

SPOT MARKET PRICING OF ELECTRIC GENERATION

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In a current ratecase, the staff of the New York Public Service Commission has proposed a transition to spot market pricing for the generation component of a utility's retail electric rates. The staff proposal generally follows the "Poolco" approach. It is consistent with the possible divestiture of generation, but it assumes the retention of economic dispatch and an obligation to serve by the regulated utility. However, to avoid jurisdictional conflicts, the staff proposal is limited to a single utility which would purchase power on the spot market at avoided-cost rates. Retail sales rates would reflect these spot market prices for generation, along with embedded costs related to the remaining natural monopoly services. Customers and suppliers who wanted long-term price stability could negotiate bilateral price hedging contracts outside the regulatory arena. To avoid the disruptions of an immediate "flash-cut" to spot market prices and provide an opportunity for recovery of stranded costs, staff proposed a multi-year price cap plan tied to a ten-year phase-in of market prices. Retail rates would reflect a weighted average of "indexed embedded costs" (1995 prices indexed to changes in national average prices) and spot market prices (currently estimated by short-run marginal costs), with a gradual transition from embedded to market prices. In addition, staff suggested measures to refine the determination of spot prices and recognize locational (transmission) and reliability-related costs. The utility would pay each supplier the actual system cost avoided by the availability of that supplier. This "actual avoided cost" would be calculated at the end of each period, by means of a hypothetical dispatch assuming the supplier had been unavailable during the period. The payment of actual avoided cost is incentive-compatible: independent suppliers would maximize their profits by simply "bidding" their production costs and operating as directed by the utility's dispatcher. This approach was designed to minimize changes from current operating procedures, while transforming utility dispatch into an efficient spot market with the beneficial incentives of a second-price auction.

*Electricity Poolco Transmission*



within ten years. Under the staff proposal, the utility would continue to own and operate the transmission and distribution system under rate-of-return regulation, and would retain an obligation to serve all customers in its service territory. The utility would purchase power at spot market prices and sell power at tariff rates reflecting spot prices for power.<sup>1</sup> To avoid jurisdictional conflicts with the Federal Energy Regulatory Commission (FERC), the staff proposal would require the utility to purchase power on the spot market at actual "avoided cost" under the Public Utilities Regulatory Policy Act of 1978 (PURPA).<sup>2</sup>

To avoid the disruptions of an immediate "flash-cut" to spot market prices, the staff proposed a ten-year phase-in of market pricing. During the transition period, tariff rates would be based on a weighted average of spot market prices and an index applied to 1995 embedded costs. The index and phase-in were intended to provide an opportunity for the utility to earn a reasonable rate of return on its past investments. At the same time, tariff rates would be independent of the utility's actions. This would provide consistent incentives for the utility to minimize costs, and would help place utility-owned and independent generators on a level playing field.

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<sup>1</sup>This is conceptually similar to the "Poolco" approach, whereby generators would sell to a "Pool" and customers would buy from a "Pool" at spot market prices. In this case, the "Pool" would simply be the single utility.

<sup>2</sup>Normally, such purchases for resale would constitute "wholesale" purchases, and would be under FERC jurisdiction; however, PURPA delegated to states the setting of purchase rates at "avoided cost".



completed, embedded costs (and hence tariff rates) increased. The higher retail rates discouraged the very consumption which the new capacity was intended to meet. The result was uneconomic bypass, excess capacity, and the threat of stranded investment.<sup>3</sup>

#### Spot Market Pricing of Generation

While retail tariff rates are designed to provide a "normal" rate of return on assets, wholesale prices reflect a spot market price, in which utilities buy and sell energy on a short-term, or spot, basis.<sup>4</sup> The spot market reflects short-term marginal costs (fuel and variable operating costs for generators on the margin and customer outage costs). It offers no explicit recognition of longer-term maintenance and capital investment decisions. Nevertheless, spot market prices provide a consistent basis for longer-term maintenance and investment decisions as well. For

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<sup>3</sup>In the past, these problems were masked by technological progress and economies of scale in the generation of electricity. New plants had much lower operating costs than older plants, which more than offset the impact of adding these assets to the rate base. Rates declined almost continually in real terms (adjusted for inflation) until the 1970s, encouraging rapid load growth which quickly eliminated any excess capacity.

<sup>4</sup>Some customers are partially integrated into the spot market through interruptible rates and "real-time pricing." Because these rates are generally designed to provide roughly the same (net) revenues as regular tariff rates (i.e., they provide a "normal" rate of return), they are not fully market-based. They do, however, provide better "marginal" price signals than regular tariff rates: customers whose load increases (or decreases) will pay roughly the market price for the change in load (with reference to some base period level of load).



operates as a market for electricity, albeit one generally limited to generators owned by the utility.<sup>5</sup>

If electricity were an ordinary commodity, central dispatch could simply be replaced by posted prices. Individual generators and customers would offer to sell or buy quantities of electricity at each price, revealing the marginal cost (supply) and demand curves. The price could be adjusted until generation and load were in balance.

Unfortunately, electricity has some special features that make this approach problematic, especially with regard to local distribution. Because electricity cannot be efficiently stored, resources (generation and/or interruptible load) must be constantly adjusted to meet changing demand and/or generator outages. As a result, spot costs (short-run marginal costs) can undergo dramatic and unpredictable swings over a period of seconds. Moreover, spot costs can differ dramatically from one location to another, especially in the presence of transmission bottlenecks. It might prove very difficult for many suppliers and customers to respond effectively to these erratic prices. Thus a system of posted prices might create burdensome costs and serious reliability problems, especially at the distribution level.

Fortunately, there are alternative ways to operate a competitive market. One approach is to retain central dispatch,

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<sup>5</sup>Some customers are able to take advantage of interruptible rates, time-of-use rates, or "real-time" rates, e.g., hourly price signals. Also, some non-utility generators have negotiated limited dispatching arrangements with their local utilities.



(including hypothetical dispatches), the resulting payments cover the value of reliability (or power quality) as well as pure energy values.

#### Opening the Spot Market to Independent Power Producers

The reliable and efficient operation of the electric supply system could be most readily ensured and enhanced by integrating independent power producers (IPPs) into the utility's dispatch. This is especially important to NMPC, since IPPs provide a large and increasing share of its generation. Currently, most IPPs are not dispatched; this limits the services they can provide, and thus limits their value to the system. To provide the full range of services under dispatch, IPPs should provide their production costs and operating constraints to the utility. The utility could then dispatch all generators on a consistent basis. Payments to all would be based on avoided costs, determined ex post.

Efficient dispatch depends upon accurate knowledge of production costs and operating constraints by the dispatcher. This raises the question of whether generators would willingly supply such information. The answer will likely depend upon how they are paid.

If a generator were paid on the basis of its own reported production costs, it would have an incentive to report higher costs, in order to gain higher profits. Indeed, it would tend to



would maximize its profits by providing the most accurate information to the dispatcher.

However, if many generators in a region were owned by a single entity, they could misreport their costs and/or operating constraints in order to manipulate the market price and increase their collective profits. In short, they could exercise "monopoly power."

To mitigate this, the ownership of generators should be diversified. This could be achieved by having utilities "spin off" their generating plants into independent, unregulated companies. So long as their operation is coordinated through central dispatch, a diversified ownership should promote, not threaten, the reliable and efficient operation of the electric supply system.

#### Transmission Pricing

Transmission pricing is already accounted for in spot market prices for generation: it is simply the difference in spot prices between two locations.<sup>7</sup>

For example, suppose a customer is located next to a generator which is on the margin (thus running at partial capacity). Additional load from that customer can be served by simply increasing the marginal generator, and incurring its variable costs, say \$50/MWH.

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<sup>7</sup>See William Hogan, "Contract Networks for Electric Power Transmission", Journal of Regulatory Economics 4:211-242 (1992).



## Long-Term Energy Contracts

While some customers will welcome spot market pricing of energy, others will desire more predictable energy prices. A variety of contracts may be entered into by various groups - customers, suppliers, brokers, etc. The rules and conditions of these contracts will vary, but they can be structured so as not to interfere with the efficient operation of the spot market.

For example, customers could commit to purchasing specified quantities of energy at specified prices. The supplier would commit to selling these quantities to customers at the specified prices. The supplier would have the choice of generating the contractual quantities and paying the utility for transmission (wheeling), or purchasing the energy at the customer's spot market price (equivalent to paying the customer's tariff energy bill). In either case, the supplier would bear the price risk.

Of course, actual load would usually differ from the contractual amounts. These deviations should be priced at spot market prices (or tariff rates). In this way, customers could guarantee predictable total costs for the bulk of their purchases (the contractual amounts). However, these customers would not be permitted to "rate shop"--all additional purchases, and all reductions in purchases, would be made at spot prices. This ensures that embedded costs and other contractual commitments will not interfere with the reliable and efficient operation of the energy market.



However, there may be investments that are primarily beneficial to only a few suppliers or customers, so that a uniform charge on all would be inappropriate. In this case, the utility might sign contracts providing the beneficiaries with guaranteed price differences for specified quantities. For example, a utility might contract to purchase 100 MW from a supplier at its location and sell 100 MW at a customer's location for a fixed mark-up, intended to recover all expected transmission and distribution costs. (Alternatively, suppliers and customers could contract to sell to or purchase from a central location, as with natural gas hubs.) Once these contracts were signed, the utility (and/or general ratepayers) would have the incentive to make any desirable transmission investments.

#### Tariff Rates

In principle, all load could be integrated into central dispatch by allowing the dispatcher to interrupt loads whenever the market price got too high (i.e. above the customer's value of service). However, many customers will want to continue to purchase energy at regular tariff rates. To promote efficiency and avoid the inequities of rate-shopping, the energy component of tariff rates should reflect current marginal energy costs as closely as possible.

A full flow-through of energy costs would not give the dispatcher any incentive to reduce generation costs through more



Staff's goal was to shift the pricing of generation from embedded costs to market prices. The market value of generation was approximated by estimates of avoided generation costs (the same value currently used to price short-term power purchases from IPPs). "Competitive" costs were defined as the market price of generation plus the indexed TDC costs; these are also shown in Figure 2 (the market value of generation is given by the difference between "competitive costs" and "indexed TDC costs." The phase-in of market pricing would gradually shift tariff rates from the "indexed embedded costs" to "competitive" costs, as illustrated in Figure 2. During the transition period, tariff rates would reflect a weighted average of "competitive" costs "indexed embedded costs", with the weight on competitive prices increasing 10% each year.

#### Status of the Case

As in most rate cases, the utility and staff disagree over what constitutes "just and reasonable" rates. The company originally filed for approximately a 4.5% rate increase in 1995, while staff filed for approximately a 4.5% rate decrease in 1995, both based on forecasts of 1995 embedded costs (see Figure 3). Similar disagreements plague estimates of embedded costs in future years. The company filed a 5-year price cap plan tied to inflation, forecast to yield roughly 3% annual rate increases for 1996-99. Staff's transition plan was forecast to yield slight rate decreases during the same period. Both parties argued their rates



Figure 1

## Incentive to Report Accurate Costs Under Avoided-Cost Pricing

Supplier	Size (MW)	Cost (\$/MWH)
A	100	20
B	100	40
C	100	60

For Load = 50 MW				
B's Cost Reported	Running Units	Avoided Unit	Avoided Cost	B's Net Margin
10	B	A	20	-20
30	A	B	30	0
40	A	B	40	0
50	A	B	50	0
70	A	C	60	0

For Load = 150 MW				
B's Cost Reported	Running Units	Avoided Unit	Avoided Cost	B's Net Margin
10	B,A	C	60	20
30	A,B	C	60	20
40	A,B	C	60	20
50	A,B	C	60	20
70	A,C	B	70	0



Transmission Pricing Example

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Suppose the City has gas generation at \$70/MWH, and the Country has coal generation at \$50/MWH + start-up costs of \$100/MW for the first hour. A transmission line could be built for \$1000/MW, which would have 10% line losses. What are the marginal costs with and without the transmission line, should the line be built, and who should pay for it?

Without the transmission line, MC in the City is just \$70/MWH.

In the Country, MC is \$50/MWH + some portion of \$100/MW start-up costs.

If the load is a "spike", say 1 MW from 8AM to 9AM, then that load must bear the full \$100/MW start-up cost; so its total cost would be \$150.

If the load is purely "incremental" to a continuing load, say turning on 1 MW of load at 8AM instead of 9AM, then it does not bear any portion of the start-up cost, and the total cost of this "incremental" load would be \$50.

With the transmission line, MC between City and Country cannot differ by more than the 10% line losses. MC in both areas will depend on whether the load is a "spike" or is "incremental."

A "spike" load would be served by the City's gas generation, since this avoids coal's start-up costs. MC would be \$70/MWH in the City and \$77/MWH in the Country.

An "incremental" load would be served by the Country's coal generation. MC would be \$50 in the Country and \$55 in the City.

To determine whether the transmission line should be built, the present value of benefits must be compared to the cost. The City should compute the present value of all the "incremental" load savings of \$15/MWH (\$70-\$55). The Country should compute the present value of all the "spike" load savings of \$73/MWH (\$150-\$77). If the total PV savings is greater than \$1000/MW, build the line. City and Country should divide up the costs so both benefit - e.g. by the ratio of their respective benefits.

Ideally, to insure that all customers in the City and the Country benefit from the transmission line, the cost of the line should be recovered through charges reflecting the avoided costs. The Country's portion of costs could be recovered through "demand" charges, partially offsetting the savings on serving "spike" loads. The City's portion of costs could be recovered through "energy" charges, partially offsetting the savings on serving "incremental" loads.

*Electronics*