Mark Younger Comments on
Energy and Ancillary Services Offsets
Numerical Calculations

by Mark Reeder
December 2, 2002
(typed April 4, 2003)

Note: The formatting does not match Mark Reeder's original because it was prepared by performing OCR on the PDF file.

Note: These calculations were performed by me only for the "Rest of State" capacity market. Steve Keller used a similar approach, and some of the same numbers, to calculate energy and ancillary services offsets for the New York City and Long Island capacity markets.

Overall ROS Offsets

Energy

- 2002 estimate of actuals [1] $ 7.50 per kW-year 2.52 for western GT
- adder for rules changes[2] 13.00
- adder for move from 23% 2002 actual reserve margin to 18% target reserve margin[3] 10.00$2.2 after corrections

Total energy $30.50 $22.70 east $17.7 west $30.50

Ancillary Services[4] 12.00 0.40

Total Offsets $42.50 per kW-year
$23.10 per kW-year East
$18.10 per kW year West

Comment: For Western GTs this value should be based on David Patton's $2.52 estimate for Western peaker revenues.

Comment: Corrections Provided Below

Comment: This a a value for a 10 minute non-sync reserve provider. The revenues need to be based on the 30 minute non-sync market. Market clearing prices for the last year show a significant drop in reserve prices. RTS market changes are expected to result in a further reduction in revenue for ancillary services. The market trials appear to confirm that 30 minute reserves will clear at zero in most hours. This is consistent with having all on-dispatch units provide latent reserves. If we are going to assume any revenue from this service then the $0.40/kW value calculated by Levitan study using recent data appears to be an upper bound of reasonable estimates.

ROS GT Value, Adjusted for Energy and Ancillary Services Net Revenues

The $42.50 per kW-year value is our best estimate of energy and ancillary services offsets for a GT operating in the upstate part of the New York market. For purposes of setting the height of the demand curve, we prefer to be conservative, i.e.., err on the side of a demand curve that is more likely to be too high than too low. This is accomplished by offsetting only half of the estimated energy and ancillary services net revenues in the calculation.

Annual net cost of GT = (annual carrying charges)
- (1/2 of energy and ancillary services net revenues)
= $85.00 – (.50)($42.50) (23.10 East; 18.10 west)
= $85.00 - $21.25(11.55 East; 9.05 west)
= $63.75 per kW-year

Comment: Need to use updated levilized GT Cost.

Comment: Mark Reeder generally describes the 50% weighting factor as being conservative. However, it is necessary to assure that the Minimum Installed Capacity Requirement will be met in all years.

An alternative approach to estimating a GT cost value that is designed to be slightly too high is to acknowledge only the energy and ancillary services offsets associated with the year 2002, a year in which a 23% reserve margin was projected. In other words, ignore the energy offsets associated with the tighter 18% reserve margin.
3
4

Alternate annual net cost of GT = (annual carrying charges)

---

[1] Provided by David Patton, applicable upstate, for a Frame 7A GT with a 12,000 Btu per kWh heat rate. These are net revenues, 12 months ending August 31, 2002.
[2] Provided by David Patton, covers changed market rule to allow demand response (EDRP) to set price and changed rule to allow an operating reserve shortage to set a real-time scarcity price.
[3] Estimated by Mark Reeder, using David Patton's parameters for the relationship between peak load levels and frequency of price spikes.
[4] Provided by David Patton, discussed by Andrew Hartshorn. For 12 months ending August 31, 2002.

- (2002 energy and ancillary services offsets, i.e.., a year with a 23% reserve margin) = \$85.00 - \$32.50 = \$52.50 per kW-year

Calculation of Adder for 23% vs 18% Reserve Margin

The energy and ancillary services offsets numbers provided by David Patton were for the 12 months ending August 31, 2002. According to the NYISO's 2002 Load and Capacity Data publication, the installed reserve margin for summer 2002 was expected to be 23%. As such, the 2002 numbers provided by Dr. Patton are assumed to come from an electric market that has a 23% reserve margin. The energy offsets value that sets the height of the Resource Demand curve needs to be stated in terms of an electric market that has an 18% reserve margin. The calculation described below provides an estimate of the increase in energy prices caused by a decrease in the reserve margin from 23% to 18%.

Comment: John Charlton claims that the 23% is too high and that the number is closer to 21%. At the 8/27 ICAP meeting John further clarified that the NYISO found that there were generally 500 to 700 MW (roughly 2% of capacity) of generation that were not ICAP providers and were not bidding into the NYISO markets. David Patton's analysis was based upon the supply curve and therefore did not include any generator's that did not bid into the market. Consequently, any adjustment for the market exceeding the minimum capacity requirement should be based upon the excess that was actually bidding (i.e. around 21% reserves).

In both 2000 and 2002, David Patton's annual reports provided estimates of how an increase in load creates an increase in price spikes. This information is used in the analysis below to relate reduced reserve margins to increased price spikes, which are then translated into an increase in energy prices.

Delta Price Spike Hours Per Delta Load:

From 2000 Patton report, price spike hours with Indian Point 2 in-service equal 8 hours; with Indian Point 2 out-of-service equal 33 hours (page 20). The delta price spike hours per delta 100 MW of load is

Comment: This value should not be used. It is a value for Eastern New York. A 100 MW change in eastern resources cannot be used to estimate the impact of a 100 MW change in statewide reserve margin. The 2004 Gold Book shows that over 30% of the NYISO peak load occurs Zones A-E. Page 18 of Dr. Patton's report shows that the Indian Point outage had verly little impact on Western New York prices.

(33-8) / 1,000 MW = 2.5 price spike hours per delta 100 MW.

From 2002 report, price spike hours with normal load equal 2; with extreme load (900 MW higher) equal 16 (page 25). This yields

(16-2) / 900 MW = 1.55 price spike hours per delta 100 MW.

Comment: This estimate of price spike hours is for eastern New York. The accompanying chart indicates that NYC is included because it shows the "load pocket effect" that resulted from reducing NYC OOM by solving for the load pockets. Any estimate of extreme prices that is based upon Eastern New York (including NYC and Long Island) will overstate the

A simple average of the above two values yields

price spike hours per delta 100 MW load = 2.025.

Comment: This value should be at or below the below the 1.55 extreme load estimate for an eastern resource to account for removing the LI/NYC factor. It should be further reduced for a western GT..

The methodology used by Dr. Patton in his reports freezes imports and exports. Relaxing this assumption would allow external power to enter New York to respond to added load, and would moderate, somewhat, the price increases caused by added load. The following downward adjustment is made to reflect this effect.

Adjusted price spike hours per delta 100 MW load =
(2.025) x (0.80) = 1.62, (1.55) x (0.80) = 1.24
Rounded to 1.60 1.24

Comment: Combining the 1.55 factor for extreme load conditions with Mark Reeder's .8 factor results in 1.24 hours per MW. (Note, Mark Reeder agreed at the 8/30 ICAP meeting that the .8 factor was not based on any analysis. It does not appear to be low enough to account for both the impact of excluding imports and for taking LI/NYC out of the calcuation.)

Net Energy Revenue Per Price Spike Hour:

Dr. Patton's 2002 report defines price spike hours to be "hours with projected prices greater than \$500 MWh" (page 25).

Given the $1000 bid cap, this means the price is in the $500 to $1,000 range. The midpoint of that range, $750, is used as the price that prevails, on average, during a price spike.

Comment: This price level would be very difficult to reach. Under RTS it would require a shortage of 10 minute reserves. It would be more approprate to use a number closer to $500 - $600 for these extreme hours.

A running cost of $100 is assumed for a GT. This will obviously depend on gas prices, but $100 is a reasonable proxy. The net energy revenues per price spike hours are

Comment: There are two problems with this assumption. First, David Patton's analysis already assumes that the GT is running when it is economic. The spike hours are likely to be hours where the GT is already running. Therefore the change is from the non-spike price (something under $500 to the spike price. That aside, the GT price should represent real-time gas costs and an allocation of start-up costs. An assumption of $150/MWh would be more appropriate.

$750 - $100 = $650 per hour.

__Added Price Spike Hours for 23% to 18%:__

The change in load associated with a move from a 23% reserve margin to an 18% reserve margin is calculated as follows:

23% - 18% = 5% change in reserve margin

5% change in reserve margin = (.05)(30,000 MW) = 1,500 MW

Comment: Should be (.03)(30,000 MW) = 900 MW

delta price spike hours = (1,500 MW) x (2.0 per 100 MW)(900)*(1.2 per 100 MW)
= (15 x 2)(9*1.2)
= 30 hours(10.8 hours)

Comment: Making a small adjustment for NYC/LI the factor should be 1.20 or less per 100 MW). It should be even lower if used for western capacity.

Comment: Round to 11

__Total Increase in Net Energy Revenues:__

Total increase in net energy revenues = (30 hours) ($650 per hour)
= $19,500 per MW-year
= $19.50 per kW-year
= $20.00 (rounded)

Comment: 11 hours times $400/hour = $4,400 per MW-year

Comment: $4.40 . Lower in the west.

An adjustment is made to be sure this parameter isn't overstated. This is accomplished by cutting it in half. As such, we err on the side of underestimating net energy revenue offsets.

Adjusted increase in net energy revenues caused by difference between 23% and 18% reserve margin = (1/2) ($20.00)
=$10 per kW-year

Comment: $2.2 per kW-year