4 October, 2001

Response to the NYISO ICAP Working Group

Michael Swider
Strategic Energy

During the September 24 ICAP Working Group meeting I made a presentation to promote the idea of replacing the current ICAP requirement with Directed ICAP payments made to those building new generation in the power pool. Part of the Directed ICAP presentation was devoted to refuting the contention, again reiterated in the presentation made by Norman Mah's of ConEd, that no generation owner can make sufficient revenues from the energy and ancillary services markets alone and therefore needs capacity payments to make a profit.

Like many presentations on the benefits of ICAP payments, Norman Mah's presentation was based on the assertion that a generation owner only receives revenues for a generation unit when that unit runs to provide energy or is selected to provide an ancillary service. That presentation completely ignores the value that can be received by extracting the option value from a generation unit. To make an honest argument for ICAP based on generator undercollections, you must include all revenues.

During my presentation there were two good questions that I would like to answer here. One question was "If you collect revenues from the forward market and the energy market, isn't that double counting?" The other question was "Does your example work if you use a New York forward contract rather than the Cinergy contract used in the presentation?"

For a producer, such as a generation owner, the option value is fundamentally the value of being able to cover a position in the spot market. The optionality value for the producer is usually captured through a forward contract price. When a generation owner sells a forward contract it is not selling its energy, it is making a commitment to deliver energy to a specific delivery point, without necessarily naming the source of the energy. If a generator has a 100 MW generator and sells 100 MW for delivery in a specific month, the generator could buy 100 MW at the same delivery point to satisfy its commitment, or it could generate the power and arrange for delivery.

If the generator sells 100 MW and later buys 100 MW back, it still has the opportunity to sell energy from the generator into the spot market. In our example, the generator sells power for more than its variable cost, and when the price in the forward market drops below the generator's variable cost, the generator buys 100 MW back, and can use this purchase to deliver 100 MW to satisfy its earlier sale. Now, if the price of power in the hourly market exceeds the generator's variable cost, it can sell into the hourly market. Obviously, this isn't double counting.

In our example, the last transaction before the delivery month was a buy, putting the generator in its original position from a physical standpoint of being able to deliver 100 MW into the spot market. If the last transaction before the month is a sale, then the generator is committing to use its generator to satisfy the commitment to deliver power for the month. That is, unless the generator buys 100 MW in the day-ahead, week-ahead or balance-of-the-month markets. As long as the generator offsets every sale with a purchase, it is free to sell into the spot market. Our example illustrates how a generator can extract significant value from the forward market before the delivery month ever arrives, and regardless of whether or not the generator runs in the delivery month.

For example: A generator (GenX, Capacity = 100MW) knows on 1 August 2000 that it can supply energy in September 2001 at Cost = $50/MW for all peak hours in a month. This price must include not only the marginal costs (fuel costs can be locked in through buying a call on fuel, and variable O&M should be known), but also the proportionate share of fixed costs. (Including capital costs because a supplier must make its debt payments between August 00 and September 01 or else it won't be there to supply. All these costs in a forward contract are referred to as *cost to carry.*) The generator owner obviously needs a profit, so for this example let assume that it is willing to sell forward to September 2001 On-Peak hours for $4/MW trading profit. The generator offers to sell an On Peak contract in NYC forward to September 01 at a price of $54/MW. The forward price on August 1 settles at $56.82/MW. GenX was *long* on energy in September 01 and sold a contract on its output for $56.82 that costs $50/MW to supply. Therefore, GenX can *tentatively* count on a profit of $207,328 (($56.82 - $50) x (16 hour x 19 days) x 100MW). The profit is only tentative because the generator may suffer a forced outage and not be able to cover its obligation in September 2001. Now several things can happen.

Scenario A: No more forward market trading.
The forward market provides no more opportunities to trade. Going into the month GenX has an obligation to serve 100MW at $56.82 per hour, however it can still receive additional revenues from the energy market. Assume each day GenX bids its short-run marginal cost of $45/MW into the DAM for the On Peak hours, but the DAM clears at $40/MW for a day, and GenX is not committed for that day. By having lower cost generating units supply its load obligation through the DAM, GenX is able to book an additional $8,000 (($45-$40) avoided cost x 16 peak hours x 100MW) in revenue for that day alone on top of the forward market revenue for that day. That's one way to make revenues in both the forward market and the energy market and without double counting.

Scenario B: Another forward market trade
Volatility in the forward market provides an opportunity for additional trading. GenX has sold 100MW at $56.82 and is willing to book $6.82/MWh in revenue if the forward price falls to $50 and it can cover its position with a contract. On September 1, 2000 the September 2001 forward contract falls to $31.48. GenX buys a 100 MW forward contract for $38.48 to cover the contract it sold for $56.82 and again has a long position in the market. GenX is able to book $770,336 (($56.82 – $31.48) x (16 x 19) x 100 MW)) in revenue for the month purely on the option value that its asset provides and

market volatility. If GenX makes no more trades, and goes long into the month of September 01 then it can sell its energy whenever the DAM or HAM exceeds their short-run marginal cost and make additional revenues that will contribute to paying for fixed costs and for profit.

Scenario C: Continual forward market trading
In the real-world GenX will continue to trade on every opportunity. Again, assuming that GenX has put a value of $4/MW on an option, GenX sells a contract when the forward price gets $4 above cost and buys when a forward contract is $4 below its long-run marginal cost to produce. Using a $4 trading bandwidth above and below $50, Gen X would have engaged in the following trades (the first two have already been covered in Scenarios A & B.)

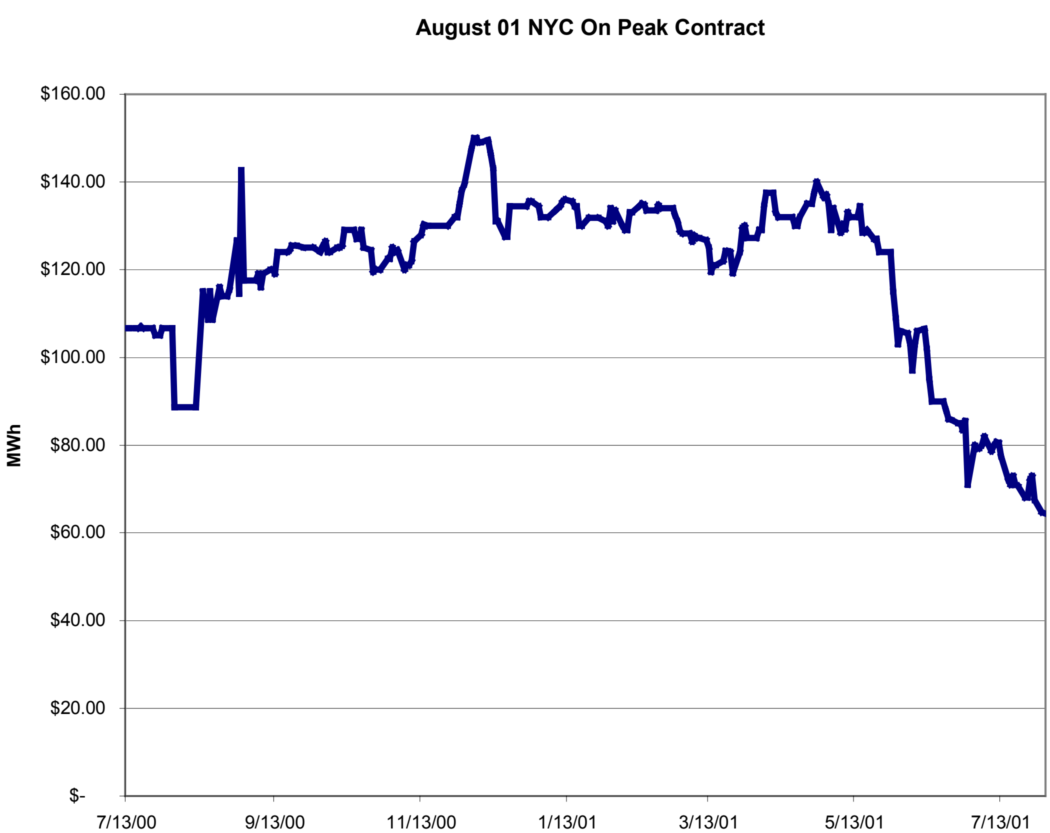
DATE	TRANSACTION	NET INCOME
August 28, 2000 -	sell 100 MW at $56.82	
Sept, 1, 2000	buy 100 MW at $31.48	$770,336
Sept 25, 2000	sell 100 MW at $81.24	
August 28, 2001	buy 100 MW at $45.75	$1,078,896
		$1,849,232

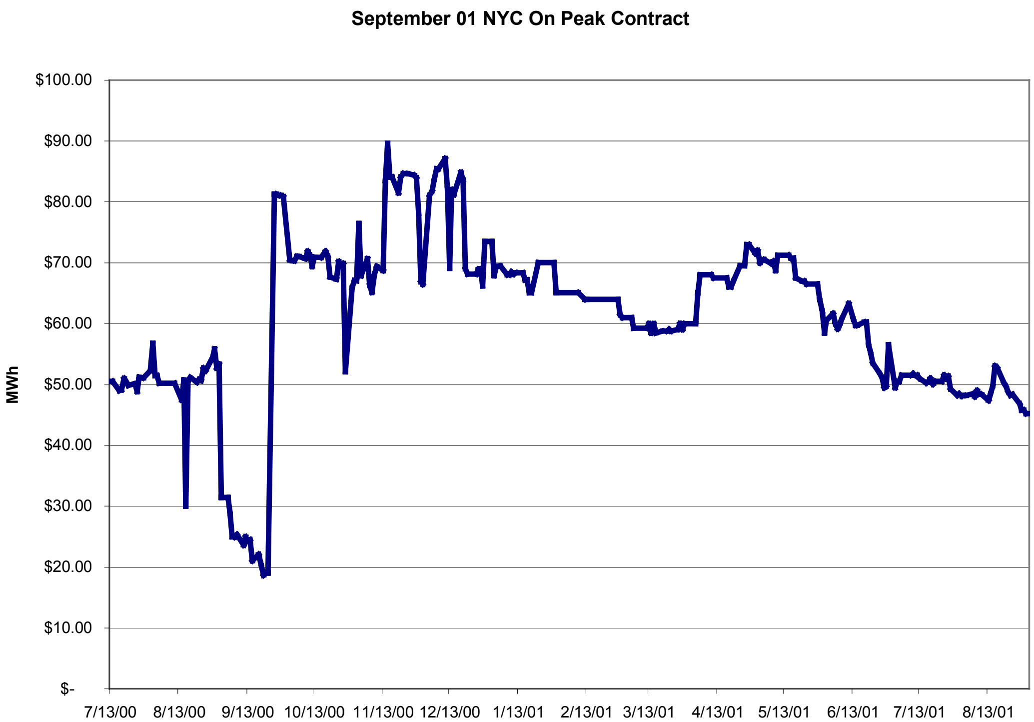
The total trading revenues for the month of September 2001 are $1,849,232, or $18.49/kW-month. These revenues are received regardless of how many hours GenX runs in the month of September[1]. This example demonstrates, using actual clearing prices for the NYC Sept 01 On Peak contract, that significant revenues are achievable outside of the energy market. A chart of the actual NYC data for the Sept 01 contract is attached. I have also attached data for Aug 01 for comparison purposes.

To have a serious discussion of ICAP reform we must give honest consideration of how the markets actually work and the true value of owning capacity. I acknowledge that even with revenues from the forward markets there may be units on the margin that are needed for reliability. A more rational approach may be to create a true forward reserve through Directed ICAP payment or forward reserve payments to marginal generators that commit to run, at an agreed upon strike price, and paid by the NYISO. Strategic Energy is willing to discuss other creative ideas for rationalizing the energy markets so that we can maintain reliability while allowing the markets to develop. However, we must first acknowledge how the market currently works before we start serious discussion of reforms.

[1] This example ignores the transaction costs, the compounding of interest and the cost of fuel hedging, but these are not significant relative to the effects of market volatility.

ATTACHMENTS




September 01 NYC On Peak Contract
MWh
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
7/13/00
8/13/00
9/13/00
10/13/00
11/13/00
12/13/00
1/13/01
2/13/01
3/13/01
4/13/01
5/13/01
6/13/01
7/13/01
8/13/01