Harvard Electricity Policy Group
Thirty-Second Plenary Session

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RAPPORTEUR'S SUMMARY*

Session One: Setting the Standard for Standard Offers

Many states made provisions for standard offer service as part of electricity restructuring. There were initial periods and terms of the service. Most service providers contracted for the requisite energy. Some incumbent utilities, divesting themselves of generation, entered into supply contracts with purchasers as part of the condition of sale. A number of states set the standard offer rates to decline (or at least not increase). Now that the initial periods are expiring, many state regulators and legislators are revisiting the issue. The option of linking supply contracts to plant sales is no longer available. The number of suppliers is decreasing; many of the existing contracts are below market; gas prices are increasing; and retail competition for residential and small customers has not taken hold in most places. How much volatility will consumers tolerate? Must regulators provide price stability, or can rates float with the market? How much regulatory intervention to socialize risks is needed? Are there market-based alternatives to regulatory intervention? Should regulators contemplate more dramatic measures such as regulatory "slamming?" Should we bifurcate the market between core and non-core customers? What limits, if any, should be placed on the ability of consumers to cherry pick between standard offers and competitive supply? Are such limitations sustainable?

Speaker One

Opening California's marketplace began with legislation known as AB-1890 in the summer of 1996. Through 1997, California was forming a market for April 1, 1998, when direct access was opened to all bundled customers. But throughout this process, rates were capped by the three IOUs. At the same time, revenue cycle unbundling occurred. Initially, there were three billing options for direct access customers: a spreadsheet-consolidated bill; a utility-consolidated bill and dual billing. At the height of direct access in 1999, about 40 percent chose the ESP

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option; 20 percent the utility option and 40 Percent dual billing. Today there are no ESP billing options; 20 percent use utility consolidation and 80 percent receive a consolidated bill. Also at the height of access, the energy crisis began. In June 2000, the state legislature recapped SDG&E's rates at six-and-a-half cents per kWh. Into winter 2001, ESPs began to shed customers returning primarily for bundled service.

In February 2001 the legislature passed a bill allowing California to buy power for the utilities. The legislature also indicated that direct access would be suspended; the California PUC would determine the rules of that suspension. As the formal suspension date of September 20, 2001 drew close there was a lot of direct access activity. When the PUC became active, I think it put a chilling effect on some of the ESPs, primarily in the residential market because of a few, well-publicized consumer protection stories.

It is also important to look at the politics because the legislative process today more than ever before, influences the regulatory process. In the last session, two efforts to reinstate direct access did not pass. A senate bill to re-regulate the industry also failed to pass.

Current direct access customers can switch between ESPs and relocate their direct access service to new locations. During the suspension, they may switch between direct access service and the utility, with temporary turns limited to 60 days, and if they return to utility service, it is at a short-term commodity rate. Longer terms require a three-year commitment. New load customers on direct access may be eligible for direct access during suspension. Customers who did not elect direct access until after February 1, 2001 must pay a share of the cost of the long-term contracts that were entered into by California. The current rate is 2.7 cents per kWh.

The PUC has the dual responsibilities of not harming or making the bundled customer indifferent, while also having some viability of direct access. As a new legislative session begins in late January 2004, I suspect that re-regulation and reinstatement of direct access will be back on the agenda. I hope the PUC will play a greater role. Perhaps it will begin to look at a different marketplace than the one being contemplated by the legislature. And given the blackout in the northeastern states, perhaps California will get some objective thought going forward.

Speaker Two

The ways to categorize the existing structure for a provider-of-last-resort (POLR) range from no backstop to regulated utility provider. Another is a market index with a pass-through price to customers, which means that they are really on a spot market or other variable basis. Eastern states have seen auctions or bid models for POLR service; while in Texas a regulated body sets the rate for the utility affiliate that provides the backstop service separately. There are also options in which the regulated utility is the backstop and is the sole determinant of how it gets generation, whether from its own sources or by bidding out. In states with good structures, like Massachusetts and New Jersey, the results are good, particularly for commercial and industrial customers.

What can we accomplish to move residential customers to a competitive model? Or is the goal to make sure they have supply at a certain rate, and competition or choice is secondary? Despite the lower switching rates for the residential and smaller commercial market, I believe that smaller customers are benefiting from restructuring. Competitively procured generation leads to more efficient pricing and less stranded cost. Where utilities go out to bid for generation, competition really allows for more efficient pricing to come through on a wholesale basis to the utilities that provide that service. It also reduces the opportunity for stranded costs for the utility to be engaged in generation or to construct new generation. The likelihood of increased stranded costs on the generation side is far less under this model.

Restructuring has also moved much of the investment risk concerning generation to the shareholders. Finally, to the extent that commercial industrial customers benefit from cost savings and more efficiencies in the market, society benefits as a whole. This is hard to quantify, but more efficiencies on your energy bill allow you to make other investments, employ people and so forth.

The competitive bid generation models in Maine and Massachusetts lend themselves to more efficiencies and choice, where customer groups divide bids, and pricing is set on a different basis for those groups. When load is bid at different times, it seems to lead to better pricing for customers.

The credit requirements for bidders have become an increased concern. It is a fine balance, recognizing that concern and still having enough market players to achieve efficient pricing. Confidentiality of the auctions and bids are also important. Several states are also looking at whether bids should be wholesale or retail. In a retail model, the bidding entity that wins would have a direct contract with the end-use customers and thus be more responsible to them.

Another important component is price variability. From an economic and efficiency perspective, price caps do not work in terms of trying to build new generation or in encouraging efficient behavior. I argue that some variability is necessary so that prices actually reflect what happens in the market. Monthly or seasonal differentiation is ideal because it helps minimize the migration risks associated with the cost. It also minimizes potential for under-recovery and cost deferrals.

Some challenges we face include how to address small customers who do need a backstop service, probably with less variability from a pricing perspective than commercial industrial customers have. The most challenging is the core-non-core debate: which customers are on which service? I think that depends on the market development in a region and on the rate structure of specific utilities. I do not think there is an easy answer. It is also dangerous to include a cut-off point in legislation. A cut-off can be so firmly in place that it sets the market without opportunity to change, should experience warrant that. Yet another challenge is the increased demand by generators to return to long-term contracts and the policymakers' desire to increase capacity. Generators do not consider bids for six months or two years sufficient to pay for current facilities or build new ones.

If we had rule certainty about our models, about the bids ten years out and how all of this will work together, it would alleviate the existing anxiety. Maybe we need to educate the financial world about why the energy market is more efficient and generators more successful if contracts are two-five years, as opposed to fifteen-twenty years in length. For an LSE, it is most efficient to go to the market and purchase the things that will best meet its portfolio requirements, hedges and options. This makes the market more dynamic for everyone.

Speaker Three

From a commission's point of view, there are many political implications involved with standard offer that raise more questions than commissioners have answers. The standard service offer I discuss is the price, not just POLR. In Ohio, it is thought of as the bundled, frozen rate. When restructuring was developed, the frozen, bundled rate had to carry with it an immediate five-percent discount to the generation rate. It was for residential ratepayers and immediately caused some angst among those who thought that it would reduce the headroom that would be available for those who chose to compete in the market. Where shopping credits do not work there is market support generation – generation set side for the purpose of handing off a certain level of discounted generation to wholesalers. Competitive retail electric suppliers (CRES) are certified by Ohio's commission. The biggest daily battle is between marketers who are looking for whatever margin they can get and the EDUs that otherwise supply the power.

When the POLR rate thaws, it may be that many customers will be thrown back on the EDU, if a CRES chooses to leave the market. When and if customers do leave their CRES, a variable rate would minimize the impact on other marketers who are still in the game. This variable rate could be provided by the EDU in the form of standard service offer, as the highest marginal cost of whatever is produced at the time. It more accurately reflects the EDU's obligation to supply the customers who it had not counted on providing prior to this point. If the commission sets the backstop too high, marketers will argue that it will be impossible to get anyone to switch.

Aggregated customers can be a huge political problem. Ohio has the largest residential aggregation in the country – over 120 communities. Try sitting down with 120 mayors and city managers to tell them that there may be a problem with switching back after you worked to include an opt-out provision.

It is obvious that the wholesale market has not developed as expected in 2001. At the end of this market development period, we cannot expect anything better to happen. Market support for generation has been set aside because some of the retailers will have gone. Shopping credits will be gone. No one knows if formulas, auctions and an RFO will work. We do know that rate shock is not an option.

Ohio's rate stabilization program uses a workable price to which is added a certainty premium, or multiplier, that represents the costs of hedging. There are some exogenous adjustments as a result of compliance with air quality standards and this gives us the market-fixed, standard service offer. We expect customers that did not switch to pay this. Still to be determined is a POLR rate for those who switched.

These are some of the issues that commissions must address. It represents the reality that other states are up against. We look forward to arriving at agreements before the market development period ends.

Question: Would you define the level of price differential before the period ends as rate shock?

Response: Some people may call it variability. Sometimes rate shock may be better because variability implies uncertainty. Rates that vary significantly can be somewhat scary for many people. Since states usually go rate case by rate case, so I do not know what constitutes the kind of variance that would indicate a rate shock.

Question: How many CRES are left in Ohio?

Response: Four or five in the north, none in the central part and one or two in the south.

Speaker Four

Massachusetts offers standard offer (SO), or default service, as it is called in other states. The state's restructuring legislation passed in November 1997, and retail customer choice began March 1, 1998. There was a mandatory rate reduction off of the all-in prices for electricity. The transition period ends March 5, 2005, when all customers become default service customers. SO has a predetermined rate discount and is available only to customers of record on March 1, 1998. Once you switch, you cannot go back.

Default service is a market rate that results from competitive procurement, which the commission defines as the result of the RFPs that distribution companies issue for service. Prices for SO were predetermined according to the settlement agreements that were filed prior to passage of the legislation. The agreements provide for adjustments for extraordinary changes in fuel prices.

The state statute was designed so that SO service ratcheted up over seven years at the same time that the wholesale price would come down, and eventually the two would cross. At that point, people were expected to switch to default service. That did not occur.

Beginning in spring 2000, the wholesale price began to edge up, mostly due to fuel, but there was no adjustment in either the SO or the default service price. At the end of 2000 when Massachusetts de-linked default service prices form SO prices and established the new procurement level prices for default service, it also hit the fuel trigger for SO service. Next, the wholesale price edged down again as fuel prices declined, but the rolling average of the fuel trigger for SO did not keep up. Returning to the predetermined schedule of prices did not last long because the trigger was hit again. In fact, those lines that were projected to cross may now do it in the last year of the transition period. Since 1999, there has been very slow movement of the residential market to competition. But it is mostly the large customers who have switched.

The Massachusetts commission did not spend a lot of time on policies for SO service, given that the price schedule was predetermined and SO was set below the wholesale price. Commissioners focused on default service because that is where the opportunities lay and because it is the service that survives the transition. Its first order on default service was issued June 2000: prices would vary by customer class; the two options offered were a monthly variable price and a fixed six-month price that is the average of the monthly variable price. Companies go out for a six-month procurement and ask for a price for the following six months so that the price for each of the months ahead is known in advance. There is also an anti-gaming provision to prevent customers from gaming the averaging aspect of the six-month option.

The June 2000 order said that inclusion of administrative costs, such as bad debt, complying with regulatory requirements and complying with the state's renewable portfolio standard, would send the right price signal, but would have a de minimus effect. The administrative burdens outweighed the improvements in efficiency of including those costs. In April 2003, the commission decided that including these costs would not be negligible. It estimated .2 to .3 cents per kWh, which makes a big difference in a commodity market. Neither order included customer acquisition costs and indirect retail costs like customer service and billing.

Default service procurement terms have been a big issue. In April 2003 the commission changed to using contract terms of twelve-month contracts twice per year for 50 percent of the load to ease some of the volatility of a contract for 100 percent of the load at any given time. These procurements are staggered through the years so that all of the distribution companies are not in the market at the same time, to help with liquidity. Moving to monthly procurements would be best because it would remove the price certainty for the medium and large C&I market.

On March 1, 2003, New England began to operate with LMP. Every state except Massachusetts was one zone, except for Massachusetts, which was broken into three. The state also has two companies whose service territories cross the load zone. Should prices for customers differentiate, based on zone? The commission decided not to for residential and small commercial.

It is appropriate to have different policies for different customer groups. Should default service be a resting place for those between suppliers, or is it the primary source of supply for customers? In markets where customers are switching, the default service really is just a resting place. But for customers who are not or may not ever switch, default service may be their primary source of supply. In my opinion, the regulatory goal is to find the most efficient market structure that delivers the most benefits for customers.

It is equally bad to be holding prices below cost, as it is to artificially raise them above cost. We should be comfortable with the possibility that competitive wholesale markets and a pass-through of a utility-procured supply may represent the best outcome for mass-market customers. There has not been a real market test that retail customer choice can work for all customers because 75 percent of the customers in Massachusetts are on SO. You cannot therefore draw the conclusion that the market does not work.

If they do not exercise retail choice and default service becomes the primary source of supply, I think regulators will have to engage in portfolio management for default service. Would we replace the old regulated world of regulators doing prudence reviews on the capital investment decisions of vertically integrated utility companies with regulators reviewing the commodity market decisions of regulated companies?

Should a utility profit or be harmed? Now it is a straight pass-through and a reconciling cost mechanism. Should we make this an incentive regulation scheme? Is portfolio management an opportunity to resurrect integrated resource planning at the retail level? What is the optimal portfolio? Should procurement policies be managed to ensure the health of the generation sector in the wholesale market? If longer contracts are used, should large customers be restricted from switching if they choose default service? Larger customers have been willing to shift between default service and competitive supply, depending on the relationship of the market and the regulated price. If regulators adopt such policies, maybe there should be some restrictions on switching in the future.

Discussion

Question: What is long-term and what about overlapping contracts or dollar-cost averaging?

Response: Procurements may occur on a certain schedule. A competitive supplier may see such schedules from six months to two years, for example, which means that the pricing the customers see will be linked more closely to the current market, or that is the hope of the current forward curve. It matters to retail because the longer out you are the further you are from today's and tomorrow's current markets. The person who wins or puts in the bid bases it on today's forward curve, not tomorrow's. From the perspective of a wholesale supplier, there are risks the further out you go.

Question: If resource adequacy depends upon long-term contracts primarily to supply to the mass market, how much room is there for a wholesaler to supply the retail market with contracts of two-five years? Do we need to rely on long-term contracts for resource adequacy?

Response: We are beginning the debate about whether retail policies should be adopted. For the past few years, I think we assumed that healthy wholesale and capacity markets would be sufficient to ensure generation resource adequacy. What is happening now is largely a function of capital markets. Some generators say – and the capital markets are driving this -- we just need to focus on getting a creditworthy buyer in order to commit capital. I am hopeful that this is more of an overreaction to the past few years. As we talk about ten-, fifteen-, and twenty-year contracts for default service, we will have to look at pushbacks on the unrestricted ability of people to exercise choice.

Response: The generators' conversation is occurring at a time when there is over-capacity. Some generators are asking for money to ensure that the costs of their existing plants are covered; others want to build new capacity. I suggest that we should look more closely at the wholesale market to solve some of the existing capacity issues.

Comment: We use many terms like standard offer, default service and POLR to distinguish core and non-core. I think core is people without access to alternative suppliers, while non-core has access. The latter requires default, POLR or something else. Add to this the tension about time. Ideally, you want the horizon as short as possible to make it more efficient and more like a market operation. There is also the tension of market migration and how to draw the boundary.

Response: From an incumbent utility perspective, if you are counting on using your customer base to buy or build new generation and they are in flux, it offers little certainty about cost-recovery – for thirty-year generation plant investment.

Comment: You need service sets available to all customers. The cutoff occurs in the type of pricing that the different customers see. The rate may be less variable for residential or small commercial customers. But the model of how it is supplied should be the same for all customers. In Massachusetts, default service and SO are completely different, causing a huge dichotomy in the market. We have seen historically that the risk of migration for residential customers is significantly less, and not always because of pricing.

Question: How does this model get new supply into the market? Why would a UDC or LSE contract for a resource if we do not know we will have the needed?

Response: For the non-core market, there must be a requirement that the ISO enforces as an option.

Comment: In the natural gas market model, the LDC buys with a mixture of contracts that allow for enough certainty in both the pipeline and the wellhead market for capital supplied to that sector.

Comment: I agree that large C&I customers should not be provided with POLR service. The policy direction ought to get to where they will have to find a solution to their supply needs in the market. I think the market is amply developed in places like New England. But the dilemma is with the core customers. You can still design a backstop service and regulatory framework to move them to a market with real choices.

Response: When Massachusetts gets into 2007-2008, if there is still no market, it may have to look at a portfolio management approach with a restriction on customer choice. The model is that customers are free to choose, but then they cannot go back.

Response: Some non-core customers will not necessarily want to remain non-core. Maybe those testing the market are saying it is not so great. Maybe what we think is the non-core customers will become core, because of aggregation.

Comment: California lifted its rate cap in June 1999 and the market was generally stable for a year. Then the legislature came in and within 45 days recapped the rates. There was zero tolerance for rate volatility.

Comment: The volatility in California is not the same volatility seen with twelve-month bilateral contracts, where you go into the real-time market for supply. In Massachusetts the model set up for March 1, 2005 is less volatile than the old regulated model in which prices changed quarterly with the fuel charges.

Comment: Without some variability, you set yourself up for price shock. If you cap prices and then decide that they will end sometime, there will be a problem. Without variability, you may have more cost deferrals. In a decade you may have to collect from ratepayers, and with interest.

Question: In the natural gas market in the last several years, we have been promised that prices will come down when they spike, because investment will follow the prices. That is where we have storage capabilities, but electricity does not offer that option. So regulators or legislators step in and create rules and then your variability is gone. Therefore, what is the mix that allows the markets to work but still has the regulation necessary to provide the stability demanded by both that customers and investors?

Response: We need to manage our way through the next years. But I do not know how long we can expect marketers to be in the game without incentives.

Question: How can we seriously consider a national competitive market versus a regulatory market until we deal with the RTO and related jurisdictional problems?

Response: We need a solid wholesale market that is active and dynamic.

Response: The states and regional that have decided to pursue a retail competitive market are absolutely at the mercy of what happens in the wholesale market. If it is flawed or is not progressing at a suitable pace, the best-designed retail market in the world will certainly fail.

Question: The design and structure of default service is also a question of a certain expectation of reliable service. Is there a defined standard? Who sets it? How is it built into the definition of default provider or POLR? Who is the enforcer?

Response: The cost of being a POLR, even if it is a distribution company, is somewhat mitigated because much of the electricity being supplied to the markets comes from that same distribution company. Thus the cost of being a POLR may not be that significant.

Response: Massachusetts handed that off to federal control. However, the state commission still has control over transmission planning, which cannot be done in isolation from what happens in the generation market.

Response: The capacity issue exists in both the competitive and non-competitive worlds. If there is a problem with it, it does not mater whether or not there is retail competition.

Session Two. Regional State Advisory Committees and Grid Governance

Over the years proposals for regional electricity regulation have generated considerable debate but little else has followed. FERC's SMD proposal outlines a formal role for state regulators in governance of RTOs in the form of Regional State Advisory Committees (SAC). Is this an improvement over previous regional regulation proposals? Should SAC be advisory, or should they have greater authority and impact? How much authority or deference, from both legal and policy perspectives, can FERC give to SAC? Assuming delegation is permissible and advisable, what should be delegated? How much of the preemption concerns expressed by some state regulators can be addressed by the creation of SAC? What is the risk that SAC will become an added regulatory burden rather than an effective regulatory vehicle? Will FERC intervention be required to avoid deadlock among the competing concerns? What is the relationship between a SAC and an RTO board? How should SAC activities be financed?

Speaker One

The Mid-Atlantic Conference of Regional Commissioners has a memorandum of understanding (MOU) with PJM. There are three main entities in the PJM governance structure: the independent board of managers which includes the RTO staff transmission utilities, generators, LSEs, suppliers, marketers, consumer advocates and end users. This is the decision-making body. They participate in several committees, the largest being the members' committee. Its public utility commission represents a state. The PJM board of directors must be independent and have no financial interest with any of the market participants. The board is knowledgeable, coming from throughout the country and its members have a background in transmission, generation and electricity in general.

Their primary responsibility is to ensure that the markets are operated by the RTO in a fair, efficient, reliable and non-discriminatory manner. Most mid-Atlantic's state commissioners think that is the way it should be because it has been working fairly well in the last five years.

Market participants are also active in the RTO process. They have the ability, through a stakeholder process, to help define PJM's rules and assist it in solving market problems. There are stakeholder committees where the market participants are really advisory to the PJM board. Obviously, states have a unique position within PJM. They have no financial interest in the market. Their interest is in serving the customers. By law, they must ensure safe, adequate and proper service and reliable, reasonable rates.

The MOU with PJM was established in 1998 with the original PJM states that signed on. The states decided at the time that they should not be members of the members' committee. They thought that they could have a higher level of communication with the PJM board if they were not members of the committee or the board itself. The MOU defines the organizational structure as set up to enhance communication among the states and the PJM board specifically, for cooperative action between the two bodies, especially in matters where both have similar or overlapping responsibilities such as resource adequacy, transmission siting and planning, energy efficiency, demand response programs, market monitoring and development of a competitive wholesale electric marketplace.

Some of the provisions of the MOU include a committee in which one commissioner from each of the states serves on a liaison committee that meets with the PJM board of managers. It monitors PJM events and the proposals that come from the members' committee that are specifically related to the operations and function of PJM. The board of managers and the liaison committee meet at least once a year, or as needed, as set forth by the MOU. The MOU provides for different codes of conduct, such as confidentiality. The meetings are designed to increase communication and facilitate the necessary work and relationships between the state commissions and the board. Frequently, a group of states will submit a joint proposal. The MOU does not preclude an individual state from sending in its own proposal or taking other actions with PJM.

Staff participates as non-voting members in PJM's working groups and subcommittees. PJM encourages staff and commissioners to participate in helping to develop policies and to resolve issues. Currently there are discussions about the future role of state commissions within PJM because of the growth of PJM West and possibly PJM South, and the proposals coming from Washington that are being discussed by state commissions around the country within NARUC. Questions asked are how the various state utility commissions should involve and interact with each other; whether there should be one advisory committee for all of PJM and whether the original PJM states should stay separate and then have a relationship with the expanded PJM West. Including ConEd and future AEP integration.

Following Enron, state commissions are focusing on wholesale electricity markets and PJM's new market monitoring unit. State commissions believe they need more access to real-time outage information and real-time generator bidding information. Obviously, proprietary and confidentiality agreements must apply, but state commissions are used to dealing with that at a state level.

Question: Does the MOU have a joint process for pre-approvals to speed up construction if transmission expansion comes out of the PJM planning process?

Response: The MOU is not very specific on any of that. PJM's procedure manuals are on its Web site. They contain good modeling that is useful for the states that often lack the staff for that kind of work. To a large degree, states will rely on PJM's information for their capacity and transmission needs.

Comment: In terms of state siting processes it is not binding.

Question: Please give an example of proposals from states to PJM's board.

Response: One proposal is how to help Delmarva Peninsula with its capacity issues.

Speaker Two

My comments reflect my experience over the past six months working with six states to develop the Southwest Power Pool Regional State Committee, or SPP. SPP is contemplating filing its RTO application or seeking recognition as an RTO. These are still in a developmental stage.

States in the SPP footprint that would be members of the SPP RSC are: Texas, Oklahoma, Missouri, Kansas, Arkansas, Louisiana and New Mexico. There are a few SPP members with operations in Mississippi, but they are munis and coops that are not jurisdictional to the Mississippi Commission. Consequently, RSC discussions have only involved the state commissions in seven southern and midwestern states. This is the first RSC being developed post-"white paper" but along the line articulated in it. It is also the first RSC being developed simultaneously and in conjunction with an RTO.

One of several observations I offer is that the viability and practicality of utilizing an RSC in an ISO or RTO context and the issue of whether the RSC should be advisory or decisional rest largely upon each member state's legal and/or regulatory policy position on the loss of state jurisdiction over the transmission component of bundled retail electric service. This is critical in the SPP footprint because none of the states have retail competition with the exception of Texas.

The viability of an RSC depends upon whether each state's statutory or constitutional scheme for its public service commission is authorized by state statute or constitution to participate as a member of a regional decision-making organization or compact. Kansas, for example, does not believe it can join the RSC as currently structured without its state legislature addressing this issue.

If all or most of the states in the RTO region agree that an RTO is either a lawful exercise of FERC jurisdiction or that it is in the state's net public interest, the RSC's implementation is easier. States that believe there is a legal basis or a competitive need for comprehensive FERC jurisdiction over all transmission service prefer the advisory scheme. Others will require the issue to be judged in the context of a public interest analysis. For some, the quantitative cost-benefit analysis will be a tight case. Some will look at RTO formation in a qualitative context in terms of assessing the net public interest. Perhaps a decisional RSC will produce qualitative benefits that should then help the net public interest analysis in states lacking quantitative benefits.

If FERC is flexible and approves different RTO models based on regional differences, I believe the RSC can become viable in that context. Where there is no change to the current jurisdictional scheme, the RSC can either play an advisory or a decisional role on FERC-jurisdictional issues. It can also perform a regional coordinating function with respect to issues that are state jurisdictional but ought to be handled to promote regional consistency, such as generation and transmission planning, resource adequacy, fuel diversity, portfolio management and demand response. To the maximum extent possible, the goal is a regionally coordinated approach to those aspects of electric service. Where there is not jurisdictional shift to FERC, one benefit is that the member states need not worry about the wisdom of an RSC supplanting its state jurisdictional decision on issues that impact retail service. SPP RSC intends to go forward with an RTO that does not contain any jurisdictional shifts. Whether it can realize that depends upon FERC's reception to the proposal.

Another observation is that the RSC can exist as a matter of contract law. Assuming a jurisdictional shift and the RSC being decisional on certain issues, would state commissions cede their authority to it? Many people want to preserve the jurisdictional status quo, but if that does occur, then what happens to the RSC?

Utility membership in RTOs is important for the public interest analysis. It is easier to come up with the net public benefit of moving forward with an RTO, but to the extent there is a jurisdictional shift, a shift in operational control and a more sophisticated RTO structure, then the cost benefit analysis is more difficult.

The bottom line is that the similarity in regulatory philosophies among the states will be the key factor in whether the RSC will be an effective organization. It will be very challenging to move forward if we do not maintain the jurisdictional status quo. I think this is the ultimate test of the effectiveness and viability of the SPP RTO and the SPP RSC. If we preserve today's jurisdictional allocation, I think the RSC can play a great role with respect to participating in the emerging developments of wholesale markets in conjunction with FERC and the RTO.

Question: Would you still want to keep state and local siting at the local level or is there a backstop at the RSC?

Response. The RSC performs two categories of functions: being decisional in those areas that are clearly FERC jurisdictional as outlined in the "white paper," and serving as a coordinating body for state jurisdictional things, such as transmission siting, generating planning, etc. I think that the coordination of state functions will be a value-added function that no RSC can provide.

Question: Could a state that may be in the minority vote of the RSC go to FERC to fight the majority decision?

Response: Everyone has 205 filing rights.

Comment: But in the end, FERC could overturn the minority state's position.

Speaker Three

In much of the discussion about RTOs or RSCs, the idea is a regional government. Under the US Constitution, the only two places for ultimate authority are the federal government or the states. The exception is when there is an interstate compact. But both Congress and the states must voluntarily accede to it. Congress authorizes the states to join and un-join. Therefore, once the ultimate authority is determined, everything else is advisory and/or consensual. Ultimate authority cannot be delegated.

Electricity is a mix of state, interstate and federal. I use those terms advisedly; that is, not just state and federal, but also interstate. My conclusion is that a state-federal mix is inevitable. Electricity is simply too complex and too political ever to be federal only. This means that ultimately, multi-state entities will either advise states or the feds in some manner.

There are practical questions before you form a multi-state entity, or MSE. Why is it being proposed? What is it supposed to do? What problems does it address? If Congress is involved, is the ultimate authority state, federal, split or joint?

Will an MSE result in better decision-making or just more red tape? Will it be an improvement? Simply providing a forum for discussion could be a meaningful exercise, but it is not very forceful. Perhaps its recommendations would have presumptive influence at the ultimate level, if FERC were the ultimate decision-maker. Contractual arrangements are also an alternative. Sate governments can contract with each other for certain functions that they perform. While they cannot ultimately delegate their authority, they can agree to cooperate within their authorities. Utilities can contract with each other to perform certain functions, although each is still governed by the state or perhaps FERC. The contracts can be legally binding only if they are within the legal authority of the entities doing them.

What is the composition of an MSE? Does it have a federal member? Does the governor or legislature appoint the members? Do you have votes or operate by consensus? Typically, MSEs are composed of people who have other jobs and often they are hard-pressed for funds. Who pays the costs of travel to meetings in the various states?

The western US has a long history of cooperation in electricity matters, partly because its grid was developed for long distances and in many states. The Northwest Regional Power Council was created for BPA oversight. Congress created it by interstate compact and each state legislature voted to join it. It is largely advisory, helping the states and utilities to forecast generation. The Western Interstate Energy Board, originally designed to address nuclear issues, was also created by interstate compact. The Western Electricity Coordinating Council is the latest name of a series of organizations. It adopts and implements grid standards. WECC is not an MSE in the sense of state governments. It is utilities contracting with each other to carry out their obligations under state or federal laws. You are liable for contractual penalties if you do not abide by its contractually enforceable grid reliability standards. The Northwest Power Pool was formed by contracts with and among utilities to monitor and coordinate the region's load balance.

My point is that the western US already has Mess to carry out various purposes. Whether it needs another one, should there be an RTO, is an open question. Would the RTO be a natural extension of the Northwest Power Pool or WECC? Rather than trying to prescribe at a FERC or Congressional level, it is better to wait for the need for another MSE and allow it to form around the need, recognizing that it is really relatively minor compared to the larger question of who has the ultimate authority.

Speaker Four

October 15, 2001 was the kickoff of FERC's RTO week. At the time, I commented on the collective attitude of Illinois, Indiana, Ohio, Kentucky, Michigan, Minnesota, Missouri, Ohio and Wisconsin. The region was already frustrated at FERC's lack of attention to its concerns. My comment stated, "On June 4, 1998 in Indianapolis, we began to formally warn FERC about the consequences of its inaction with respect to the formation of ISOs. In presentations in St. Louis in February 1999, several Midwest colleagues urged FERC to use its authority to provide the leadership for multi-state RTO formation."

I cautioned that if we proceeded on a voluntary basis, it was very likely that RTO formation would proceed at an impossibly slow pace. Frustration was expressed again in 2000 and in 2001.

In 2001 we said, "Midwest regulators have been working with transmission-owning utilities, merchant plant developers, marketers and other stakeholders as they grapple with the myriad issues surrounding MISO and the Alliance RTO. But the progress has been excruciatingly slow and difficult. We have seen transmission owners jump from MISO to ARTO and back again as conditions change and their attitudes shift."

In October 2001, we said, "The Midwest States are eager to proceed with a Section 209 board process that is acceptable to FERC. We would also be amenable to any other partnership arrangement that might better suit your interpretation of your statutory authority. FERC staff mediation and/or arbitration are welcome, along with assistance from attorneys, economists, market and technical experts, and others who might contribute to the effort. Effort of an interim FERC Midwest task force to address near-term issues would also be a possibility."

On July 31, 2002, when FERC released its SMD NOPR, Michigan and the Midwest generally reacted favorably and were encouraged by the fact that an energized FERC was trying to get some needed things done that we were expressing. The Midwestern states were encouraged by the SMD that pointed out that there was not a formal process for state representatives to engage in a similar dialogue with the independent entity that will operate the grid under SMD. We were encouraged when FERC proposed to establish a formal role for state representatives to participate in the decision-making process for those organizations, and by FERC's vision of an independent transmission provider operating the grid and having a regional state advisory committee with direct contact between that entity and the governing board. We were encouraged that FERC recognized that market monitors would report to the state committees on the same basis that they reported to FERC and to the RTOs.

On February 28, 2003 twelve states filed joint comments on SMD at FERC. The state commissions sketched out an initial framework following some of the provisions within the SMD NOPR for a regional state organization that was tentatively labeled the Midwest Multi-State Committee. When FERC issued its "white paper" on April 28, we discovered that others saw things similarly. We joined forces with the mid-Atlantic and the northeastern regions. In June 2003, the Organization of Midwest States was chartered to promote the public interest and social welfare by providing a means for MISO states to act in concert and to coordinate transmission issues relating to pricing, market monitoring, generation and transmission needs and to coordinate with FERC and MISO on issues of mutual concern. Among other tasks, the MISO states have been working on the tedious aspects of forming a corporation, putting revenue requirements in place, hiring a director and setting performance metrics.

These states have been through several gubernatorial changes. When attempting to achieve regulatory certainty, it is very difficult when you have the changing political mix and are trying to have people focus. For example, a new governor took office in 2003 in Michigan. The highest administrative priorities are the two-billion-dollar budget deficit and getting the new administration up and running. Then add to that regional backdrop the national politics of energy legislation, and what the states view as threats to the region and its interests in the pending energy bills. This is the ongoing process that Midwesterners will wrestle with in the years ahead.

Speaker Five

It is difficult for me to promote delay in the voluntary nature of some of the things under discussion. But the results and the ramifications of doing something even if it is wrong could have considerable consequences. When the south talks about regional coordination and advisory councils with or without an RTO, it can be a good thing. The increased communication among state commissions is positive for the region. There is no doubt that our wholesale markets are regional and that state commissions and other state entities will decide how the system is explored and expanded. If there are regional benefits we will have the opportunity to take advantage of that low-hanging fruit. The southern region in general has large utilities that serve multiple states. Coordination and regional planning are easier when there are fewer utilities.

Aspects of FERC's RSC proposal are bothersome. First is that states are advisory and that FERC will defer to them. The state laws under which most of us operate would not allow us to give away any of our authority to an RSC. If the purpose is to make recommendations to FERC about how to make its decisions, the commission's track record in listening to the states has not been very good. The punitive nature of such a jurisdictional body is already evident. Georgia has not quite fallen in line with the message from Washington and so its IRP and bid process have been attacked, certainly by a non-winning, probably non-complaining bidder at the time when new load was awarded. The complaint pending before FERC has credence because of Georgia's unwillingness to participate in this process. Kentucky has also been dragged in front of the altar of FERC sacrifice. Is it punitive? I do not know, but it sends a strong message to the other states that have not really been willing participants in this process.

RSC should not have its own authority, nor should it have any authority over individual states. Nor should FERC delegate authority to it. If states within a region agree, whether through a formal RSC or informal working groups or even comment filed in a particular docket, FERC should give substantial deference to that position.

While I am not overly positive about the formation of RSCs, I believe the concept is better than formal regional regulation proposals that would preempt states' rights. We do not need to create new bureaucracies. Having an RSC preempt the states by a majority or even two-thirds vote is not much different than having FERC preempt the states. In conclusion, keep it simple, as informal as possible and have RSCs aid the process, and not present another roadblock.

Discussion

Question: When setting up an MSE, if you leave out seats at the table for some of the other major players, how could the MSE be effective?

Response: The control areas are smaller and there is not much of a DC influence in Michigan or in the midwestern region. The region could learn from others about control areas.

Response: In the northwestern US, there is no RTO without BPA. Politically, there is no RTO without the participation of the public utilities. The majority of transmission and the majority of utilities are not FERC jurisdictional. If anything is formed, it will look very different.

Question: How should FERC proceed if it finds undue discrimination in the regulation and use of the transmission grid from state to state and in interstate commerce?

Response: You must analyze each case on its own merits, based on the evidence of record and then develop an appropriate remedy to resolve the particular type of discrimination.

Response: You cannot speculate about the remedy before you know the facts of the discrimination.

Response: The first element is that FERC actually finds some real, contested facts in a real evidentiary hearing. Depending on the nature of the undue discrimination that would lead to some type of remedy. If there have been specific allegations of undue discrimination, there can be specific remedies. In general, pick the remedy that is most tailored to the discrimination at hand and that does the least harm to those who have not discriminated. The real issue is what constitutes undue discrimination. Is it undue discrimination for a vertically integrated utility to prefer its own customers in the use of the transmission system for bundled retail service under state law obligation?

Question: What about a vertically integrated utility discriminating in preference of its own generators when there are cheaper generation alternatives?

Response: You would look at the arrangement under state law and the justification. For example, if a plant is in rate base, is the utility's obligation to do least cost? It may be better to use your own generator. In a regulated system, the state regulator ought to be able to ensure that it is in the interest of the state's ratepayers. In a deregulated system, you do not really have anyone looking after that fact.

Question: Is there a federal remedy if the vertically integrated utility is blocking the ability to ensure that independent generators get just and reasonable rates?

Response: If a utility has violated OAT, you go after them.

Comment: I encourage FERC to do some of this so that we can develop cases with specifics to use instead of anecdotal, speculative information. A few years ago, Michigan took an economic development approach to encouraging new merchant generation in the state. It found that merchants' requests for engineering work got short shrift and that the costs were a little bit greater for merchants than for incumbents.

Comment: We could have a good system if we design it sensibly and put it in place. But we lose the ability to discriminate against third parties and exclude them from using the transmission grid so that in effect we can capture the economic benefit of their availability without having to pay them for it or to contract for it because they are trapped in your area and you can take advantage of them. If you want to have discrimination and to preserve that capability, what you cannot do is get rid of it and not fix the model in a way that is essentially at the core of SMD.

Comment: I think that not having a mandatory set of rules or requirement to develop an RTO that meets with FERC's vision is what we are trying to avoid in the energy legislation pending in Congress. I advocate a middle ground. Independence is a god idea for many reasons. I think you can set up independent monitoring of transmission and the market, independent transmission planning, cost assignment and administration of tariffs without expensive bells and whistles and without transferring jurisdiction to FERC over the transmission component of bundled retail sales. If we get that model blessed by FERC, I think may people will move forward in regions that have not yet done so.

Response: SPP already complies with most of what is in Order 2000. It is an independent entity and has been since the 1940s. It has had a regional tariff, and an OATT and has administered other regional tariffs since 1997. It also grants transmission service requests. It does not show preference for the wholesale market over native load customers. It does not do anything that impairs the rights of native load customers, which is the critical issue that most state regulators in the region have.

Comment: There are a few core things you cannot do differently if you want to give people open access and be non-discriminatory. The problem I describe is not a jurisdictional question. It is the physics.

Question: Is your scenario one in which the states do or do not have jurisdiction over the transmission component of bundled retail service?

Response: I do not care who has jurisdiction over the bundled component.

Comment: I think the problem is that there is no middle ground on jurisdiction. The problem with the states losing the jurisdiction, in order to solve the problem of FERC being able to do something about undue discrimination is that in the course of that transfer of jurisdiction to the feds, states lose a lot more, such as the ability to have vertically integrated utilities, and the ability to require or enforce integrated resource plans because the system is no longer integrated. They lose the ability to ensure adequate generation supply because generation and transmission are substitutes for each other. For example, a utility that needs some more generation must decide whether to build on the west side of the mountains where it does not need transmission, or on the east where it would have to build transmission. You would have us dismantle what we think is good for our region or to put it another way, it is our jurisdiction that we think enables us to deliver the system we want to deliver. From my point of view, this is more important than whether an IPP has the kind of access you want it to have. I do not know why some states have been so willing to give up political and jurisdictional control because they cannot go back once that is gone.

Comment: Ten states have gone back because they still have the legal ability to do so.

Comment: If you want to have non-discriminatory access, it is essential that operational control over the short run must be handed over to something like the ISO. You can have the old world, or you can have the non-discriminatory world, but I do not think there is a middle ground.

Response: My state is not so interested in what is built on the east or the west side of the state, but on what is being built in other states that can affect us. How do we efficiently view all of that, as opposed to thinking only within our state's confines? My state unbundled and gave transmission oversight to FERC and this has worked just fine.

Comment: Some regions have institutions that lend themselves to an expanded decisional or advisory authority.

Comment: If an MSE wants to expand, I do not see any barriers to having both advisory and rule-making bodies.

Response: The more states that are involved with an MSE like PJM, the more difficult it will be to have more significant input.

Response: A practical aspect is the interrelatedness of the organization of states with RTO development. Do states in MISO develop an organization that will be advisory or decisional to MIOS, only to see major utilities then move to a different RTO as boundaries change?

Question: Are you unalterably opposed to any federal backstop authority on transmission siting?

Response: The conventional wisdom that nothing is sited anywhere is not the case. I think you have to document it as a national problem before you go ahead with anything very strong. But when you create a backstop authority, you now have a two-stage process that I think allows the state authority, if the project goes through that phase first, to pass the buck. It also extends the time. And at the federal level, the same issues will exist.

Comment: With few exceptions, most state statutes say you have to look at intrastate need. The Cross-Sound Cable project was denied approval by Connecticut's siting authority because of alleged damage to the aquatic life in New Haven's harbor. The company renegotiated and changed its routing. The siting authority approved it and then the state imposed a moratorium. The issue has now been resolved by an order of the US Department of Energy. How should one resolve this?

Response: If what Connecticut did was wrong, is the remedy a national federal backstop authority? We have a federal-state system of democracy. Unless you say that we will dissolve the state authority and put everything at the federal level – which is totally impractical and would involve changing the US Constitution, there will be times when the ultimate authority – a governor, a state, a legislature – does something that another state does not like. In the end, if it is a matter of interstate commerce, I think that Congress can probably change that law. But you will not get a remedy to your liking every single time.

Response: This is an instance where the federal government must be the backstop because Long Island needs electricity and New York has not built enough generating stations. When you have something as substantial as electricity with interstate commerce, politics should not get in the way and the federal government must step in.

Response: If you have a rational discussion about needs, most governors will acknowledge that there are some concerns that transcend particular state interests. But a governor cannot tell his constituents that he favors handing something over to the federal government. As a practical matter, I think the answer is to look nationally, finding a way to finesse the politics without giving the opposition new ammunition about how awful the federal government is.

Question: Will state advisory committees become an added regulatory burden rather than effective regulatory vehicles? Will FERC intervention be required to avoid deadlock among competing concerns?

Response: If you look at who the ultimate decision-maker is on some of the issues, depending upon whether or not there is a jurisdictional shift, FERC will be the ultimate decision-maker and the regional state committee will only be advisory.

Response: I think that the state-level decision-maker does not have quite the same pressure to make a decision. If it is a really tough one, you can let the feds decide.

Response: Right now there is a legal debate about whether the ultimate authority is with FERC or the states .At a non-ultimate level, the meaning of a controversial decision or action can help flesh out a record or get some issues off the table.

Question: There are two questions in siting: need determination and the actual routing and siting of a line. If there is a regional need, is there any local interest in saying, "No, there is not?"

Response: How will the need be defined? Is it reliability or is it to make sure there is enough transmission service to satisfy every single request made by every interconnected generator in the country? Then you ask how the costs will be allocated? Once you answer those, siting should be relatively easy.

Question: Assuming that a line will not be in state rate base, do you then care about how the costs are allocated since the users will pay for it? A state may have an environmental and aesthetic interest, but what possible economic interest does it have?

Comment: If there is more interconnectivity, then up to the limits of the transmission lines there will be more transactions from the lower-price market to the higher on the wholesale level. But sooner or later, the retail customers pay the bill. Whether you have retail choice, eventually through fuel adjustments costs or rate cases, it does flow through and that is the parochial interest in terms of the energy costs.

Comment: FERC needs to be flexible and we need to come up with some middle-ground solutions that do not involve a shift in jurisdiction.

Comment: The political strife does not go away, if there is no energy bill.

Comment: If we cooperatively examine our differences, find a common ground and plan ahead for siting, we can give the industry confidence, reduce the regulatory burden and become proactive in reaching decisions collectively before the either/or option is implemented.

Question: Who will control day-to-day operation of the grid?

Response: In SPP's current RTO filing, it has operational control as to reliability issues. SPP is a reliability council and will continue to do that. There will be an independent system administrator of transmission tariffs to calculate ATC and TCC.

Question: Is mandatory compliance part of the equation for reliability standards?

Response: I think everyone supports mandatory reliability standards, but that is different from creating a new control room.

Comment: I would argue that in the August 14 blackout we had an air traffic controller – MISO – with no authority and the result was chaos in the air.

Response: In the west, utilities have contracted with Bonneville Power Administration to be the security coordinator that sees the whole picture. When something goes wrong, there are communications up and down the line. There are responsibilities. It is when you introduce different incentives that you need mandatory standards because otherwise there is an incentive to cut costs.

Response: Part of the problem is that no one knows the future of the electricity system, or if you will own your own transmission system or be able to control it.

Comment: The regulated system in the west gave us the blackout that created NERC and other results that were not necessarily good. The problems did not just crop up in the last six years since we began to introduce markets.

Comment: If analyzed fairly, August 14 might well push us where we want to go, because the process and the facts will be transparent and available to everyone and people can model it on their own. We will know if we can lessen or prevent something with reliability standards that Congress must pass, with or without the pending energy bill.

Comment: The problem is too many small control areas with too many coordination issues that arise at the seams.

Comment: Electricity is an essential public service. The traditional system has political accountability in which the utility provides the service and the state is there through the regulators to ensure that the rates cover the utility's cost of provision. There may be some form of replacement, but you will not get away from the political demand that people make sure that they have the assets at their disposal to get them the electricity. That is what native load is about.

Session Three. The Virtues of Virtual RTOs

Earlier research on coordination of spot markets examined the theory for integrating markets and overcoming seams problems when there are many RTOs. The concept is a "virtual RTO" that creates a single spot market. Merging the market may be both more important and easier than merging the RTOs. The practical realities of differing scales and configurations, mergers, and stages of development have moved forward several agendas for integrating markets and advancing the objectives of a single market without a completed structure for RTOs in place everywhere. How do we handle seams between spot market regions and more traditional regions? What has been the practical experience? How do different models accommodate the different stages of RTO development? Is there a good solution to the seams problem without a coordinated short-term market? What strategy would maximize the success of electricity restructuring? What risks do we run with poor or incomplete market designs?

Speaker One

When a national survey asked customers what was important to them, price was number four and reliability and power quality was number one. Prior to the Energy Policy Act of 1992, we were building about 13,000 miles of transmission every year. When FERC issued Order 888 in April 1996, investment in transmission went through the floor, while investment in generation went through the roof. I submit this was almost predictable with the uncertainty that the transmission providers faced across the nation. Following Order 888, Tennessee Valley Authority, for example, did 24,000 transactions in 1997. In three years, it was 251,000 transactions.

The largest single loss in this industry has been the siting of generation. When England first deregulated its market, it doubled its transmission budgets before opening the north fields. If we had spent as much time in transmission investment management as we have transmission congestion management, we would not have to manage the congestion nearly as much. We need mandatory rules.

Virtual RTOs are about data transfer on a real-time basis. The data comes form amps and volts in addition to market data between control areas and between RTOs and reliability coordinators on a real-time basis. An RTO is a tightly coordinated group of transmission providers that agree to provide non-discriminatory service to facilitate a seamless market. It must be reliable and reduce consumer costs. In essence, the virtual RTO will coordinate congestion management between the various markets with multiple RTOs and ISOs and other providers. Having the same data tells you with some degree of granularity where the flows are going across the network.

TVA already shares real-time data among several systems to allow this to work. An LMP system can coexist with a security-constrained economic dispatch system. In my opinion, whether you use incremental cost curves or bid process does not matter. Governors of the southern states have made it clear that we have to transfer some of the benefits back to low-cost states; if we do not, they will continue to be very slow in moving to a wide area market. Regional differences are primarily price and the politics that go with the difference in price.

The advantage of a virtual RTO is that it lays the foundations for common system models and protocols. It minimizes the unintentional consequences regarding future market paths. The system can move in either direction as the uncertainty of deregulation and legislation faces us. It supports the expansion of the transmission system. With the existing control centers and the fiber optic capacity we already own, it provides the ability to transfer data in large quantities between control centers. It also coordinates all actions, one of the problems on August 14. TVA has signed memoranda of understanding with SeTrans and Southern to transfer real-time data and coordinate reliability so we are on the way to linking the control systems.

Setting up a virtual RTO is much lower in cost than what was spent on the Power Exchange and CAISO. It is about data, not about buildings and adding a lot of people. It's technologically achievable. Finally, it gives us flexibility, when looking at the uncertain future.

Speaker Two

Although there are real RTOs in New York and PJM, we are not yet finished. We still have loop flow impacts from transactions between RTOs. We need to schedule transactions more efficiently, taking into account congestion impacts and optimizing flow levels, and also avoiding reliability surprises. The old contract path system is inefficient in solving constraint. It is also a slow system because when you start cutting things, eventually something happens, but you do not know how long it will take to get a response. Coordinated dispatch results in more efficient management of constraint.

Another problem is how to set the level of interchange flows. What generation will meet the net load is a matter of how you map it. A third concern is how to optimize the level between the control areas. There are several issues, such as the export charges that reduce the level of exports and interchange. But more complicated is when market participants put in schedules and need to see what is happening in terms of prices, the ISOs must do the security evaluation. The scheduling entities do not know the slope of the supply curve, or how much LMP will move up or down. If we can coordinate, we can run the system harder and closer to its limits and that is money in consumers' pockets. Another constraint is that if we go to LMP, there are still different areas for load shedding and ICAP systems. For example, there is no agreement between New England and New York that when New York is short of capacity, New England will shed load to keep the lights on in New York.

In principle, a large, combined RTO could solve all of these problems, but there are costs, implementation risks in changing; and coordination limits. In our economy we do not always have one big company running everything; decentralization is often more efficient. A virtual RTO that exchanges constraint information and shadow prices is a step that can solve our congestion management. It can also get closer to the movement of flows.

Today, for forward-looking evaluations, ISOs rely on market participant schedules for two, three and four hours out. We need a mechanism to replace that, given that we have to get the settlements process correct so everyone ends up with the right amount of money. This does not solve the congestion management problem, but when we put it in place, all of the market participant transactions between New York and New England, for example, will become purely financial and will have no impact on the physical schedules.

In terms of benefits, there is always the concern about cost shifts between regions. Fundamentally, hourly transactions will pull the price up. When moving the energy on a five-minute dispatch, sometimes too much or too little power will go into New York from New England. We want the gains of moving it more efficiently without necessarily changing the level of prices at all. The things that affect congestion management may affect the aggregate level of prices because you might be able to run the system harder. If you were always constrained, the constraints might be looser. This is the limited vision of virtual RTOs that is being pursued in the northeastern US.

Speaker Three

SMD is like the old VW bus that people loaded with baggage and thought would go at the speed of light. Unfortunately, it has become a crawl. Realistically, only New York, New England and PJM have RTO's. SPP is the stealth RTO that some believe will have an LMP market in place sooner than MISO.

The new ERO is intriguing; moving away from a voluntary basis to more of a regulatory penalty. How do you impose penalties if you do not have real-time control over the market? Can you run a physical market without also operating an energy market? An energy market alone without control on the operational side will not provide price transparency or liquidity.

I think that MISO has all the worst elements of whatever an RTO was trying to do. MISO has no real-time control over its system. Commonwealth Edison's and AEP's uplift charges are a concern. MISO members are now looking at the Atlantic City case to see if they can withdraw from MISO and that creates additional costs and concerns.

Curiously, MISO and PJM if it insists on having both utilities in it are one market. There are 300 flowgates that have an impact on each other. Loop flows, particularly in the Michigan area creates a huge potential for shortfalls. A question is why PJM did not simply operate the market, leaving MISO to plan expansion and collection.

So we are back to the RTO heavy–RTO lite concept with New York, New England and PJM the heavies, and RTO lite those for whom FERC can set a minimum baseline.

California appears to be a question of governance, moving backwards in terms of a cast-of-service approach, and still clinging to a balanced schedule approach. How will it get new investment except through a cost-of service approach, unless there are market rules? In the northwest, we have said that as a government entity with transmission, Bonneville Power Administration should be the RTO and run the market. In the south, Southern and Entergy operate their RTOs well, but we would like to see others allowed in. We would also like to see TVA join MISO or perhaps join PJM, to the extent it can go beyond its legislation, or can develop a regional energy market with the south.

What minimum elements can be extracted from these areas? If you will be dispatching the system in real time, one priority is to do it on a transparent price basis. No matter how we work the equation, we keep bumping into that.

Speaker Four

If you can coordinate the transmission congestion and energy pricing at the border points between PJM and MISO, the interchange between the two areas will take care of itself because the market transactors will manage it. How do you make the most efficient management of congestion? The challenge with seams is that while the grid does not stop, the market does, just because it crosses a boundary such as a state's border.

PJM probably has five or six constraints that occur regularly near borders over which it has limited control. There is one constraint where PJM monitors the transformer but lacks a generator it can move to resolve the constraint. PJM can see the constraint and declare a TLR, but that kind of situation causes some limitation.

PJM has had loop flow impacts. It has had to make some pricing rule changes at its borders, but prices are not coordinators. There have been some situations where power has poured into PJM from non-abutting areas, but again, PJM cannot see that far out. It needs better granularity and efficiency than TLR.

PJM is using a system to run the markets, including the PJM area and border points. Its models extend into New York, to the south and to the west. The test system has 5,900 substations, 2,000 generators and 14,000 lines. This increased size prepares PJM to monitor outside constraints in adjacent markets in real time. Exchanging data can show others how much it costs PJM to resolve these constraints. However, there are no business rules in place that define the flow entitlement of an adjacent market on a constraint on PJM's border. Obviously, both RTOs have some entitlement, and obviously if the reciprocity would be one-sided, there could be rule changes. But who receives the flow entitlement on which constraint?

The approach is to share information in real time and have five-minute dispatch cycles. If PJM sees a constraint on its system, it can tell MISO so it will be included in for the next five minutes. This is not as optimal as converging right away, but incrementally speaking, we use existing software and only have to add communication and data. In other words, as soon as a constraint appears, the real-time markets would iterate to a joint solution.

Reliability scheduling would also recognize the flow entitlements, FTR allocations and options. PJM would give MISO customers a transmission right, or the ability to receive a transmission right, for a part of the flow on a congested line. The monitoring RTO would be responsible for keeping the constraint within criteria. RTOs will share shadow price information.

Settlements can be seasonable or annual, as long as they match up with the transmission rights allocation procedures. Essentially, you compare the power flow for the non-monitoring RTO. If the flow is greater than the entitlement, the non-monitoring RTO pays, based on the shadow prices times the megawatt amount over the entitlement. If it is under the entitlement, the non-monitoring RTO is providing dispatch relief at a lower cost. It is compensated based on the relief it provided, multiplied by the shadow price. Such payments would go back and forth between the RTOs. The congestion management is used to collect the rents and distribute them through either the day-ahead energy schedule process or the FTRs.

Whether you cal them FTRs, CRRs or anything else, the point is to do them jointly, respecting each other's entitlements. This is the single biggest challenge we face in implementation. The technical challenges only cost about $100,00 to figure out.

In summary, PJM has suffered from pricing inconsistencies at the border. It has made some rule changes to fix this. But a new protocol that uses today's technology would be more efficient. It does not cost the native load money because you are helping the other RTO if the FTR allocations are consistent with current PJM business.

Question: Is there always one monitoring RTO for a jointly coordinated flowgate, or does it change over time?

Response: Each RTO is a tariff facility that collects monies and is responsible under the protocols to monitor the constraint. As the markets begin to converge, the monitoring RTO stays the same.

Discussion

Question: How do you resolve regional differences?

Response: Many argue that the regional differences are topographical, like Lake Michigan or Florida. But the largest regional differences are the costs and benefits of a market opening when low-cost states are likely to have prices rise if you levelize marginal costs for the nation.

Response: Right now, we do not have enough investment in transmission infrastructure.

Question: Can the issues revealed in the transcripts of the August 2003 blackout be resolved with an agreement to exchange data and information?

Response: Yes, because it will give you a much bigger look at the parts of the system that will affect you operationally.

Comment: It does not take a tremendous amount of fiber optic capacity to share real-time data among control systems. However, there is more work to do about how to re-dispatch and how to share benefits.

Question: Is it desirable for an RTO that is operating the network in real time to be the judge and jury on penalties?

Response: ISOs are the logical monitor to look at whether the entities within their footprints are following instructions, particularly in a critical situation. And FERC will look over the shoulders of the RTOs. There will also be independent market monitors.

Comment: In the west, BPA is the major energy seller and energy market participant. It is the dominant provider of ancillary services because of its flexible hydro system. And it is non-jurisdictional. PacifiCorp and BOA have about the same amount of transmission miles. Even though it is technically feasible, it is probably not feasible politically for PacifiCorp to take control of the Bonneville system. Today, the two are working to put something together that makes sense for the region.

Comment: Because BPA controls transmission, let it provide the solution in terms of regional coordination. You do not want a power producer also running the market; independence is the primary ingredient to make the market work.

Question: If you add British Columbia, BPA does not even have half the high voltage transmission in that larger RTO footprint. While BPA is a big market participant, over 90 percent of its generation was built for irrigation, flood control and recreation. It also has uniquely federal fish and wildlife responsibilities. If there is an independent operator, there would be some flexibility to use the hydro to keep the lights on, but there would be discomfort about operating the facilities based on the tradeoffs among irrigation, flood control and power. Unless we figure out how to separate reliability operations from market optimization, it would be difficult to have an RTO in the northwest. Would you simply operate the market on a bid basis and the independent operator would have no other ability to make must-run decisions?

Response: New York is heavily hydro and also has constraints other than power, like tourism, that affect how its water is used. The New York bidding structure allows hourly bid changes so that as the water position changes, it shows different information. This can be provided through a market mechanism. This means that you do not have to use the water when there are better alternatives to solve problems, like moving around the thermal generators.

Comment: TVA cannot transfer power to PJM under the current law, but it could bid to reduce its generation and reduce congestion, if someone would pay it for the cost of the generation and its dispatch.

Response: The beauty of the virtual RTO as a federal entity is that it can still meet it statutory obligations and bid into a marketplace. For example, TVA could not transfer power to PUM under the current law, but it could bid to reduce its generation so that it would reduce congestion, if someone else would pay it for the cost of the generation and its dispatch. This approach allowed TVA to integrate into the system; maintain its statutory obligation, and reliability is part of the original statute; and still participate and play into a market run by someone else. TVA itself is not interested in running a market.

Question: Does the virtual RTO software or information system depend on the presence of RTOs in any way, such as assumptions of legal rules between control areas?

Response: No. It does not mater if it is an RTO, a federal entity or a utility company. Exchanging data is very easy, as is calculating the transfer price. The information would be used and useful in meeting reliability objectives, which is paramount. Even if you lack the authority to re-dispatch, the information alone gives you're the ability to analyze the state of reliability of your system.

Question: Can you also see how big a problem there is that could be solved by further structural changes?

Response: Yes, but it is important that constraint shadow prices are not being derived to benefit any one generation or transmission system, or to impose a large wealth transfer on adjacent systems.

Question: As you do real-time dispatch, is there any assumption of local market power mitigation that is needed, and must it be the same across the different control areas?

Response: If you want to solve the constraint in another area, there must be some legitimacy as to where those constraint shadow prices came from Each control area will probably have a market monitoring system to deal with its internal constraints.

Response: From practical experience, the mitigation impact or need will show up quickly, particularly under an LMP system.

Comment: In my opinion, the transfer of data is reliability first, so a market can work, and a market second. Without knowing schedules and having information about what is happening around you, you sit in a control room with your head in the sand. We have not build any significant transmission in this nation in a decade. Originally, we built transmission to share emergency reserves. Now, we are loading it with commerce each and every day, near its full capacity of voltage collapse. We could use the transfer of data to show that people can benefit from new transmission and both the north and the south can make money.

Response: Do not underestimate the value of a spot energy market that is basically tied to reliability because then more people will work to solve the issue that we are trying to fix.

Question: Is it obvious how a settlement with the low-cost states could occur? Is the basis for the sharing simply a political formula, or is there a more quantitative basis?

Response: Long before the market was conceived, power was transferred between control areas on a split-savings basis. It was very attractive economically for both the seller and the region that was producing the power and the receiving region to share in those benefits. There will be a reduction in congestion costs if we go forward. The key is to find a way that we can agree to go forward that benefits our share.

Comment: Many possible solutions to this means that there is an element of equity, fairness and politics. That is both good and bad because it allows room for maneuvering to reach a negotiated settlement. It is critical to make sure that the solution is compatible with the broader design. An example of something that would not be compatible is a rule that every hour for the next five years, we will use split savings to allocate the congestion rates because that would then create a new set of price incentives that would change behaviors in ways that are inconsistent with our design.

Question: The virtual RTO perplexes me. Where is the information going? Who is the operator? Are all of the operators also generators? Will this really improve competition on the wholesale level?

Response: In the south, today's agreements are primarily between the reliability coordinators for the region.

Question: How do PJM and MISO compare?

Response: The PJM-MISO coordination process is to solve the transmission congestion issues that are affected by both dispatches and to manage transmission congestion near the borders more efficiently. Then there will be pricing consistency at the borders. To the extent that the two dispatches become one, the next step is to manage the interchange itself through this joint dispatch. A lot of time is being spent on thinking about how to get the right amount .of interchange to do the job. Now that NEPOOL has LMP, people can look at that before they implement it in their own system.

Comment: The ultimate objective is to get the real-time dispatch done coincidentally in PJM and MISO. That is also where New York wants to go. This is a settlement problem, not a technical one. This is where the rubber meets the road and where we have to work it through. The decision the ISOs make is just how much to change the interchange schedule. Then the dispatch in both regions is what does that, with the bids that are already in.

Question: Will anything in the virtual ISO system help, hurt or be neutral in trying to get new transmission investment?

Response: Today, we have too much generation and it is a pricing issue. The average postage-stamp rate approach does not work very well. Ultimately, we need a system with multiple transactions that will allow new, long-haul lines to be built, and if you get the cash flow right, it will encourage people to invest in those lines. But until we realize that long-haul transactions congest the market much more and thus should pay more, we will never build the long-haul lines that we need.

Response: Transmission lines sometimes are not fully utilized when there is a spread. We should make sure that the long-haul lines generate as much rent as they really should. If we generate the congestion rents, more money goes back to the transmission owners.

Response: The issue between New England and New York is more about governance and how the market rules are set up and the desire to change them, and less about a technological fix in terms of optimizing the market. But getting the governance changed in terms of the market rules is probably the tougher route.

Response: I think the virtual RTO will make it more obvious where transmission is needed. Part of the challenge is who is the beneficiary and who pays. I do not see the virtual RTO itself resolving that.

Question: Will we have a situation in which EROs are viewed as an acceptable substitute?

Response: Identify and prioritize the elements from either a political or a regional standpoint that can be put in place. I think if you want to enforce reliability, you will basically do penalties.