UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. | Docket No. ER05-1410-000 and and EL05-148-000

SUPPLEMENTAL AFFIDAVIT OF BENJAMIN F. HOBBS
ON BEHALF OF PJM INTERCONNECTION, L.L.C.
ON THE SEPTEMBER 29, 2006 SETTLEMENT CAPACITY DEMAND CURVE

I, Benjamin F. Hobbs, being duly sworn, depose and state as follows:

My name is Benjamin F. Hobbs and I am a Professor of Geography and Environmental Engineering, and of Applied Mathematics and Statistics (Joint Appointment) at the Johns Hopkins University. I previously submitted an affidavit in this proceeding ("August 31 Affidavit") in connection with the August 31, 2005 filing by PJM Interconnection, L.L.C. ("PJM") to establish the Reliability Pricing Model ("RPM"). I also submitted a supplement affidavit on May 30, 2006 in response to the Commission's April 20, 2006 order on the RPM proposal ("April 20 Order"), addressing certain issues concerning the definition and analysis of alternative demand curves for capacity.

The purpose of this supplemental affidavit is to present an analysis of the demand curve agreed upon by the parties in the settlement filed on Sept. 29, 2006 (the "Settlement Curve"), and to discuss the adjustment of the assumed CONE in response to experienced capacity prices.

1. Analysis of the Settlement Curve

Assumptions. The Settlement Curve has been defined for the purposes of this simulation as connecting the following points:

- IRM-3%: 1.5*(72,000 –E/AS offset)/0.93 (in $/unforced MW/yr)
- IRM+1%: 1*(72,000 –E/AS offset)/0.93 (in $/unforced MW/yr)
- IRM+5%: 0.2*(72,000 – E/AS offset)/0.93 (in $/unforced MW/yr)

"IRM" is the installed capacity target of 115%. The "E/AS offset" is the amount that the curve is adjusted for energy and ancillary services gross margins that the benchmark turbine is assumed to be able to earn.[1] The curve to the left of IRM-3% is flat at the indicated price; the price is zero to the right of IRM+5%. All percentages are expressed in terms of the ratio of installed capacity to peak load. The capacity prices are expressed in terms of $/unforced MW/yr; to express these in $/installed MW, the denominator of 0.93—the expected unforced availability of turbines—is removed.

The analysis is based on the same approximating assumption as in the analyses in my August 31, 2005 and May 30, 2006 affidavits concerning the E/AS offset used to define the demand curve: that the offset is the same in every year. As explained on pages 25-26 of my August 31, 2005 affidavit, the average E/AS gross margin earned by the benchmark turbine during the 1999-2004 would have been $21,000/installed MW/yr under the "peak-hour dispatch" assumption.[2] This $21,000 value is the offset used to define the Settlement Curve in these simulations, according to the above definition of the curve. As an approximation, this value is treated as being the same in every year, rather than a rolling average of previous years as in the actual curve definition.

An assumption also needs to be made about what E/AS gross margins are actually earned in each year, as a function of system scarcity conditions. Reduced reserve margins will increase these gross margins, according to the 1999-2004 experience summarized in my August 31, 2005 affidavit. In this supplemental affidavit, the simulations assume that E/AS gross margins are

[1]The energy and ancillary service (E/AS) gross margin is defined as revenues net of variable operating cost. Thus, it can be viewed as the contribution of revenue to covering fixed costs.

[2] Under this assumption, the benchmark turbine (that is the basis of the CONE calculation) is assumed to be operated only during peak periods. In particular, turbines are assumed to be dispatched in four distinct blocks of four hours of continuous output for each block from the peak-hour period (between 8 a.m. and 11 p.m.) for any day when the average real-time locational marginal price is at least equal to the cost of generation (including start-up and shutdown costs) for at least two hours during each four-hour block. The blocks are assumed to be dispatched independently. This is a more realistic characterization of the dispatch, and therefore of the revenues, of the benchmark turbine for the purpose of calculating net CONE.

earned by the benchmark turbine according to the peak-hour dispatch assumption.[3] Therefore, consistent with this assumption, the benchmark turbine is assumed to earn E/AS gross margins in each year according to the lower of the two curves in Figure 3 of the August 31, 2005 affidavit, which is based on a peak-hour dispatch assumption for the benchmark turbine. That curve is $7600/installed MW/yr lower than the curve used in the base case simulations in my August 31, 2005 affidavit, where instead I assumed that the benchmark turbine would be operated in any hour in which the price exceeded the marginal operating cost.

The E/AS curve used in the below analyses is the sum of two components: (1) a $2400/installed MW/yr fixed E/AS revenue stream that does not depend on reserve margin and (2) a variable E/AS gross margin (termed "scarcity revenue" in the tables of results, *infra*) that depends on the actual reserve margin in the year. In comparison, the E/AS gross margin curve used in the base cases of the August 31, 2005 affidavit had a higher fixed component of $10,000/installed MW/yr but the same variable E/AS gross margin, and so yielded $7600/installed MW/yr more in E/AS revenue at any given reserve margin. Use of the latter curve, which assumes maximally flexible operation of the baseline turbine, including the ability to start any number of times and run for very short times, is less realistic than the peak-hour dispatch assumption with limited number of starts on a day and minimum run time.

To summarize the E/AS assumptions, the base case results I discuss below use the peak-hour dispatch-based E/AS gross margins for determining the average E/AS offset in the curves, while the actual E/AS gross margins earned in each year are simulated using the peak-hour dispatch assumption (the lower curve in Figure 3 of the August 31, 2005 affidavit). Additionally, all demand curves are evaluated under the assumption that the auction takes place three years ahead of the date in which the capacity is made available, rather than the four years assumed in my August 31, 2005 affidavit. All other assumptions are the same as in my August 31, 2005 base case

[3] See Footnote 2, *supra*.

analyses, including the use of twenty five simulations, each 100 years in length.

The sensitivity analyses are based on the same changes in assumptions described in Table 2 (page 50) of my August 31, 2005 affidavit.

Results. I now summarize base case results and sensitivity analyses for the Settlement Curve, as well as selected results for Curves 1, 3, and 4 (as defined in the August 31, 2005 Affidavit) for comparison. Curve 4 is the curve recommended by PJM in its August 31, 2005 filing, while Curve 3 is an alternative curve that is shifted 1% to the left from the recommended curve (measured in terms of installed reserve margin). Curve 1 is the "no demand curve" case, in which the demand curve is effectively a vertical line at the IRM, with the price capped at twice the CONE minus the E/AS offset.[4] Results for these curves allow me to characterize the relative performance of the Settlement Curve. First, Table 1 shows the base case results for the Settlement Curve and Curves 1, 3, and 4. Then Tables 2 and 3 provide results for Curve 4 and the Settlement Curve, respectively, under a number of sensitivity analyses.

[4] Curve 1 is evaluated in Table 1 under the assumption that all new capacity bids in at $25,000/unforced MW/yr, rather than the $0/unforced MW/yr assumed for Curves 3 and 4. The bidding assumption has only a small effect on the performance of Curves 3 and 4, as shown in my August 31, 2005 affidavit as well as in Table 2, *infra*. However, that assumption does impact the performance of Curve 1; in order to provide a conservative estimate of the relative deterioration in performance that results from using no demand curve, I use a bidding assumption for Curve 1 that is more favorable for that curve. If instead bids of new capacity are assumed to be zero, then the performance is instead as follows: 34.6% probability of meeting or exceeding IRM; -0.8% average reserve over IRM; and 145.6 $/peak MW/yr consumer payments for scarcity and ICAP.

Table 1. Summary of Base Case Results for Settlement Curve and Curves 1, 3, and 4: Average Values (Standard Deviations In Parentheses) (All Values in $/installed kW/yr, except Consumer Payments)

Curve	Reserve Indices		Generation Profit, $/installed kW/yr	Components of Generation Revenue ($/installed kW/yr)			Consumer Payments for Scarcity + ICAP $/Peak kW/yr
	% Years Meet or Exceed IRM	Average % Reserve over IRM		Scarcity Revenue	E/AS Fixed Revenue	ICAP Payment	
Curve 1. Vertical Demand Curve at IRM ("No Demand Curve")	52.2	-0.5 (0.9)	52.2 (93.2)	41.9 (72.5)	2.4	68.9 (50.3)	122.9 (99.9)
Curve 3. Alternate Curve with New Entry Net Cost at IRM (Shift Left to CT net cost at IRM)	90.2	1.1 (0.8)	14.0 (50.9)	25.8 (49.8)	2.4	46.8 (5.0)	81.6 (53.3)
Curve 4. Alternate Curve with New Entry Net Cost at IRM+1%	98.4	1.7 (0.9)	11.3 (43.0)	21.2 (41.4)	2.4	48.7 (6.6)	79.2 (44.8)
Settlement Curve	95.2	1.1 (0.7)	14.4 (49.4)	25.1 (48.2)	2.4	47.8 (6.3)	82.1 (51.7)

Table 2. Summary of Results for Curve 4 (August 31, 2005 Proposed Curve), Average Values

Curve	Reserve Indices		Generation Profit, $/installed kW/yr	Components of Generation Revenue ($/installed kW/yr)			Consumer Payments for Scarcity + ICAP $/Peak kW/yr
	% Years Meet or Exceed IRM	Average % Reserve over IRM		Scarcity Revenue	E/AS Fixed Revenue	ICAP Payment	
Base Case	98.4	1.7	11.3	21.2	2.4	48.7	79.2
Max Price = Net Cost multiplied by 1.5	96.8	1.6	11.8	21.9	2.4	48.5	79.7
Max Price = Net Cost multiplied by 1.2	94.0	1.5	12.6	22.9	2.4	48.3	80.4
Price drops to zero at IRM+10%	98.8	1.7	11.1	21.1	2.4	48.6	79.0
Original Curve: No chopoff	98.8	1.7	11.1	21.1	2.4	48.6	79.0
Low Percent CT added when profit is equal to cost	97.4	1.6	12.4	21.7	2.4	49.3	80.4
High Percent CT added when profit is equal to cost	97.6	1.7	11.5	21.5	2.4	48.6	79.3
10,000 bids for new capacity	98.6	1.7	11.2	21.2	2.4	48.6	79.0
25,000 bids for new capacity	98.7	1.7	11.1	21.1	2.4	48.6	79.0
44,000 bids for new capacity	98.8	1.7	11.0	21.0	2.4	48.6	78.9
44,000 bids for new, 20,000 for existing capacity	98.8	1.7	11.0	21.0	2.4	48.6	78.9
Zero risk aversion (0.5)	97.0	2.1	7.5	20.2	2.4	45.9	74.9
High risk aversion	90.6	1.2	23.1	28.0	2.4	53.7	91.7
High rate of decay in weights	100.0	1.6	10.5	21.1	2.4	48.1	78.3
Low decay in weights	87.4	1.6	17.8	24.3	2.4	52.0	86.1

Table 3. Summary of Results under Settlement Curve, Average Values

Curve	Reserve Indices		Generation Profit, $/installed kW/yr	Components of Generation Revenue ($/installed kW/yr)			Consumer Payments for Scarcity + ICAP $/Peak kW/yr
	% Years Meet or Exceed IRM	Average % Reserve over IRM		Scarcity Revenue	E/AS Fixed Revenue	ICAP Payment	
Base Case	95.2	1.1	14.4	25.1	2.4	47.8	82.1
Low Percent CT added when profit is equal to cost	92.2	1.1	15.3	25.7	2.4	48.2	83.1
High Percent CT added when profit is equal to cost	95.5	1.2	14.4	25.4	2.4	47.5	82.1
10,000 bids for new capacity	95.2	1.1	14.4	25.1	2.4	47.8	82.1
25,000 bids for new capacity	95.2	1.1	14.4	25.1	2.4	47.8	82.1
44,000 bids for new capacity	94.2	1.2	13.8	24.8	2.4	47.6	81.5
44,000 bids for new, 20,000 for existing capacity	94.2	1.2	13.8	24.8	2.4	47.6	81.5
Zero risk aversion (0.5)	87.8	1.6	9.5	24.6	2.4	43.5	76.5
High risk aversion	65.7	0.0	38.2	43.6	2.4	53.2	107.2
High rate of decay in weights	99.7	1.2	14.1	24.6	2.4	48.0	81.8
Low decay in weights	84.4	1.0	17.3	27.7	2.4	48.2	85.1

The qualitative conclusions concerning the comparison of Curves 1, 3, and 4 (Table 1) and the effects of alternative assumptions upon the Curve 4 results (Table 2) are the same as in my August 31, 2005 affidavit. Thus, the change from a four year-ahead to three year-ahead auction does not change the general conclusions.[5]

Turning to the comparison of the Settlement Curve results with Curves 1, 3, and 4, I make the

[5] However, it should be noted that the average "Consumer Payments for Scarcity + ICAP" are higher than reported in the August 31, 2005 affidavit for Curves 1, 3, and 4. The reason for this is that the average consumer costs includes only scarcity E/AS costs, and not the fixed component. When the assumption of a peak-hour dispatch-based E/AS curve is used in the simulation, the fixed component of the E/AS gross margin to turbines shrinks from $10,000/installed MW/yr to $2400/installed MW/yr; therefore, for a turbine to break even, it must obtain more revenue from other sources, namely capacity payments and variable (scarcity) E/AS revenues. In equilibrium, therefore, the latter increase by approximately $7600 per installed MW per year. This change also translates into an increase in calculated "Consumer Payments for Scarcity + ICAP" by roughly that much; the increase is not exact, because the equilibrium solutions change slightly and, more importantly, Consumer Payments are expressed on a $/peak MW load/yr basis, not $/installed MW/yr. Note that the total cost paid by consumers does not actually increase; this increase in "Consumer Payments for Scarcity + ICAP" is matched by a decrease in nonscarcity-related energy and ancillary services payments.

following conclusions. When the Settlement Curve is defined using a fixed average E/AS offset (rather than a rolling 3 year average, as actually would be used), Table 1 shows that its performance in terms of Consumer Cost is comparable to Curve 3, achieving a value of 82.1 $/Peak kW/yr (as opposed to 81.6 and 79.2 for Curves 3 and 4, respectively, under the base case assumptions). Its performance in terms of "% Years Meeting or Exceeding IRM" is 95.2%, which lies between Curves 3 and 4 (90.2% and 98.4%, respectively).

These differences between the Settlement Curve and Curves 3 or 4 are very small compared to the gulf between their performance and that of Curve 1 ("No Demand Curve"), which performs much worse. In particular, in comparison to the Settlement Curve and Curves 3 and 4, Curve 1 results in 50% higher consumer payments for scarcity and ICAP, and roughly half the probability of meeting or exceeding the IRM. Therefore, I conclude that the differences among Curves 3, 4, and the Settlement Curve are minor compared to the benefits of moving from the vertical curve case (analogous to the present PJM ICAP system) to RPM.

The sensitivity analysis results for the Settlement Curve, in terms of how alternative assumptions affect Consumer Payments, are qualitatively similar to Curve 4. The Settlement Curve is, however, somewhat more sensitive to risk aversion assumptions (because it has a slightly more vertical aspect than Curve 4). But this difference is not large compared to the differences between the vertical curve (Curve 1) results and the sloped demand curves.

Thus, based on this analysis, I conclude that the Settlement Curve's performance would likely be similar to that of Curve 4, which was recommended by PJM in its August 31, 2005 filing, and much better than the vertical demand curve (Curve 1).

2. Updating Procedures for the Settlement Curve: The Empirical CONE

In this section, I address the settlement's "Empirical CONE" procedure. Given that any estimate of CONE is uncertain and that generation technology is evolving, it is desirable to have a predictable and transparent procedure for changing the assumed CONE when bidding behavior and market clearing prices indicate that actual capacity costs may differ significantly from the assumed CONE. Predictability and transparency is helpful in establishing confidence in the market and in facilitating the creation of a forward market for capacity rights. It is also desirable that such a procedure not result in large swings in CONE that reflect short-term market behavior rather than changes in technology. The proposed procedure, in which the demand curve's CONE is changed by no more than the minimum of (1) 10% and (2) 50% of the difference between the assumed CONE assumed and the Empirical CONE (as defined in the settlement), is a reasonable compromise for the following reasons. First, it will yield much less year-to-year variation than the situation where the demand curve's CONE was set equal to the Empirical Cone. Second, the curve's CONE will nevertheless still move over time in the direction of the Empirical CONE if bidding behavior indicates a persistent shift in peaking technology costs.

This concludes my affidavit.