POTENTIAL OPTIONS TO ADDRESS NYC CAPACITY MARKET

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The NYC capacity spot market continues to clear at the level of the bid/price caps on divested generation, equivalent to $105 per kW-year, despite the recent addition of about 1,000 MW of capacity. It appears that about 800 MW of NYC capacity has been economically withheld from the NYC market. If all of this additional capacity had been sold into the NYC capacity market, the NYC capacity spot price would have declined.[1] Moreover, the additional capacity sales could have decreased the statewide price, depending upon the bid prices of the accepted offers.[2]

NYC is a large load pocket, requiring about 9,300 MW of local capacity. Total NYC capacity is about 10,300 MW (including about 300 MW of SCRs), of which about 5,900 MW of local capacity is divested generation owned by three large suppliers (KeySpan, USPower Gen, and NRG). Each of these divested generation owners (DGOs) is pivotal, i.e. supply from each is needed to avoid a deficiency, and therefore each DGO has the potential ability to set the market price.

The NYC ICAP demand curve is relatively steep, declining from $14.34 per kW-month at the minimum requirement (9,300 MW) to $0 at 118% of the minimum (11,000 MW), a rate of almost $1 per 100 MW. By comparison, the statewide ICAP demand curve has a much shallower slope of about $1 per 700 MW (declining from $7.09 per kW-month to $0 over a range of about 4,700 MW). The relative steepness of the NYC demand curve means that the largest unregulated suppliers have an incentive to economically withhold by bidding at their caps, because the loss of sales would be more than offset by the higher price achieved on their

[1] The maximum impact on the NYC UCAP price for the June spot auction would have been a decrease of about $7.26 per kW-month (from $12.71 to $5.45), if all of the accepted NYC bids had been below $5.45.

[2] The maximum impact on the statewide UCAP price for the June spot auction would have been a decrease of about $1.28 per kW-month, from $3.25 to about $1.84 per kW-month, if the accepted ROS bids had been below $1.84. However, any statewide impact might be limited by the recently approved settlement in New England, which establishes a capacity price of $3.05 per kW-month beginning December 2006; at that time, arbitrage between New York and New England may place a floor on NYISO's statewide capacity price.

remaining sales. Note that this may not require collusive behavior, simply individual profit maximization.

The market power of the DGOs is mitigated by bid/price caps set at divestiture, which limit the capacity bids and prices (revenues) of the divested generation to a maximum of $105 per kW-year.[3] This is below the NYISO's estimated cost of new capacity, about $125 per kW-year. When supply is tight, the NYC market should operate competitively, with all available supply clearing in the market at a price set by the NYC demand curve (between $105 and $125 per kW-year). However, when supply is ample, the DGO's have an incentive to bid at their caps to keep prices from declining below $105 per kW-year. Thus the recent addition of 1000 MW of capacity in NYC has led to a significant increase in economic withholding in the NYC market, impacting both the NYC and statewide capacity markets. This outcome could continue until load growth and/or retirements tighten the NYC market (Poletti 1, at 888 MW, is scheduled to retire by the end of 2009).

In response to the potential for DGO withholding in the NYC market over the next few years, four options are discussed below: 1) Cap NYC capacity bids at "to go" costs (similar to PJM proposal); 2) Reduce the slope of the NYC demand curve; 3) Allow NYC suppliers to enter bilateral contracts; 4) Require unsold NYC capacity to be sold into the statewide market with revenues distributed to NYC load.

Option 1 (cap NYC capacity bids at "to go" costs) would be consistent with NYISO energy mitigation measures (AMP) which limit NYC bids to an estimate of each supplier's marginal energy costs (plus a relatively small threshold). This option would ensure that adding capacity would decrease the capacity clearing price. However, "to go" capacity costs are more complex to estimate than marginal energy costs. Moreover, if the existing price caps were removed then DGO supplies could earn revenues above $105 per kW-year during periods of tight capacity.

Option 2 (reducing the slope of the NYC demand curve) would reduce market power, encouraging DGOs to offer their capacity at prices below their bid/price caps. This should lead to a more competitive market, in which moderate increases in supplies lead to

[3] The annual cap has been translated to monthly caps that vary by season, with lower winter caps reflecting the greater NYC capacity in the winter months (due to more efficient cooling). Over time, the spread between summer and winter caps has widened, reflecting an increased spread between summer and winter capacities. However, the DGOs are still limited to $105 per kW-year overall.

moderate decreases in market-clearing prices. However, at any given clearing price, LSEs would have to purchase some additional quantities. In the short run (given a fixed amount of in-City generation), the net impact on LSEs would depend upon whether the potential reduction in price (due to lower-priced offers) offset the higher quantities purchased.[4] In the long run, lower price volatility could reduce financing costs and thus reduce the overall cost of in-City capacity.

Option 3 (allowing suppliers to sign long-term bilateral contracts) is another approach to encouraging all available supply to sell into the market. If a DGO were to sign a long-term fixed-price contract for a portion of its capacity, it would no longer benefit from a higher spot price on that contracted capacity. This could mitigate its market power, encouraging the DGO to offer its remaining supplies at more competitive prices. However, the DGO might simply charge LSEs a high price to sign such bilateral contracts, reflecting its initial market power. Indeed, in a tight market, competition among LSEs for below-market DGO capacity could permit DGOs to attempt to evade their bid/price caps, by tying capacity sales to high-priced energy; this was the concern that led to the prohibition on in-City bilateral capacity sales in the first place.

Option 4 (requiring unsold DGO capacity to be sold into the statewide market with revenues distributed to NYC load) would provide some benefits to both statewide and in-City loads. Under this option, the NYISO would first compute the NYC clearing price and quantity; then all unsold DGO supply would be automatically bid into the statewide market at $0, and the revenues rebated to NYC loads (just as DGO revenues above their caps are rebated). Besides providing some rebates to NYC loads, the additional statewide supply could lower the statewide price.

[4] For example, with a demand curve half as steep, the price-setting DGO might gain profits by lowering its offer price by $1/kW-month. Note that other suppliers would lose profits (assuming they were already selling all of their output, they would gain no sales and would lose revenues from the decline in price). LSEs could gain overall due to the lower price: while purchases could increase by a few percent, the spot price would decline by almost 10 percent, resulting in an overall decrease in payments.