IssuesLetter

FERC 2000 and RTOs:

The Vital Role Of State Regulators

May 2000

Even in the absence of federal restructuring legislation, the restructuring of the nation's regional transmission grids, power markets and reliability institutions is well underway. To support restructuring, FERC is calling for the creation of new institutions-- Regional Transmission Organizations (RTOs) -- which may have dramatic impacts not only on the way that electricity markets operate but also on the role that efficiency, distributed generation and other clean resources will play in meeting the nation's energy needs in the decades ahead. This Issuesletter examines the critical role state regulators play both in forming and establishing the operating rules of RTOs -- issues that will affect the reliability, price and environmental impacts and of power supply in every region.

Because the electric industry is changing so rapidly and because RTOs are complex and just emerging, it is easy for policy makers to get lost in a blizzard of bewildering details. This is unfortunate because in this case, as with other aspects of electric restructuring, many of the details do matter. Fortunately, at this early stage, regulators can usefully focus attention on a few overarching issues that will advance the linked goals of robust competition, reliable service and environmental protection.

Three key areas of concern are:

1. RTO Independence
2. Including Demand Side in Efficient Electric Markets
3. Transmission Access and Pricing Rules for Renewables

Decisions made in each of these areas will greatly affect the viability of emerging electricity markets, the cost of electric service and the reliability and environmental cost of system operations.

1. RTO Independence

The RTO is expected to exercise sole control over access, pricing, congestion management, reliability and expansion of its transmission system. For this to occur, FERC has declared four essential characteristics: Independence; Sufficient Scope and Configuration; Operational Authority; and Exclusive Authority for Short-Term Reliability. Of these, state regulators need to focus most on independence.

FERC has broadly defined what the RTO can be. It can be an ISO, Transco or something yet to be devised. It could be a non-profit or a private-for-profit entity. However, there

are important questions beyond what its structure is for state regulators to ask. Will a RTO will be a regional regulator, a powerful regional mega-utility or a voluntary association of utilities? Will it be something akin to a port authority, with autonomous decision making, fund raising and system expansion capability?

Regardless of its structure, the scope of RTO responsibility and the deference it will receive from FERC means RTOs will possess enormous power. RTOs will be vested, by necessity, with broad authority to set and oversee pricing, operation and expansion of the transmission system. As the gatekeeper within the electricity system, RTO policies will be a major force shaping electricity markets and will, in many ways, determine which resources thrive and which do not survive.

Experience shows that once a particular RTO framework is approved, state involvement becomes minimal and FERC's role diminishes to a court of review for only the most serious disputes. FERC's long history in regulating power pools and early history with ISOs show that FERC will defer to the RTO management on most issues. Placing this much power and decision making authority in a RTO that lacks independence would be a recipe for disaster.

Embodied in the notion of independence is a recognition that the public interest, not the financial interests of generators or other
market participants, should influence RTO decision making. While independence is essential, it is not enough. Regulators need to be sure that incentives are in place to motivate the RTO to find and implement efficient and least-cost solutions that are consistent with the public interests. The RTO should be subject to a ratesetting regime that reconciles its financial success with least-cost operation and expansion of the transmission system.

The combination of the RTO's broad responsibility and the nature of FERC oversight means state regulators must take two actions. First, states must insist on independence. It is important that this occur at the outset when the structural framework and incentives that will drive RTO decision making are being fashioned. Second, regulators should insist that FERC's unwritten policy of deference be transformed into a clear statement indicating that the level of deference given to a RTO will be directly related to the degree of RTO independence, the nexus between the RTO's financial interest and the public interest, and the degree of approval received from state regulators.

2. Including Demand Side in Efficient Electric Markets

Efficient prices result from the constant interaction of supply and demand but, in most electricity markets, the dynamic interaction between price, supply and demand is indirect at best.

In particular, the demand side of the market does not play an active, robust role in setting market clearing prices. Effective pricing of actions that reduce demand is rarely done on a basis that permits direct competition with actions that increase supply. The demand/price relationship is also overlooked when pools and control area operators' rules take extra market actions to enhance reliability. Because this occurs, electric service will be more expensive, more polluting and less reliable than it should be in an efficient

competitive market. Those who are setting up RTOs should take positive steps now to harness demand-side resources both in energy markets and in assuring reliability.

Demand Bidding

An excellent description of RTO independence problems was put forth by a group of 22 state regulators who signed a "Declaration of Independence" in 1996 (Breaking the Bonds of Market Power, RAP Issuesletter March 1997.)

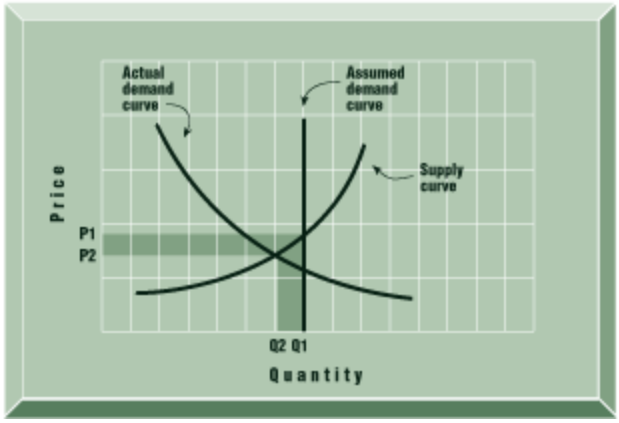
- In competitive electricity markets, all generators will benefit from high prices, while customers benefit from low prices.
- In competitive markets, higher prices achieved through any action, including control of the transmission system by any generator or group of generators, will benefit all generators.
- Decisions regarding transmission pricing, dispatch rules and new investments in the transmission system can add value to generation. An unnecessarily constrained transmission system will lead to overpriced electricity and excess profits for suppliers.
- Many techniques for leveraging transmission and system operation to add value to generation assets are complex, subtle and difficult to control through regulatory oversight.

Most RTOs, ISOs and power exchanges use supply-only bidding regimes. In the usual model of a competitive supply market, spot market prices are generally determined a day in advance by utilities, or in some regions by an ISO, power exchange or a similar entity. A supply curve is determined using either marginal costs or bid prices to rank order the plants beginning with the cheapest plants. The highest-cost resource called on in each hour sets the spot market price for all energy sold in that period. To the extent that there is any demand curve, it is an engineering construct based on factors such as yesterday's demand, the weather and the day of the week. It is not based on the utility customer's willingness-to-pay actual production costs. Consequently, even though the merit order dispatch of a utility or pool may rank supply resources according to cost, the intersection of the supply and demand curves while reflecting historic load patterns, expected weather and related factors are economically meaningless because the demand curve was not shaped by cost-based prices. (One should note that to the extent reliability costs are averaged across all hours, as is commonly required by regulatory policy in the US, the supply curve is also distorted. This distortion, too, causes an incorrect intersection of demand and supply in any given hour.)

RTO market rules should do better than this. (Beginning June 1, 2000 the PJM ISO will use supply and demand bidding.) A competitive market that does not give customers a meaningful opportunity to vary demand in response to price is a market in name only. If a stock market were to operate in a similar fashion, the exchange would forecast demand based on historical trends (i.e. forecast how many shares of Microsoft will be demanded tomorrow based on an historical average load curve of purchases) and then ask for bids from the holders of that stock. As is the case with spot power prices, the price of the stock

would be the price of the last bid needed to fill the forecast number of orders. Obviously, when considering the stock market, we would find the failure to take bids from both buyers and sellers to be a laughable error. Nevertheless, the same error and inexcusable loss of efficiency goes totally unnoticed and, therefore, uncorrected in our electricity markets.

The following figure illustrates the consequences of this process. The supply curve is derived from actual power plant costs or bids. The assumed demand curve is projected based on the engineering factors described earlier. This "curve" is a vertical line that is unaffected by price. The result is a price P1 and quantity Q1. Meanwhile, a real market would use the actual demand curve, reflecting how much power customers want at various prices. Using the actual demand curve, the price and quantity are P2 and Q2. The price is lower which saves all customers money, and the load is lower which makes for a more reliable system. The shaded area is the total dollar savings to all consumers.



To achieve these lower prices and lower demand, RTOs should establish bidding systems that reveal suppliers' proposed prices to customers in advance so that customers and load-serving entities (LSEs) can plan to manage loads in response to high (and low) prices. They should also allow LSEs to bid different levels of demand at different market clearing prices. Bidding systems of this type will establish markets that are genuinely competitive and will improve the reliability of the grid at lower cost than systems that focus on supplying a given load, regardless of the cost.

The Relationship Between Demand Response and Reliability

Load growth, particularly at peak, is a significant cause of our continuing reliability problems, yet most RTOs and reliability institutions do not explore load management and energy efficiency solutions. Reliability institutions that are dominated by transmission and generation owners have not been interested in pursuing reliability-enhancing measures in efficiency, load management or customer-owned generation, even when these solutions could be supplied at lower cost than new investments in turbines and wires. Independent RTOs, on the other hand, could support a comprehensive portfolio of reliability measures. (See *Least Cost Paths to Reliability*, RAP Issuesletter June 1999.) RTO governance structures and reliability rules should be established to make this possibility a reality.

Reserve margins, ancillary services and transmission upgrades are all important options, but maintaining reliability exclusively through a "wires and turbines" policy will be both unnecessarily expensive and harmful to the environment. RTOs should not be permitted to ignore the very real reliability benefits that can be delivered on the customer side of the meter.

It is hard to avoid the conclusion that profit has a lot to do with this myopia. Transmission owners would rather pursue incentive rates for investments in new reliability-related transmission links, while generation owners prefer to see increased reserve margin requirements and steeply rising price curves, which add scarcity value to generation far in excess of the marginal cost of production. This was the problem that regulators dealt with a decade ago by changed approaches to facility planning and rate setting. The rush to deregulation should not cause a new generation of regulators to repeat old mistakes.

Hourly Prices, Price Spikes and Demand-Side Bidding

During the summers of 1998 and 1999, electric markets in several US regions experienced short-term price spikes during which electricity sold at the margin for $1000 to $6000 per Mwh -- 50 to 100 times higher than the normal price. As these spikes demonstrate, electricity prices can be very volatile. One reason prices are so volatile is that consumers do not see the prices, and hence there is no demand response to temper increases.

In theory, all customers would see real-time prices that would enable them to make their own value decisions at all times, especially during very expensive peak periods. But, like it or not, most customers never see real-time prices, and in competitive markets, many customers will enter into fixed-price hedging contracts to avoid exposure to real-time prices.

Residential and small commercial customers do not have the sophisticated metering needed to price on a real-time basis. Large customers may have the needed meters, but most do not pay real-time prices, preferring instead the comfort of predictable prices. For large and small customers, high costs in a few hours each year appear as a small increase in average monthly prices. Thus, we find ourselves with a dilemma. We have labored hard to create a competitive, market-based system, but few, if any, customers actually see the resulting prices in a way that would trigger an expected market response.

Demand bidding is one way out of this dilemma. Assume a customer has signed a one-year contract to pay 6¢ per kWh. Further assume that at a peak hour the system operator is acquiring, or ordering LSEs to acquire power or imports at a cost of $1.00 per kWh. The fact that the actual cost is $1.00 per kWh during a given hour is of little concern to our customer. Yet the customer might jump at the opportunity to be paid 90¢ per kWh to curtail load (or to start up a standby generator), and if he does, all parties would benefit. In fact, if demand bidding of this type lowers the market clearing price at peak periods, the benefits of those lower prices will flow to every customer or LSE who is paying the spot price at that hour. In this case, the 10¢ per kWh savings from this transaction that will flow to other customers will dwarf the savings associated with the direct load reduction practiced by the bidding customer.

3. Transmission Access and Pricing Rules for Renewables

Two of the most plentiful and cleanest renewable resources in this country are wind and solar energy. Although there has been considerable regional experience with both and their declining costs are expected to make them increasingly economic in many more locations in future years, the enormous potential of these resources remains largely unexploited.

Notwithstanding the national interest in increasing our use of wind and solar resources, many RTOs/ISOs have adopted rules that have the effect of discouraging them. These rules are not aimed at explicitly discouraging renewables. Instead they exist either as attempts to address market power problems or simply as relics of how business has been done in the past. Three RTO issues fall into the "relics" category that are key to the ability of intermittent renewables to compete: imbalance penalties; distance-based,

capacity reservation transmission pricing; and the lack of secondary markets for transmission services.

Punitive imbalance penalties for units that were not available when scheduled provide a good example. Many RTO/ISO charge penalties (charges in excess of the costs imposed by imbalances) if a unit does not operate as scheduled the day before. These are called imbalance penalties, and they are imposed in addition to the market cost of the imbalance services which each generator must purchase if it has failed to meet its load as scheduled or if its load was larger than scheduled. Imbalance penalties have been designed to curb the ability of generators to manipulate market prices either by withholding capacity or via other ways of exercising market power -- activities that must, of course, be discouraged by the RTO.

However, the imposition of imbalance penalties to offset the underlying market power problem is devastating to intermittent resources such as wind or solar. These resources are price takers, not price makers. Imposing punitive charges on these resources is unnecessary, inefficient and moves in the wrong direction given that increasing the use of these resources is in our national interest. RTO efforts to address market power and gaming behavior should be accomplished through structural or behavioral remedies that do not automatically discriminate against intermittent renewable resources.

There are two ways to remedy RTO rules that are biased against intermittent renewable resources:

1. Find economic solutions that work for all resources and do not discriminate on the basis of inherent operating characteristics.
2. Exempt intermittents from the ordinary dispatch and scheduling rules and substitute a more appropriate set of rules designed specifically for them.

Transmission pricing provides a second example of the inherent problems for intermittent resources. The nation's extensive transmission system was built for reliability purposes. Yet competitive generation markets are pushing for it to be increasingly used for other, high-volume bulk power transfers. Transmission pricing was not a high priority issue when utilities were vertically integrated and wholesale transactions accounted for a minute fraction of electricity sales. In today's world, though, how we price these services is very important. Transmission pricing dictates what plants are run, what plants and wires are built, and where they are built.

Reforming transmission pricing has been a hotly debated issue. The many failed efforts to form RTOs/ISOs show that the focus is more on how a particular proposal shifts revenue and cost responsibility among the existing players than on how a proposal furthers efficiency and other important goals. Because renewable resources are, in a sense, the new kids on the block, it is no surprise that they have had little say in the debates.

Two aspects of renewables make them especially sensitive to transmission pricing decisions.

First, because renewables have to be located where the resource exists, most good wind and many larger solar sites tend to be located further from existing load centers and existing transmission corridors than other power plants. Second, wind and solar tend to have intermittent availability and capacity factors that are well below those for conventional fossil-fueled plants.

These plant characteristics mean good news and bad news for renewables. The bad news is renewables are at a severe disadvantage if transmission prices are based on distance or pricing is based on nameplate capacity rather than effective capacity. Also in the bad news category is that most other existing generators prefer these pricing approaches. The good news is the economics of transmission pricing is on the side of renewables. Transmission prices based upon "equivalent" capacity -- the average capacity actually used during peak periods -- leads to a more efficient use of transmission lines for all resources.

A second way to accomplish the more efficient use of transmission capacity while being user-friendly to intermittents is to strongly encourage a vibrant secondary market for all transmission services. The ability to buy and sell incremental transmission capacity right up to the moment of use not only provides intermittents a better opportunity to buy service that more closely meets their needs but also it also gives all generators the opportunity to fully optimize their use of transmission services.

Clean resources can do very well in competitive electricity markets provided they are not frozen out by inefficient transmission pricing and access rules, market operation and system expansion. They require a few basic, but essential, operational protocols:

- Incorporation of demand-side response in RTO rules
- Transmission tariffs based upon energy rather than capacity
- A vigorous secondary market for transmission services
- No pancaking of rates
- Avoidance of penalties for imbalance services
- Long-run, least-cost transmission system expansion
- A system of rate regulation (PBR) that is not based upon throughput

Because markets can provide more options, rules that rely more on market mechanisms and less on engineering criteria to set prices are better for clean energy.

Creating "secondary" markets for transmission services can help improve transmission pricing and reduce the burden placed on renewables. Having transmission access markets that clear on a monthly, weekly, daily and hourly basis would provide renewable and other resources the opportunity to buy and sell transmission services at actual market clearing prices. Unused transmission could be sold to another party, even moments before it was actually used. This could reduce the cost of reserving transmission capacity for generation which ultimately could not be used due to a drop in wind or a cloudy day. Likewise, it would allow a renewable facility that has an unexpected opportunity to run to secure last-minute transmission access without paying a rate unrelated to the actual market value of transmission at that

moment. FERC wants such a secondary market to occur and would undoubtedly welcome the support of state policy makers on this issue.

Distance-based transmission rates also make very little economic sense. Efficient transmission prices take into account the location of generation and load. Areas with high loads and little generation may have constrained transmission capacity and hence have high transmission costs, but the distance between any particular buyer and seller is a poor indicator of high cost. For example, locating generation in a constrained area lowers transmission costs and thus should result in a low or even negative transmission price. However, this generation has the same effect on transmission costs whether its output is sold locally or 100 miles away. Distance may be a simple gauge, but economically and environmentally, it is a poor measurement.

Conclusion

State utility regulators need to be closely involved in the creation of RTOs. The successful creation of open, efficient and truly competitive electricity markets depends largely upon what happens at the RTO level. Three issues in particular that deserve the careful attention of state regulators are: RTO Independence; Including the Demand Side in Markets; and Transmission Rules for Renewable Resources. RTOs that fail on these points will cause serious and costly flaws in the efficient electric markets policy makers are trying to create.

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