

Articles

"Buying Power—A Guide to the Competitive Electricity Market in Texas"

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Buying electricity once involved little more than purchasing from the incumbent monopoly supplier under standard tariffed rates with virtually no ability to negotiate over price, terms, power quality, or delivery options. On January 1, 2002, this will change. Customers served by investor-owned utilities (IOUs) in most of Texas will have the power to choose their electricity suppliers. While most residential and small commercial customers will shop among a handful of retail electric providers (REPs), offering standardized products, larger customers can negotiate highly customized electricity contracts with competitive REPs. A customer's knowledge of its specific electricity needs, how the market operates, the continued regulatory framework, and the cost components of the electricity rate will determine whether the customer or the REP strikes the best bargain.

Background

The most significant of the sweeping changes to the Public Utility Regulatory Act of Texas approved by the legislature in 1999 was the introduction of retail electric competition. If the prerequisites for competition are met, IOUs are required to separate their services into three unbundled businesses—a power generating company (PGC), a retail electric provider (REP), and a transmission and distribution company (TDC). The PGC and the REP will operate in what are intended to be competitive markets and will not be regulated.

Theoretically, the competition among PGCs to sell wholesale power and REPs to sell retail power will result in lower prices. For residential and small commercial customers, the legislature promised price protection, known as the "price to beat." To qualify, a customer must have a load 1 of less than 1,000 kilowatts. Affiliated REPs must charge these customers rates that are 6 percent lower than the bundled rates in effect on January 1, 1999.2 To attract new residential and small commercial customers, competitive REPs will attempt to undercut the price to beat. Customers with demand greater than 1,000 kW, however, have no price guarantees and must purchase power on the open market, negotiating to secure the best deal.

Buyer Beware

Specific electricity requirements must be determined in order for the customer to (1) purchase the most advantageous electricity products, (2) secure savings associated with to improve load shape to maximize savings. Most energy sold will be "full requirements" firm power, meaning that the REP will purchase generating capacity to serve that customer's load. Discounted "interruptible" power allows REPs to interrupt a customer's power flow when generation or transmission availability is scarce. A customer with self-generation capabilities should consider buying only backup or standby power. Customers may also be able to purchase specific blocks of power to serve "base" load 3 at lower prices and other blocks of power to serve "peaking" load at higher prices.

Other customers may have specific power quality needs. Some manufacturing customers, for example, are particularly susceptible to voltage or frequency excursions, fluctuations, or other wave distortions and thus may require power generated from a dedicate resource or delivered over particular portions of the transmission network.

Perhaps the most important information for a customer to know, historical and future "load shape"—the graphical depiction of electricity usage—is also often the most difficult to ascertain. A customer whose use is consistent has a flat load shape, which is extremely desirable in negotiating supply contracts. By contrast, a customer whose power needs vary according to season or time of day shows a very choppy load shape and is more difficult to serve because a REP must buy power to serve the peaks but does not want to be stuck with power that goes unused during the valleys. Some larger customers have specialized interval data recorder (IDR) meters that measure real-time demand levels, making load shape determination easy. Most, however, have more traditional meters that simply measure the number of kilo-watt-hours used and must rely on a standard "load profile" developed by the Electric Reliability Council of Texas (ERCOT).

Articles

Risk Allocation

The larger the load, the more customized the contract. In conceptualizing what type of deal to strike, large customers must decide how much regulatory risk to accept and how much to place on REPs.

Moving to an unregulated electricity market required the development and implementation of a large infrastructure of delivery protocols. ERCOT is primarily responsible for managing the electric grid in Texas, employing an Independent System Operator (ISO) to ensure that electricity is delivered fairly and efficiently. The existing transmission grid in ERCOT, however, was designed to serve load within each single utility's service area. In some areas, power cannot flow freely at all times because of transmission constraints. Without an independent party responsible for moving power around the grid, imbalances between load and generation could develop, causing wild swings in spot market prices. Such volatility is a serious hindrance to attracting REPs and could also result in reliability problems.

REPs fund the mechanisms that the ISO uses to keep the grid in balance and will attempt to pass the cost on to consumers. When a generation plant suffers an unscheduled outage with no reduction in its load, an imbalance between supply and demand develops. Without balancing mechanisms, the spot market in the constrained area compensates by creating a spike in the price. To alleviate such constraints and to create more stability in the retail market, ERCOT has implemented a detailed set of protocols. Not surprisingly, numerous fees attend the ISO's attempts to keep the market in balance. The Qualified Scheduling Entity (QSE) fee and the Commercially Significant Constraint (CSC) congestion management fee, provide good illustrations of regulatory risks that must be allocated in an electricity contract.

Every REP must be associated with a QSE, which matches load with generation and schedules the delivery of power through ERCOT. QSE services are competitive, and its fees are the subject of bilateral contracts with the REP. REP actions, such as failing to purchase sufficient wholesale power, can affect its QSE fees. If the REP attempts to pass the cost of the fee directly on to the customer, the provider's incentive to take care in securing generation to match load could be diminished.

ERCOT has established an initial \$20 million fund to which REPs will contribute amounts proportionate to the loads they serve. Once the fund is expended or on January 1, 2003, whichever is first, ERCOT will move to a direct assignment of CSC congestion management fees to pay generators who provide additional generation in one area to serve load that cannot be served by remote generation due to transmission congestion constraints. The conduct of REPs determines the level of these fees, so a pass-through to the customer is not an efficient allocation of incentives. Ultimately, customers and REPs must decide who bears the risk of the fluctuation of these costs.⁴

Because of the risk of paying these imbalance fees, REPs will generally require that customer electricity usage stay within a specified deviation of the load profile on which the electricity charge is based. If a customer exceeds the permitted amount, REPs may require an additional charge. Customers should know both their historical and projected future usage to minimize exposure to such additional fees.

Finally, a number of more generic contract issues should be negotiated, including the term of the contract, renewal terms, payment and billing, delivery of notices, credit and deposits, assignment and events of termination, dispute resolution, limitations of liability and confidentiality. None of these terms need to be standard; each can and should be negotiated to fit the needs of the customer.

Conclusion

With only a handful of REPs currently certified by the Public Utility Commission, the retail electric market in Texas remains in its infancy. Nevertheless, the new market is extremely complicated and pricing will not be immediately transparent. Because of the number and variety of ERCOT fees and the lack of regulation governing how they will be collected by the REPs, information is key to the striking of fair deals. At the very least, customers must have specific knowledge about their usage patterns and care-fully consider the allocation of risks associated with each component of the contract. In the future, a more standardized approach will certainly develop, but for now customers must proceed with caution to ensure that

Articles

competition works for them.

Notes

Amount of demand customer places on a generator.

Affiliated REPs are allowed to adjust the price to beat to account for increased fuel costs.

Base load refers to power that is always needed, such as for critical operations.

In addition to the regulatory charges, there are other "non-bypassable" charges that REPs must collect from customers as ordered by the Public Utility Commission of Texas. REPs must also pay tax assessments to the municipalities in which they serve customers and will recover these charges from customers.

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