

## **How Does the La Capra Northeast Market Model Work?**

- The La Capra Northeast Market Model models regional energy markets using PROSYM<sup>®</sup> software. PROSYM<sup>®</sup> is a utility dispatch simulation program that calculates a chronological dispatch of the various thermal, hydro, contract, and pumped storage sources in an electric system. We have specifically modeled the interconnected power markets of New England, New York State, PJM, Quebec, Ontario and New Brunswick.
- The La Capra model captures congestion dynamics within constrained areas such as Southwest Connecticut, New York City and Long Island, and well as areas with locked-in generation like Southeast Massachusetts/Rhode Island (SEMA/RI), Maine and the western zones of Upstate New York. Our model captures important pricing areas such as the New England hub in Central/Western Massachusetts, Northeast Massachusetts/Boston (NEMA/Boston) prices, and prices in the remaining zones in New York.
- PROSYM<sup>®</sup> simulates unplanned generation outages on a random basis using a Monte Carlo method. Based on the resources available each hour, the PROSYM<sup>®</sup> dispatch algorithm selects the lowest cost combination of generating sources and available imports to meet electricity demand in the region. In determining the hourly energy clearing price within a given TransArea, the model identifies for each hour, the highest-cost generating unit operating in that hour for each defined transmission area, including stations operating purely to provide spinning reserve. The highest-cost station's incremental cost is then calculated for both the off-peak period (incremental cost of fuel, variable operations and maintenance ("VOM") and emission allowance costs) and the on-peak period (also includes startup and fixed costs, recovered only during the hours of operation) to define the transmission areas' hourly energy clearing price. If the highest-cost supply unit happens to be located outside the transmission area in question, congestion charges and/or wheeling charges and are included as appropriate in determining energy price.
- Future energy prices will be a function of future loads, changes in the mix of generating sources over time - driven by unit retirements and new unit additions, fuel prices, emission costs, and transmission investments that improve the efficiency of the regional transmission grid.
- Delivered fuel prices for coal and residual oil are adjusted by station, based on historical relationships between the station average and the regional average delivered cost. Units with dual capability to burn both oil and natural gas are assumed to operate on the less expensive of the two fuels, except during May through October (i.e. ozone season), when they are assumed to operate on natural gas.
- Each generating unit providing energy to the spot market at given location (e.g., at the generator bus) in a given hour will receive a clearing price based on the locational marginal price (LMP) at that location (in New York, this is referred to

as locational based marginal pricing, or LBMP). The LMP or LBMP is the bid price(s) of the most expensive source(s) providing energy to that location in that hour, adjusted for the marginal cost of transmission losses if supply from the marginal source has to be transported over the transmission system to get to the location in question.

- For the pricing of wholesale electricity to load, the market is geographically segmented into pricing zones reflective of state boundaries in New England or zonal boundaries in New York and in some cases, further demarcated due to transmission constraints that limit the free flow of power between locations within a given state.
- Under this market structure, generation suppliers will have an incentive to bid at or near their short-run variable costs of providing energy.<sup>1</sup>
- Our analysis assumes that the average short-run variable cost includes fuel, VOM costs, and the cost of emissions allowances. This means that the full short-run marginal cost of a generating unit, including costs of start-up and inefficient part load operation, are included in the bid price.
- Our approach also assumes a competitive energy market, one in which no producer can materially control the price. To the extent that one or more participants can actually exert market power, prices during some hours could be higher.

#### **Environmental Adders**

- Although most representative are currently in compliance with the emissions standards for SO<sub>2</sub> and NO<sub>x</sub>, as defined in the 1990 Clean Air Act Amendments and stricter state-specific standards, we believe it is appropriate to reflect the value of emission allowances in the bid prices.
- Generators with excess allowances are permitted to sell these allowances to other utilities within the trading region (the entire U.S. for SO<sub>2</sub> and the eastern U.S. for NO<sub>x</sub>). Thus, the opportunity cost of generating energy in New England includes consuming allowances that could otherwise be sold.

---

<sup>1</sup> A generation supplier bidding below its short-run marginal costs runs the risk of losing money on every kWh generated if the supplier's short-run marginal cost exceeds the market clearing price. A generation supplier bidding above its short-run marginal cost is at risk of not being dispatched, and thus foregoing opportunities to earn operating profits (i.e., revenues that exceed short-run marginal costs). Thus, we expect that most generation suppliers in the energy market would bid hourly energy prices that approximate their short-run marginal costs.