we saw earlier, and unless we have sufficient transmission hedge to cover it, the rate differentials can be just as deal-destroying as they were before open access. Finally, we have become

alarmed by what I call no-generator-left-behind pricing policies.

Today, public power companies in RTO regions are unhappy to be there, and those not in RTO regions are happy not to be there. This is exactly the opposite of what we expected as advocates of ISO and RTO formation.

Our members in RTO regions are upset about spiraling costs, unaccountable governance, lack of understanding of transmission customer and end-user needs, and unsatisfactory service options. We see RTO services being provided through questionable market mechanisms and RTO resistance to any questions about the economic theories that underpin these actions.

Our specific problems include lack of long-term transmission rights. We need to know the cost of transmission service for long periods of time, which is not really possible under the current system and is hindering our participation in new units.

We are concerned about the need for new transmission construction. Some RTOS tend to pigeon-hole upgrades into projects needed for reliability versus those needed for economic reasons, and to leave the second category to the market.

RTOs need to develop rigorous regional transmission planning and construction processes that assure their regions will have robust but not gold-plated transmission systems. We think they should encourage joint participation by other utilities serving load in the same region, which would spread the financial burden and the perceived investment

risks. Many public power companies would be interested in buying into existing shares of the transmission system and helping to finance new construction, if they received assured long-term rights in return.

Our companies are alarmed by rising RTO development and operating costs, and by the costs to members of dealing with RTOs. We have had to ramp up internal operations and add staff, hardware, software, and back room functions just to keep up with RTO processes. FERC recently issued a Notice of Inquiry on RTO costs and accounting, and the Commission may expand this docket to address cost containment and accountability.

On the issue of RTO governance, we originally supported independent boards, but have found that some boards are not accountable to anyone. This creates the perception that RTOs have only one dominant stakeholder, which is FERC.

In regions that do not have RTOs, we think that there are workable options that will deliver 80 percent of the benefits of RTOs at 20 percent of the cost. One example is the westTrans.net Open Access Same-time Information System (OASIS) site, where 20 western utilities post available transmission capacity and prospective customers can submit a single electronic query for transmission service over multiple systems. Regional cooperation on transmission planning and construction is an important advance and should be encouraged.

It is too late to go back to traditional cost-of-service regulation, but we need to analyze what works in the real world, so that we can find ways to get

infrastructure built at reasonable costs in a reasonable period of time and mitigate market power. Less can be more.

Speaker Four

Thirty years ago, economists would have found two flaws in electricity markets. First, there were incentives for excess generation capacity, because utilities were paid more for investing more. Second, prices for electricity were always wrong – too low on peak and too high off peak – and sent very imperfect signals to consumers.

Today, what have we achieved as a result of restructuring? No one has mentioned ICAP here, but if we are socializing the costs of excess capacity, that looks a lot like the old system.

The hardest question for me is why power costs are lowest in regulated states. To answer that question, you need to distinguish wealth redistribution issues from efficiency issues. Because standard regulated states have weighted average pricing, the cost of infra-marginal generators matters in the prices to final consumers. That is not true in any free market that I know. Infra-marginal producers in an industry that has an upward-sloping supply curve get rents, but those rents are suppressed in the traditional cost of service rate regulation model.

So when I see prices like 4.3 cents a kilowatt-hour in Kentucky and 12 or 13 cents in California or New York, I see a difference in their infra-marginal fuel mixes. In particular, I see the influence of the Clean Air Act: we have old coal-fired power plants that are under old source standards, and in a free market,

those plants would get rents. But those rents are suppressed by rate regulation, and then redistributed to consumer groups.

In a true laissez-faire world, there would not be price differences like these across states if natural gas was the marginal source in every state. But in a cost of service world, there are differences, and opening up the market involves lots of wealth redistribution that the regulated states want to resist.

If people want to trade voluntarily, locational marginal pricing is the right answer because it sends the correct price signals. The puzzle for me as a political economist is, why is there resistance to change? I think the answer is that wealth redistribution is taking place. But if I am right, why did utilities resist change? They would be richer in a free market because one-time capital gains would accrue to those infra-marginal assets. I believe that after 70 years of regulation, utility executives are not very entrepreneurial.

There would also be gains from trade through changes in the transmission system that would result in lower prices at peak times, particularly in the summer. A welfare-optimizing operator should be able to bribe all of the existing states and owners to give up their control over the system in return for a pro-rated hunk of surplus from the gains to trade that could accrue under a standard market design-RTO type of system.

Locational marginal pricing gives the correct static efficiency answer for how to run an electricity system, but I have never been able to figure out how to cycle back the existence of transmission

rents and various links in the system into optimal investment in the future. It is very difficult to think through whether the decentralized actions of generators and transmission investors could somehow create dynamic efficiency.

I am not a regulation supporter, but vertical integration may be an optimal industrial organization that we are ripping up and trying to force to do things, when maybe it was the least cost solution to all of these issues after all.

If forcing wholesale generation competition onto a regulated transmission and distribution system is difficult, then can we conceive of vertically integrated utilities that still compete in some way? We might think of natural gas pipelines as completing with electric transmission systems, and on the coal side railroads could be viewed as a fuel source. We could either burn these fuels close to urban load, or have generation take place far away and ship the product on electricity transmission lines.

Speaker Five

I believe that competition is the right policy in wholesale markets, and that the debate is over means. As Jay Morrison recently wrote in the *Electricity Journal*, there are three competing visions of the ideal structure of the electricity industry:

- Traditionalists support pre-Energy Policy Act structure and believe that vertical integration can best deliver reliable power at reasonable cost.
- Open access advocates supported EPAct, orders 888 and

889, and voluntary development of ISOs and RTOs.

- Market advocates support key elements of SMD, including standardized centralized markets and LMP.

Open access and market advocates both believe that competition can lower wholesale power costs, and both support wholesale competition, but they disagree on how to achieve that end. Traditionalists reject or minimize the role of competition in electricity markets.

One distinction between open access and market advocates is on the role of federal electricity policy. Market advocates believe that federal policy should focus on promoting efficiency; open access advocates believe that federal policy should focus on preventing undue discrimination rather than on promoting efficiency.

The choice is really between the open access and market advocate views. It is clear now that the SMD NOPR will not be finalized, although it may be voluntarily adopted by RTOs. That reflects political reality. The Commission is not immune from political pressure, and if it were to finalize the SMD proposal, Congress would probably overturn it.

Therefore, the Commission should focus on the open access vision, including reform of Order 888. Our tools to remedy undue discrimination are stronger than our tools to promote efficiency.

I support voluntary RTO formation to promote competition, but it is not the only means. And I agree that we have

not responded well to concerns about RTO costs. The RTOs also have to do better at emphasizing the benefits that they have achieved to date.

We should consider stakeholder boards, or hybrid boards, particularly in areas where RTO costs are perceived to be out of control. RTOs cannot be self-regulating.

Comment: All hybrid boards have failed. Ultimately, stakeholders have the most leverage. They elect the board, and if their needs are not met, they should vote out the board members and put in new ones.

We do need to look at long-term FTRs. You can get FTRs for four to five years in PJM, but public power companies' needs are cogent and real, and we should address that issue.

Question: What is the metric for measuring undue discrimination? Suppose you can demonstrate that it costs more to the end user in an RTO to operate a fully open-access competitive system. If an alternative – which I would describe as traditional retail regulation as determined by the states, with native load preference for utilities – costs less, would it be undue discrimination to give IPPs or others fewer rights than utilities?

Response: Municipal and cooperative entities serve load too. If you decide that it costs too much to give them access to the system, does that mean that it is acceptable to curtail service to 25 percent of customers to serve the other 75 percent? It is part of our federal system to make certain that all customers are served on reasonably comparable

terms and conditions, and that means not favoring one class of customers unduly over others.

Comment: In the Northeast, we have had \$50 to \$60 billion worth of private investment in new generation. Some of these investments were bad, but companies bore the risk instead of ratepayers. If it had been done on a cost-plus basis, it might have cost \$70 to 80 billion. And our outage rates have declined dramatically with competition. This is an overlooked benefit from deregulation.

Response: The costs are borne somewhere. They may be born by investors in plants, but they also make the whole system riskier when excess generation drives companies into bankruptcy.

Question: How do you do regional planning when the people in charge do not have the ability to decide where generation will locate? In regions without RTOs, there are no price signals telling those generators where or when to build. Second, can you have efficient competition in wholesale markets when purchasers do not face the true costs of their decisions? If the cost of transmission is rolled in so that the only true cost the purchaser sees is for generation, isn't that going to result in inefficient competition, which is what we're trying to preclude by moving to RTOs and LMP markets?

Response: Regional planning should involve state commissions from the outset and urge them to work with all of the generators and load-serving entities in the region. If you make people's market-based rate authority contingent

on engaging in such a process, it would get their attention.

On pricing, you are absolutely right. Regional flexibility is part of the answer. In New England, most transmission additions above 115 KV are rolled in for the whole region, whereas PJM requires that the generator who is hooking up pays associated costs unless they are required for reliability. SPP has a hybrid method that is essentially a middle ground between these approaches.

Response: Today, transmission is a privately provided public good. Everybody wants it to exist and no one wants to pay for it. You surmount that through contracts in which I agree to pay two-thirds and you agree to do one-third. All of these allocations are arbitrary – there is no economic answer as to who should pay for the public good.

Question: What about cost causation? We know what that means.

Response: No, we do not. That is the problem. If you take that approach, and we have to look at every stick of new transmission and figure out who benefits from it and make them pay for it, people will eventually get tired of paying for a license plate with layers on top of that, and they will want to open up the license plate and look at everything.

Comment: A large part of the costs associated with our ISO are stakeholder-driven. Everyone wants their issues addressed right now. I spent an inordinate amount of time as Chair of my ISO making peace treaties between municipal utilities and the IOUs, and all of that costs money.

Question: Without some form of RTO, how do you address the problem that the transmission system owner will use the system to discriminate against others in the market, producing sub-optimal economic efficiency?

Response: Again, I want to distinguish who gets the rents from efficiency. You could view the allocation of rents between generators and transmission providers as economically arbitrary. I would resolve that issue by contract, whereas you guys are all going to the political system to settle it.

Response: You are paraphrasing the Coase Theorem, which is certainly right if there are no transaction costs and property rights are identified and obvious in advance and assigned to someone. But we are talking about a system with enormous transaction costs and undefined property rights. The successful market design is intended to make property rights clear and assign them in such a way that they can in fact be implemented. There are different solutions in different regions for the contentious issue of who gets the rents, but we cannot avoid the step of defining the property rights.

Question: Are public power companies satisfied with contract path property rights?

Response: No, but the issue is what they think can realistically help them. Companies located in regions that have already gone to a full Day Two market are interested in bettering their conditions within the existing framework. Those who have not yet gone there are not ready to give up physical rights.

Question: Cooperatives strongly supported wholesale competition, because we buy a lot of power in the marketplace. But I think we are trying to accomplish different things when we talk about trading. There is a short-term focus on efficient trading, and a much longer-term focus on wholesale competition, not competitive markets, where consumers benefit in the long run from stable prices. Are we talking about a timing difference here?

Response: There is a temporal issue, but I would argue that you have to worry about both short-term and long-term markets. Resolving the short-term issue is harder, and once you get it right, the long-term challenge becomes easier. FTRs were developed to answer the legitimate question of how to design something that will allow power to be delivered through the grid over many years when physical rights are not possible for everyone. They were not promoted initially as a trading idea, but they are compatible with trading. They define property rights in a workable way, and then you can trade them too.

Response: Some public power companies are finding that wholesale power marketers are unwilling to enter into long-term contracts at reasonable rates when they can sell into day-ahead markets and get a clearing price based on a higher-cost fuel. That is leading them to build their own generation, which poses the least risk for a not-for-profit, lowest-cost provider. It is interesting and sad, since the wholesale power market and open access were supposed to open up new supply options that we could take advantage of.

Comment: In politics, people tend to oversell the benefits of getting prices right.

Comment: As a state regulator, I worry about independent RTO boards, but I am less concerned about them than about stakeholder boards made up of utilities and transmission owners with direct financial interests in the RTO's decisions. If FERC is going to look at this, it should consider what is good for consumers, not just for stakeholders.

Response: I think we should consider hybrid boards, with perhaps a minority made up of stakeholders, in areas where there are concerns about cost escalation. I am also looking for other ways for us to regulate RTO costs more effectively. We currently review ISO-New England's budget, and maybe that should be a requirement for all RTOs.

Response: RTO boards mainly discuss market information, plus some personnel issues. Stakeholders would have to recuse themselves from most board activities. That is what happened in Ontario with their hybrid board.

Response: Public power companies want to refocus RTO boards on what will best serve consumers. One option would be stakeholder advisory committees who

can participate in board meetings or parts of board meetings. We are also concerned about self-perpetuating boards, and I agree that selection is the way to get that message across.

Comment: When I worked in the Southeast fifteen years ago, we had a diverse industry – municipals, IOUs, some owning transmission and operating control areas, some who didn't. Companies that did not own transmission or have control area service rights had to go and seek out that market, and they chafed under the master who had the control rights and the control area. We formatted many different methods, like pseudo-control areas, that mimicked what a market would be able to do. We are all still just trying to figure out the value of getting power from point A to point B, and what that ancillary service should cost.

Response: I agree, and the real issue for our members in the Southeast is trying to get more options and ability to move. And that's that.