UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER14-______

AFFIDAVIT OF BENJAMIN F. HOBBS
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Benjamin F. Hobbs and I am the Theodore K. and Kay W. Schad Professor (and Chair) of Environmental Management and Professor of Applied Mathematics and Statistics (Joint Appointment) at the Johns Hopkins University located in Baltimore, Maryland. I am also the inaugural, Founding Director of the Johns Hopkins University Environment, Energy, Sustainability, & Health Institute established in 2010. My business address is 7107 Wardman Rd., Baltimore, Maryland 21212. I am submitting this affidavit on behalf of PJM Interconnection, L.L.C. ("PJM").

I. QUALIFICATIONS AND EXPERIENCE

2. I have been a member of the faculty of Johns Hopkins University's Department of Geography & Environmental Engineering since 1995, for which I have also served as chairman. I have also held a joint appointment in the Department of Applied Mathematics & Statistics since 1995. Previously to joining the Hopkins faculty, I was Economics Associate at Brookhaven National Laboratory, National Center for Analysis of Energy Systems (1977-1979). I then joined the Energy Division of Oak Ridge National Laboratory as a Wigner Fellow from 1982-1984. Between 1984 and 1995, I was on the faculty of the departments of Systems Engineering and Civil Engineering at Case Western Reserve University. While there, I was named a Presidential Young Investigator by the National Science Foundation.

3. I earned a Bachelor of Science degree in a self-designed program in environmental science and mathematics from South Dakota State University in 1976, and a Master of Science degree in Resource Management and Policy in 1978 from the College of Environmental Science & Forestry of the State University of New York. My Ph.D. was awarded in 1983 in Environmental Systems Engineering from Cornell University, with minors in Operations Research and Resource Economics.

4. My research and teaching concerns the application of systems analysis and economics to electric utility regulation, planning, and operations, as well as environmental and water resources systems. A particular focus of my research is the use of engineering-economy models to simulate electricity and emissions allowances markets, recognizing transmission and other technical constraints and imperfectly competitive behavior by market participants. My present research focuses on power market modeling, capacity market design, analysis of pollution policies under uncertainty and climate change, and decision analysis applications in ecological management. I have published three books and over 150 refereed papers on these topics. My work has

received best paper awards from several professional societies. I have on-going research projects sponsored by the National Science Foundation, the US Department of Energy Consortium for Electricity Reliability Technology Solutions, Minnesota Pollution Control Agency, and the National Institutes of Health.

5. I have had visiting appointments at the Helsinki University of Technology, University of Washington, and ECN (Netherlands Energy Research Center). In 2009-2010, I was an Overseas Fellow at Churchill College and a Senior Researcher at the Electricity Policy Research Group ("EPRG") at the University of Cambridge. I continue as a Research Associate of EPRG.

6. In the last ten years, I have been a consultant to Booz & Company, the UK Office of Gas & Electricity Markets, the Maryland Department of the Environment, the Louisiana Coastal Protection and Restoration Authority, Lawrence Berkeley Laboratory, FinGrid (Finnish Network Operator), the U.S. Army Corps of Engineers (Baltimore District), the Brattle Group, the U.S. Department of Energy (Energy Information Agency), and the Maryland Power Plant Research Program. My consulting has addressed a number of topics in power and water systems planning and market design. From 1996-2001, I was a consultant to the FERC Office of the Economic Advisor on market design and market power mitigation. I am on the editorial board of several journals in electric power engineering and economics. These include *Competition and Regulation in Network Industries*, *Economics of Energy & Environmental Policy*, *Energy Economics*, *EURO Journal on Decision Processes*, *Journal of Energy Markets*, *Journal of Energy Engineering (ASCE)*, *IEEE Transactions on Power Systems*, *Power Engineering Letters (IEEE)*, *Energy, The International Journal*, and *The Electricity Journal*. I served as Area Editor for Environment and Natural Resources for *Operations Research* between 1996 and 2005.

7. I am Chairman of the Market Surveillance Committee of the California Independent System Operator, which I have served as a member since 2002. I am also on the Public Interest Committee of the Gas Technology Institute. I am presently Scientific Advisor to the Policy Studies division of the Netherlands Energy Research Center. I was an Institute Associate of the National Regulatory Research Institute, Columbus, OH from 1989-1995. I hold the rank of Fellow in the Institute of Electrical and Electronics Engineers and the Institute for Operations Research and Management Science.

II. PURPOSE OF THIS AFFIDAVIT

8. I previously submitted an affidavit in connection with the August 31, 2005 filing by PJM before the Federal Energy Regulatory Commission ("FERC" or "Commission") to establish the Reliability Pricing Model ("RPM"), in Docket No. ER05-1410-000. I also submitted (1) a supplemental affidavit on May 30, 2006, in Docket Nos. ER05-1410-000 and EL05-148-000, in response to the Commission's April 20, 2006 order on the RPM proposal, addressing certain issues concerning the definition and analysis of alternative demand curves for capacity, and (2) another supplemental affidavit on September 29, 2006, for the purpose of presenting an analysis of the demand curve agreed upon by the parties in the settlement filed on September 29, 2006, and to discuss the adjustment of the

assumed Cost of New Entry ("CONE") in response to experienced capacity prices. Among other things, my prior affidavits compared vertical demand curves against downward sloping demand curves and found that the sloped demand curves better satisfied resource adequacy objectives and yielded lower average cost.

9. Earlier this year, PJM asked me to assess whether RPM market changes implemented in 2011 might be blunting the effects of the downward sloped demand curve for the largest class of capacity resources, *i.e.*, those available throughout the year (as distinct from certain resources that are available only four or six months of the year, and that have other limits on their required response). This affidavit, reflecting work I conducted and presented to PJM and PJM stakeholders in August and September of 2013, sets forth my analysis. Specifically, in this affidavit, I address (1) whether the 2011 rule changes, including setting a minimum requirement for capacity resources, available throughout the year ("Annual Resources"), have effectively subjected the clearing of those resources to a vertical demand curve; and (2) if so, what are the likely effects of that vertical demand curve on the resource adequacy performance and cost of the RPM market's procurement of those Annual Resources, compared to the performance and cost resulting from a sloped demand curve.

III. CONCLUSIONS

10. The imposition of a fixed Minimum Annual Resource ("MAR") Requirement, together with a large quantity of lower priced offers from Demand Resources (as defined by PJM) with limited availability, has resulted in a demand curve for Annual Resources that is, in effect, vertical. As a result, Annual Resources have lost the price stabilization, reliability and consumer cost benefits of the sloped demand curve that I described in my 2005 and 2006 RPM affidavits. To restore those benefits for Annual Resources, which have the highest level of reliability due to their absence of seasonal or response limitations, a slope can be introduced in their effective demand curve.

11. To analyze the potential long-run benefits of restoring the slope to the effective demand curve that Annual Resources face, I have applied a version of the dynamic capacity market model used in my 2005-2006 RPM affidavits. The model is simplified so that a range of assumptions concerning costs, investor behavior, and energy demand can be simulated. As in my 2005-2006 affidavits, I conclude that the sloped curve robustly outperforms the vertical demand implied by the MAR Requirement, in terms of generally having a higher probability of installed Annual Resources meeting the requirement and lower consumer costs. Under none of my simulations does the vertical curve outperform a sloped curve in terms of these two crucial objectives.

IV. DEMAND CURVE FOR ANNUAL RESOURCES IMPLIED BY CURRENT MARKET RULES

12. In the affidavits referenced above, I presented arguments that implementation of a sloped demand curve in RPM would result in more stable capacity prices and reserve margins, lower average costs for consumers, and improved resource adequacy (as measured by the average reserve margin) than the vertical demand curve that was, in effect, established by the fixed capacity obligation and deficiency penalty approach used by the previous PJM Installed Capacity ("ICAP") market. I documented the formulation and assumptions of a simulation model that I developed that represented decisions to invest in peaking generation capacity over time in response to levels and variability of energy and capacity prices. My conclusion that a sloped demand curve for capacity in RPM would be superior to a vertical demand curve flowed directly from the assumptions that future energy and capacity prices are uncertain; that willingness to invest depended on forecasts of those uncertain prices, which in turn reflect recent price experience; and finally, that generator investors are risk averse. Investors are risk averse if they prefer an investment with a less uncertain return to one with a more uncertain return, if both have the same long-run average return. The findings of my model that a sloped demand curve is superior in terms of consumer cost and resource adequacy were robust with respect to changes in particular assumptions for the model's parameters concerning price and investor behavior, as long as there is some uncertainty and investors are risk averse to some degree. The Commission acknowledged these benefits of a sloped demand curve when it accepted the settlement that resolved the earlier proceeding and permitted PJM to implement RPM.

13. In early 2011, the Commission approved RPM rule changes that established three different types of capacity products, with varying availability characteristics. These include Limited Demand Resources ("Limited DR"), Extended Summer Demand Resources ("Extended Summer DR"), and Annual Resources (including Annual Demand Resources, Generation Capacity and Energy Efficiency Resources). Limited DR is available only from June through September of each Delivery Year, and must be available for at least ten interruptions during that period, for a maximum of six hours in duration between 12:00 p.m. to 8:00 p.m. Eastern Prevailing Time. Extended Summer DR is available only June, July, August, September, October and May of each Delivery Year, for an unlimited number of interruptions, for a maximum of ten hours in duration between 10:00 a.m. and 10:00 p.m. Eastern Prevailing Time. Annual Resources, other than Annual Demand Resource, are available throughout the year, and have no limits on the frequency of their response. Annual Demand Resources must be available for interruptions throughout the entire Delivery Year, for a maximum of ten hours in duration, between 10:00 a.m. and 10:00 p.m. Eastern Prevailing Time for the months of June, July, August, September, October and May, and between 6:00 a.m. to 9:00 p.m. Eastern Prevailing Time for the months of November through April. Under the rules approved in 2011, PJM sets a minimum requirement for Annual Resources in the RPM Auction clearing process. If needed to procure sufficient quantities of Annual Resources to meet the minimum requirement, a higher price will be paid for Annual Resources in

the RPM Auction, based on the marginal Annual Resource offer needed to meet the minimum requirement.

14. In my opinion, the 2011 rule change has indeed resulted in the implementation of a form of vertical demand curve for the clearing and procurement of Annual Resources, with adverse implications for long-run resource adequacy and consumer costs. Under the current implementation, as long as the RPM Auction procures sufficient Annual Resources to satisfy the MAR Requirement and a sufficient combination of Annual Resources and Extended Summer DR to satisfy the Minimum Extended Summer Resource ("MESR") Requirement, any procured capacity in excess of those requirements up to the intersection with the sloped demand curve can be provided entirely by the Demand Resources with limited availability. This will occur when the more Limited DR is offered at a lower price than offers from incremental quantities of Annual Resources or Extended Summer DR that are in excess of the minimum requirements. It is my understanding that PJM has conducted three of its principal three-year forward capacity auctions under these rules, and that for some of the locational markets in these auctions, procurement has indeed shifted to the more limited resources once the requirement was met for the Annual Resources**.**

15. This situation has two undesirable implications:

a. Under this approach and these conditions, the Annual Resources offered are, in effect, cleared against a vertical demand curve defined by the MAR Requirement.[1] Further, the sloped demand curve beyond the MAR Requirement has no impact on the cleared quantities and clearing prices of the Annual Resources that provide PJM with the highest level of reliability due to their absence of seasonal or response limitations. In this situation, the price received by Annual Resources is determined by the intersection of their overall offer (supply) curve with the MAR Requirement, which, as a fixed quantity, acts as a vertical demand curve with a price cap. Consequently, Annual Resources no longer derive the benefits of price stabilization provided by a sloped demand curve as identified in my 2005 and 2006 analysis and recognized by the Commission. This effective vertical curve is analogous to PJM's ICAP market structure before RPM which assessed a penalty on load serving entities that failed to demonstrate capacity equal to or in excess of expected peak loads plus a stated reserve margin. Just as the fixed-reserve and penalty approach failed to recognize the value of capacity procured beyond the fixed reserve level, PJM's present approach is not adequately

[1] As I understand the current rules, a similar vertical demand curve also can arise at the minimum requirement for the combination of Annual Resources and Extended Summer Demand Resources, *i.e.*, if the price received by annual capacity is set by the intersection of the latter requirement with the supply curve defined by offers from Annual Capacity plus Extended Summer DR. This occurs when that price exceeds both (1) the price defined by the intersection of Annual Capacity offers and the MAR Requirement and (2) the price defined by the intersection of the supply curve consisting of all offers to the RPM market (including Limited DR) and the RPM demand curve. On the other hand, if the price defined by the intersection of Annual Capacity offers and the MAR Requirement is higher than the other two prices, than the MAR Requirement vertical demand curve defines the price received by annual capacity.

recognizing the value of Annual Resources procured beyond the MAR Requirement and results in less stable prices than a sloped curve.

b. The sloped portion of the demand curve beyond the target reliability requirements (MAR and MESR Requirements) is utilized only to clear additional quantities and determine the clearing price of the capacity resource types having the lowest availability and response requirements (lowest reliability value). The long-run reliability and cost benefits provided by a sloped demand curve relative to a vertical demand curve are, in effect, unavailable to the capacity resource type having no seasonal or response limitations and highest reliability value (*i.e.*, Annual Resources) and instead maintained for capacity resource types having the lowest availability and response requirements and lowest reliability value (*i.e.*, Limited DR and Extended Summer DR).

V. COMPARISON OF VERTICAL AND SLOPED DEMAND CURVES FOR ANNUAL RESOURCES

16. I have adapted the model I used in my 2005-2006 affidavits for the purpose of evaluating the impact of the effectively vertical demand curve for Annual Resources implied by the MAR Requirement. In particular, I have compared the performance of a vertical demand curve with sloped versions of a demand curve for Annual Resources that has the same slopes as the PJM RPM sloped demand curve for all resources. In other words, I compare the present situation in which Annual Resources effectively faces a vertical demand curve with a situation in which the slope of the curve has been restored. As in my 2005-2006 affidavits, the performance indices include the probability of achieving capacity targets (in this case, the MAR Requirement for Annual Resources), the average amount of Annual Resources, and costs to consumers. Consumer costs are based on the cost of capacity, amount of capacity procured, and energy and ancillary service gross margins earned by all generation in excess of the running cost of new combustion turbines, the most expensive new resource on the system. (This resource is termed the PJM Reference Resource.) I used the latest data available from PJM to specify the input parameters used in the model (such as average demand growth, growth variability, CONE, and combustion turbine fuel costs). I also performed sensitivity analyses with respect to a number of input assumptions concerning supply offers by peaking generation plants, risk aversion, and other behavioral parameters that are uncertain in order to ascertain whether the sloped demand curve maintains its superior performance over the vertical demand curve when those general assumptions change. As I stated previously, the goal of the analysis is to assess the ability of the demand curve to create a stable capacity market, to meet the reserve requirement each year, and to minimize the costs to consumers.

A. Basic Assumptions and General Methodology

17. Capacity additions in electric power systems are a dynamic process that are influenced by past and anticipated price behavior, and in turn affect future prices through the interplay of supply and demand. The model executes chronologically one year at a

time, simulating the formation of capacity offers by existing and new entrants that are assumed to be combustion turbines with the same cost and operating characteristics as PJM's Reference Resource. The supply offers from existing resources and new entrants interact with the RPM demand curve in the Base Residual Auction for the PJM Region as a whole, without considering Locational Deliverability Areas. The willingness to invest is based upon forecast gross margin (revenue minus variable costs) streams for similar turbines. The model focuses on investments in combustion turbines, for which capacity payments make up a greater fraction of revenues than is the case for other types of capacity. Gross margin projections used in formulating offers for new capacity are informed by five years of experienced margins, consistent with how time series-based forecast models are used to project prices. The willingness to invest, as reflected in new capacity offers in the RPM Auction, is assumed to drop due to risk aversion if the variability in prices translates into significant uncertainty in the revenue stream without increasing average returns.

18. The analysis was based on the same approximating assumption as in the analysis in my previous affidavits concerning the energy and ancillary services ("E&AS") offset used to define the demand curve: that the offset is the same in every year and not adjusted in response to observed offers and market outcomes. These assumptions are implemented in a spreadsheet model that simulates decisions in a series of years. These assumptions combine in the model to show that use of demand curves that increase the stability of prices and provide adequate returns to investment would increase investment in the capacity market and help meet the reserve target at lower costs to consumers.

19. Alternative demand curves (vertical and sloped) are evaluated under the assumption that the RPM Auction takes place three years ahead of the date in which the capacity is made available. Thus, the analysis has been simplified compared to the most elaborate of the 2005-2006 analyses by focusing only on the three year-ahead Base Residual Auction. I used twenty-five simulations, each 100 years in length, as in the 2005-2006 analyses. These simulations are randomly created using a Monte Carlo method to generate shorter-term variations in energy and ancillary services prices arising from weather-induced load fluctuations, as well as longer-term variations in demand growth due to load growth variability.

20. The model is not intended to be a highly detailed representation of the actual mechanics of RPM, nor the current fleet of generation resources in operation. Rather, its purpose is to provide insights on the long-run effects of differently sloped curves upon the dynamics of generation investment in combustion turbines that define the Reference Resource in RPM, given the fundamental assumptions of investor aversion to risk, the importance of new resource investment in the future resource mix, and the presence of large uncertainties about demand growth, weather, and prices. As I stated in my 2005 affidavit, all models are necessarily simplifications of reality, and because many of the parameters of the model cannot be known with certainty, no single set of outputs should be treated as being a definitive statement on the quantitative performance of a demand curve. Instead, I conduct numerous sensitivity analyses around key parameters to determine the patterns of their influence on the model results, and the robustness of any

conclusions about the relative performance of different curves. While the model necessarily simplifies capacity market decisions and impacts, the model is useful for the purpose of understanding qualitative dynamic effects such as whether the relative ranking of different demand curve alternatives is robust under a wide range of assumptions. The model is not accurate enough to make precise quantitative predictions, but its intent is to illuminate several qualitative decisions that must be made when designing capacity markets.

B. Key Input Parameters

21. For these simulations, the combustion turbine capital cost is the annual cost of a combustion turbine based upon the gross Net CONE used in RPM for the Reference Resource. Revenues are from PJM's energy, ancillary services, and RPM markets. Uncertainties are introduced in economic growth and weather. The model determines the profitability of combustion turbines needed to meet the reserve requirement. The time step is one year.

22. The input parameters were updated based on the most recent data available from PJM. The key input parameters are shown in Table 1. The 'target annual capacity' is derived as follows as a percentage of Forecast Peak Load:

Forecast peak load = 100%.
Reliability Requirement
= Forecast Peak Load * Forecast Pool Requirement = 100% * 1.0902 = 109%.
Limited DR/Extended Summer DR Reliability Target
= 10.5% (10.9% UCAP Value).
MAR Requirement
= Reliability Requirement - Limited DR/Extended Summer DR Reliability Target
= 109% – 10.9% = 98.1%.

This MAR Requirement of 98.1% of Forecast Peak Load is used as the 'target annual capacity' for Annual Resources by which I evaluate the resource adequacy performance of both the vertical and sloped demand curve for Annual Resources only. This target defines the quantity intercept of the vertical demand curve I modeled. Meanwhile, I used 101% of this target to derive Point (b) on the sloped curve for my simulations (*i.e.*, a quantity of 99% of the peak load), as shown in Table 1 below, which is analogous to the quantity "IRM + 1%" on the sloped demand curve consistent with the current RPM Auction design. Below, I include, for illustrative purposes, depictions of the vertical demand curve (Figure 1) and sloped demand curve (Figure 2) used in my base case analyses.

Table 1 – Key Input Parameters

Key Input Parameters to 2013 Capacity Market Analysis by Hobbs

Parameter		Comments
Planning Parameters/CT Costs		
Gross CONE, CT based, ICAP $/MW-Year	$139,392	Planning Parameters 2016/2017
Gross CONE, CT based, ICAP $/MW-Day	$381.90	Planning Parameters 2016/2017
Pool-Wide Average EFORd	5.69%	Planning Parameters 2016/2017
Installed Reserve Margin (IRM)	15.6%	Planning Parameters 2016/2017
Forecast Pool Requirement (FPR)	1.0902	Planning Parameters 2016/2017
Demand Resource (DR) Factor	0.955	Planning Parameters 2016/2017
Energy Revenue Offset, $/MW-Year	$23,415	2010-2012 based on PJM avg LMP
Ancillary Services, $/MW-yr	$2,199	Per Tariff
Energy & Ancillary Services (E&AS) Offset, $/MW-year	$25,614	
Net CONE, ICAP $/MW-Year	$113,778	Gross CONE - E&AS Offset
Net CONE, ICAP $/MW-Day	$311.72	Net CONE $/MW-yr / 365
Net CONE, UCAP $/MW-Day	**$330.53**	Net CONE ICAP/(1-Pool-Wide Average EFORd)
CT Operating Cost, $/MWh	$48.68	Consistent with E&AS offset.
Forecast Peak Load/DR Targets/Target Capacity		
Forecast Peak Load, MW	**152,383**	Planning Parameters 2016/2017
Reliability Requirement	166,128	Planning Parameters 2016/2017
Limited+Extended Summer DR Reliability Target, % Peak Load	10.5%	Planning Parameters 2016/2017
Limited+Extended Summer DR Reliability Target, UCAP MW	16,658	
Minimum Annual Resource Requirement, MW	149,469	
Minimum Annual Resource Requirement, % Forecast Peak Load	**98.1%**	Used as Target for Demand Curve
Vertical Demand Curve Parameters		
Maximum UCAP Price, 1.5 Net CONE, $/MW-year	$180,964	UCAP less than the Target
Minimum UCAP Price, $/MW-Day	$0.00	UCAP greater than the Target
Sloped Demand Curve Parameters		
Point (a) UCAP Price, 1.5 Net CONE, $/MW-year	$180,964	
Point (b) UCAP Price, Net CONE, $/MW-year	$120,643	
Point (c) UCAP Price, 0.2 Net CONE, $/MW-year	$24,129	
Point (a) UCAP Level, MW (IRM - 3%)	95.3%	Expressed as fraction of Forecast Peak Load
Point (b) UCAP Level, MW (IRM + 1%)	99.0%	Expressed as fraction of Forecast Peak Load
Point (c) UCAP Level, MW (IRM + 5%)	102.8%	Expressed as fraction of Forecast Peak Load
Load Parameters		
Forecast peak load growth, %/year	1.3%	First 10 years growth from 2013 forecast.
Load forecast uncertainty (weather normalized vs. forecast)	1%	
Weather uncertainty (actual peak vs. weather normalized)	4%	

Figure 1 – Vertical Demand Curve Depiction

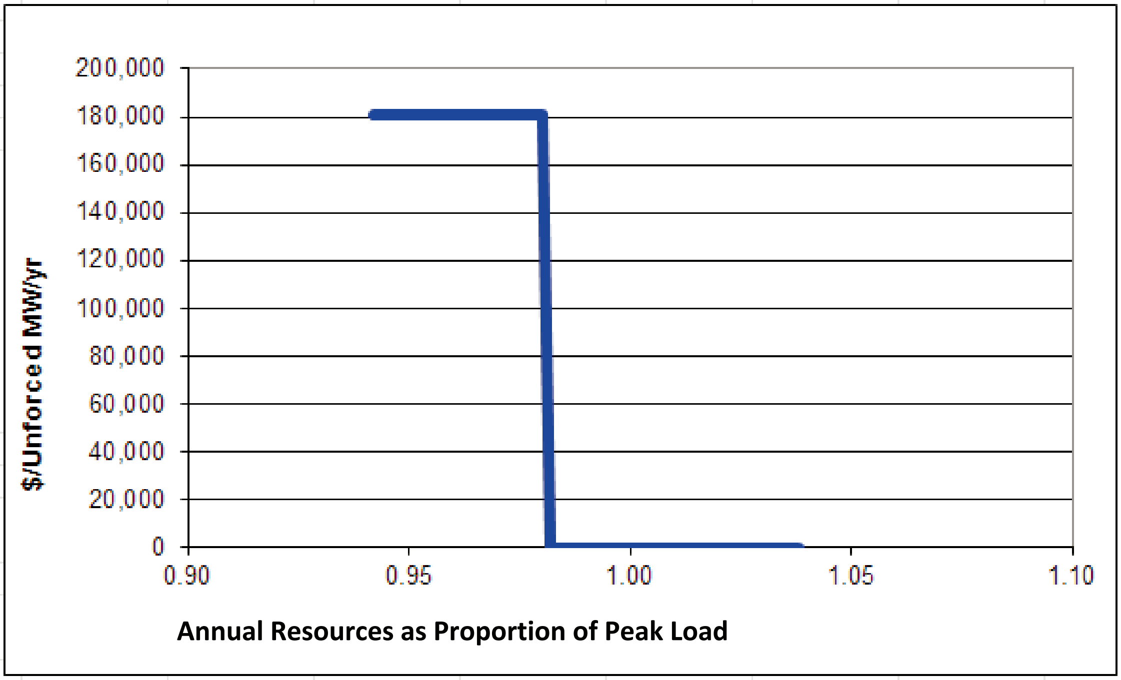
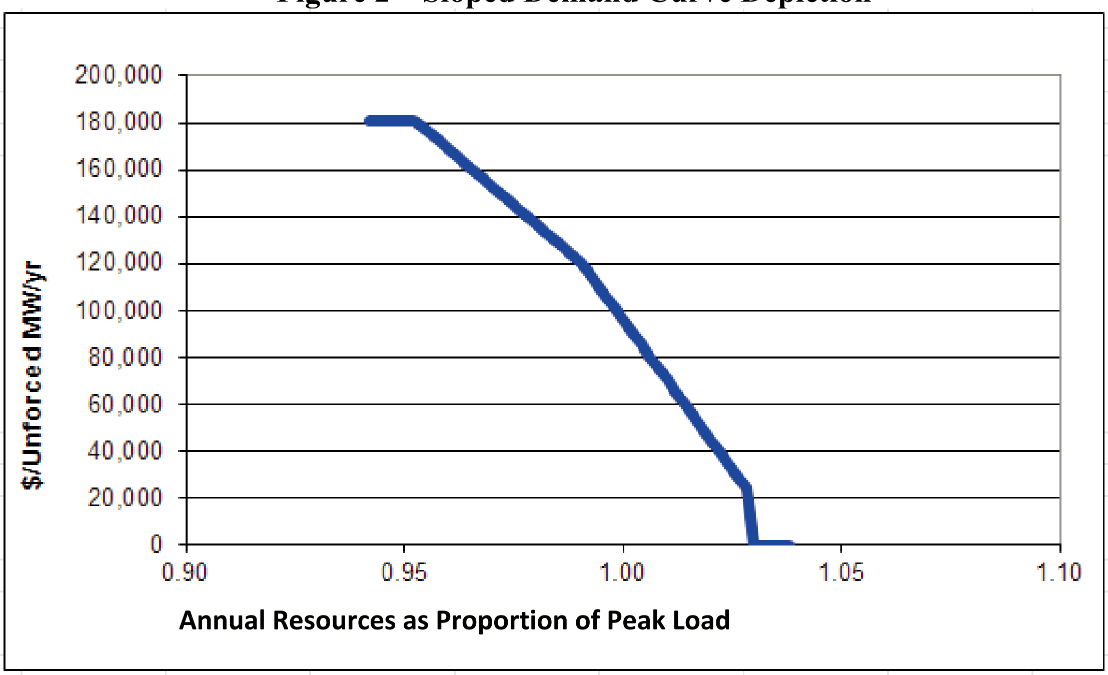


Figure 2 – Sloped Demand Curve Depiction



23. My results, which I present in the following section and detail in Table 2 below, compare vertical and sloped effective demand curves for Annual Resources (Figures 1 and 2) under a base case set of assumptions concerning the demand curve, offer behavior, degree of risk aversion, weighting of recent revenues in the price forecasting algorithm, and degree of uncertainty in load forecasts. The vertical curve pays $180,964 per unforced megawatt of capacity per year to Annual Resources if the amount provided is less than the MAR Requirement, and an amount equal to the intercept of the offer curve

and the vertical demand curve (located at the MAR Requirement, which is 98.1% of the forecast peak load). The sloped curve is horizontal to the left of point (a) (at 95.3% of the peak) at $180,964 (equal to 150% of the assumed CONE), then is interpolated linearly between points (a), (b), and (c) (the coordinates of (b) and (c) are shown in Table 1 above), and finally has a vertical segment between (c) and the quantity axis. After presenting the base case results, I then present results under several alternative sets of assumptions to assess the robustness of my conclusions. The following general assumptions were used in the base cases:

Bid price for new capacity = $0/MW of unforced capacity/year up to the maximum amount that generators are willing to build
Upper limit on capacity additions = 7% (under highly favorable financial conditions)
Risk aversion coefficient = 0.7 (compared to 0.5 which represents risk neutrality, in which only expected returns matter to investors)
Relative weight on recent combustion turbine revenues = Higher (as opposed to an equal weight on most recent 5 years of revenues)
Load forecast uncertainty = 1% (standard deviation of weather normalized peak vs. forecast)

C. Results: Base Case

24. To summarize results for the base case assumptions, which are detailed on the first two rows of Table 2 below, first, I calculated two reserve indices for the sloped and vertical curves:

Percent of years Annual Resources met or exceeded target annual capacity (MAR Requirement)
= 42% for vertical demand curve; 96% for sloped demand curve.
Average amount of Annual Resources in excess of target annual capacity (MAR Requirement), expressed as a percentage of peak load
= -0.62% for vertical demand curve (*i.e.*, below the target, on average); 1.24% for sloped demand curve (*i.e.*, above the target).

25. Next, I divided the revenue impacts of each demand curve into two portions: payments through RPM ("RPM payments"), and payments for energy and ancillary services in excess of the marginal running cost of new combustion turbines ("E&AS gross margin"), which can be interpreted as scarcity revenues arising from scarcity pricing mechanisms or dispatch of units whose marginal costs are greater than new turbines, or a combination of those factors. I normalized these by dividing by the amount of ICAP. For the vertical demand curve:

E&AS gross margin = $96/MW-Day
RPM payments = $350/MW-Day
Total = $446/MW-Day

26. In contrast, the model shows that the revenue required by the risk-averse generators in order to invest decreases by $50/MW-Day under the sloped demand curve:

E&AS gross margin = $57/MW-Day
RPM payments = $339/MW-Day
Total = $396/MW-Day

27. Furthermore, the standard deviations (year-to-year) of the revenue streams are much less under the sloped curve than under the vertical curve, as Table 2 below shows. For instance, under the base case assumptions, the standard deviation of ICAP payments under the vertical curve is $202/MW-day, while for the sloped curve it is $29/MW-day.

28. The more stable but lower revenues under the sloped curve also result in lower but more stable profits, net of investment costs:

Profit for New CT = Gross Margin minus Capital Cost
= $64/MW-Day (standard deviation = $268/MW-day) for vertical curve
= $14/MW-Day (s.d. = $59/MW-Day) for sloped curve

29. The fact that the standard deviation of profit exceeds the average reflects the frequent occurrence of years in which profits (gross margin minus capital costs) are negative.

30. Finally, impacts on consumer payments are expressed by dividing the sum of total E&AS revenues (in excess of the running costs of new turbines) and RPM payments by the annual energy demand expressed in megawatt-hours (MWh) (assuming an annual load factor of 60%, equal to the ratio of the average load to the peak load).

Consumer payments = $30/MWh for vertical curve
= $27/MWh for sloped curve

31. In summary, the sloped demand curve results in increased investment to help meet or exceed the reliability target. This is because capacity prices and total revenues are more stable; risk averse generators are willing to accept lower profits when they are much more stable. Both components of combustion turbine profits (RPM payments and E&AS revenues) are smaller, the latter because of the effect of larger capacity margins on the supply-demand balance in the short-term energy markets. Note also that both long-run averages for combustion turbine profits and consumer payments are lower with the use of the sloped demand curve than with the use of a vertical demand curve. These general conclusions are consistent with those of my 2005-2006 affidavits.

D. Results: Sensitivity Analyses of General Assumptions

32. I changed the general assumptions made in the base case as shown below to perform sensitivity analyses of the above results. These sensitivity analyses included the following cases:

a. The new capacity bid price was increased to $50,000/MW-year ($136.89/MW-day) and $100,000/MW-year ($273.78/MW-day), simulating submission of an offer curve with non-zero prices. This supply curve has similar behavior as a sloped supply curve, in that it stabilizes prices for both vertical and sloped demand curves, the reason being that it puts a floor under the range of possible price responses over the quantity range of interest (values of offered capacity between the existing capacity and the maximum total capacity offered). A sloped supply curve whose prices lie between $50,000/MW-year and $100,000/MW-year would be anticipated to yield results between those resulting from the two offer curves based on those prices.

   These cases can also be interpreted as situations in which the lowest price that Annual Resources would obtain is bounded from below by Limited and Summer Extended DR offers of $50,000 and $100,000/MW-year, respectively. This is because when ample Limited and Summer Extended DR is offered at a non-zero price, the lowest price that annual capacity could obtain is that demand resource offer. This would be the case, for example, when new turbine capacity offers at $0/MW-year and the amount offered is in excess of the MAR Requirement but not the MESR Requirement; in that case, the price that Annual Resources receives is not $0/MW-year, but instead is the price set by Limited and Summer Extended DR. (In particular, the latter price would be the higher of: (a) the price set by the intersection of the supply curve defined by the Summer Extended DR and Annual Resources offers with the MESR Requirement and (b) the price set by the intersection of the overall resource supply curve (from the Annual Resources, Summer Extended DR, and Limited DR offers) and the RPM demand curve.)

b. The upper limit on capacity additions was increased to 10% per year, simulating a situation in which investment could react more quickly to perceived shortages.

c. The risk aversion coefficient was reduced to 0.6 to simulate lower risk aversion.

d. Relative weights (used in the revenue forecasting method) on revenues in the five years previous to the auction were made equal, resulting in more stable forecasts of revenues than forecasts that weight more recent years more heavily.

e. Load Forecast Uncertainty was eliminated, in order to simulate the situation in which investors ignore year-to-year weather-based variations in E&AS

revenues when evaluating investments, and are only concerned with longer-run demand growth uncertainty.

33. The base case results and the sensitivity analysis results are shown Table 2. It can be observed that the changes in various general assumptions did change the quantitative level of performance (capacity adequacy, generator revenues and profits, and consumer costs) of RPM. However, the sloped demand curve still robustly outperforms the vertical demand curve in all cases on both reliability indices, as well as consumer costs. The precise degree to which the sloped curve is superior depends on the assumptions, as would be expected, but the vertical curve is never better. In particular:

a. Increasing the new capacity offers to \$50,000/MW-year and \$100,000/MW-year yields more stable prices for both curves. This is because the capacity price no longer ranges between \$0 and the highest price (\$180,964/MW-year), but over a narrower range. This stabilization of price is consistent with the results of the Brattle study[2] that evaluated the actual offer curves submitted to the RPM Base Residual Auctions for given actual supply curves offered in eight BRAs (2007/08 through 2014/15); the sloped RPM demand curve resulted in more stable prices than what a vertical curve would have yielded, although the fact that non-zero offers are made by capacity results in less variation than anticipated by my model when zero offers are assumed.

   The impact of the higher capacity offer prices in my model, and the resulting increase in capacity price stability, is to improve the performance of the vertical curve. However, my conclusion remains (as in the sensitivity analyses in my 2005 affidavit as well) that the performance of the vertical curve (in terms of probability of meeting target, average reserve, and consumer costs) remains less desirable than the sloped curve, although the differences between the two curves narrows.

   In the context of the interpretation of the non-zero capacity offers representing Demand Resource offers for Extended Summer and Limited DR providing a price floor, this mirrors the manner in which Demand Resource offers are clearing beyond the MAR and on either the MESR or on the sloped demand curve. As my simulation results show, the current construct still results in a degradation of resource adequacy versus a sloped curve for Annual Resources.

b. Increasing the upper limit on capacity additions to 10% per year, which is well in excess of any amount of generation investment experienced in PJM, improved the performance of the vertical curve, but the sloped curve still results in better resource adequacy.

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[2] Johannes P. Pfeifenberger, Samuel A. Newell, Kathleen Spees, & Attila Hajos, Second Performance Assessment of PJM's Reliability Pricing Model, The Brattle Group, Inc. 106-109 (Aug. 26, 2011), www.brattle.com/system/publications/pdfs/000/004/833/original/Second_Performance_Assessment_of_PJM%27s_Reliability_Pricing_Model_Pfeifenberger_et_al_Aug_26_2011.pdf?1378772133.

c. Lowering the risk aversion coefficient enhances the performance of the vertical curve because the high variability in gross margins becomes less of deterrent to investment, but the sloped curve still yields better resource adequacy. I have also confirmed the theoretical expectation that if risk aversion is entirely eliminated (by using a coefficient slightly above 0.5) then the performance of the two curves is the same, because variability of gross margins becomes irrelevant to investment decisions.

d. Altering the relative weights on recent gross margins deteriorates the performance of both curves by roughly equal amounts. This is because revenues from the more distant past are less relevant than more recent experience when forecasting future revenues.

e. Eliminating consideration of Load Forecast Uncertainty had little effect on the results.

Table 2 – Base Cases and Sensitivity Analysis Results ("s.d." = Standard Deviation; Italicized Text is Sloped Curve Results)

Base Case and Sensitivity Analysis	Reserve Indices		CT Generator Profit, $/Installed MW/day (s.d.)	Components of CT Revenue		Consumer Payments for E/AS Gross Margin + RPM, $/MWh (s.d.)
	% Years Meet or Exceed MAR Require-ment for Annual Capacity	Average % Reserve in excess of MAR Require-ment for Annual Capacity (s.d.)		Energy / AS Gross Margin, $/Installed MW/day (s.d.)	RPM Payments $/Installed, MW/day (s.d.)	
Vertical Annual Curve (Base Case)	42	-0.62 (2.43)	64 (268)	96 (137)	350 (202)	30 (19)
Sloped Curve (Base Case)	*96*	*1.24 (0.65)*	*14 (59)*	*57 (47)*	*339 (29)*	*27 (4)*
Vertical Curve ($50K/MW/yr bid by new capacity)	69	0.21 (1.12)	133 (273)	71 (84)	443 (245)	35 (19)
Vertical Curve ($100K/MW/yr bid by new capacity)	80	0.44 (1.14)	94 (235)	69 (84)	407 (205)	32 (17)
Sloped Curve ($100K/MW/yr bid by new capacity)	*95*	*1.24 (0.69)*	*14 (61)*	*57 (48)*	*339 (31)*	*27 (4)*
Vertical Curve (10% CT capacity addition upper bound)	46	-0.27 (3.01)	32 (294)	98 (150)	316 (217)	27 (21)
Sloped Curve (10% CT capacity addition upper bound)	*98*	*1.24 (0.54)*	*12 (54)*	*56 (45)*	*338 (24)*	*27 (3)*
Vertical Curve (Less Risk Averse: 0.6 Coefficient)	58	0.11 (1.51)	34 (237)	73 (89)	342 (206)	28 (17)
Sloped Curve (Less Risk Averse: 0.6 Coefficient)	*93*	*1.25 (0.79)*	*13 (65)*	*57 (48)*	*338 (36)*	*27 (4)*
Vertical Curve (Equal forecast weights)	40	-1.12 (3.07)	91 (299)	118 (181)	355 (200)	32 (21)
Sloped Curve (Equal forecast weights)	*67*	*0.79 (2.09)*	*30 (140)*	*68 (81)*	*343 (90)*	*28 (9)*
Vertical Curve (No load growth uncertainty)	39	-0.60 (2.41)	50 (256)	88 (108)	345 (206)	29 (18)
Sloped Curve (No load growth uncertainty)	*100*	*1.31 (0.20)*	*9 (37)*	*54 (36)*	*337 (9)*	*26 (2)*

34. This concludes my affidavit.

Dated November 26, 2013