UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket No. ER19-105-000
	)	

PROTEST OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[2] submits this protest to the filing submitted by PJM on October 12, 2018 ("October 12th Filing"). Every four years, PJM is required to perform, through a stakeholder process, "a review of the shape of the Variable Resource Requirement [VRR] Curve … based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis."[3] Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape." Unlike most other filings that require supermajority stakeholder support, quadrennial review filings are not part of Schedule 1 to the OA and are not developed pursuant to a tariff defined process that requires stakeholder approval. Accordingly, the October 12th Filing should be evaluated as a PJM proposal only, and not as though it were representative of a stakeholder consensus.

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1 18 CFR § 385.211 (2018).

2 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

3 OATT Attachment DD § 5.10(a)(iii).

The October 12th Filing contains is deficient for the reasons addressed below and should not be approved.

I. BACKGROUND

The gross cost of new entry (Gross CONE) is the total gross cost of building a new reference unit. The net cost of new entry (Net CONE) is the Gross CONE minus net energy and ancillary services revenues. Net CONE is the revenue that a resource would have to receive in the capacity market in order to achieve its target rate of return. The calculation of the cost of new entry (CONE), both Gross CONE and Net CONE, affects the PJM Capacity Market in two important ways. The CONE affects the capacity market demand curve, or Variable Resource Requirement (VRR) Curve. Depending on whether Gross CONE is greater than 1.5 * Net CONE, the higher value defines the maximum price on the VRR Curve. Net CONE determines the price at other key points on the VRR Curve. Net CONE defines the offer cap in the capacity market under certain circumstances, Net CONE * B, where B is the balancing ratio.[4]

The Gross CONE values are based on the total costs of putting the defined reference unit in service. The Gross CONE values are expressed as the 20 year nominal levelized cost of the unit. The costs of the actual equipment and construction are combined with financial assumptions including the cost of capital, depreciation rates, and tax treatment to calculate the 20 year levelized cost. If the unit owner recovers the 20 year levelized cost in each of the 20 years, the owner will cover all its costs including the rate of return embedded in the cost of capital. In this case the reference unit used by PJM and the Market Monitor is a single 7HA.02 combustion turbine (CT).[5]

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4 *See* OATT Attachment DD § 6.4(a).

5 The IMM retained Pasteris Energy, Inc. to develop the Gross CONE values. Stantec Consulting Services Inc., a power plant design and engineering firm with CT and CC plant design experience was contracted by Pasteris Energy to determine the plant proper capital cost estimate for the

There are issues with PJM's calculation of Gross CONE, including the cost of the gas pipeline lateral necessary to deliver gas to the unit and the level of contingency built into the costs of the EPC (engineering, procurement and construction) contractor.

Net CONE is Gross CONE less the expected net energy and ancillary services revenues. Net CONE is the revenue that, with the net revenue from energy markets and ancillary services, would cover total Gross CONE. If the unit owner recovered the Net CONE from the capacity market and the net revenues from the energy markets and ancillary services, the owner will cover all its costs including the rate of return embedded in the cost of capital.

There are issues with PJM's calculation of net revenue, including how the unit is dispatched, and the short run marginal costs of the unit which define the competitive offer and therefore the cost at which the unit will be dispatched, including the cost of gas.

PJM has filed in Docket EL19-8 to include major maintenance costs in energy offers.[6] Contrary to PJM's assertions, there is no reason for the Commission to address that issue here. If the Commission should decide to include major maintenance costs in energy offers in Docket EL19-8, the Net CONE values can be recalculated and refiled. The PJM Market Rules prohibit the inclusion of major maintenance in energy offers. The Commission should decide the appropriate approach to calculating Net CONE based on the current rules and not based on a controversial proposal that PJM has made in a separate 206 filing that was opposed by PJM members in repeated votes.[7]

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reference unit. Stantec relies on data from the OEM and from recent market transactions. The IMM has relied on Pasteris Energy and Stantec since 2008 to develop Gross CONE values for a range of plant types that are published in the State of the Market Report.

6 *See* October 12th Filing at 1. n.2, 19–20.

7 *See* "Item 01 – Draft Minutes – MRC – 7.26.2018," Markets and Reliability Committee (August 23, 2018) <https://www.pjm.com/-/media/committees-groups/committees/mrc/20180823/20180823-item-01-draft-minutes-mrc-20180726.ashx>; "Consent Agenda Item A – Draft Minutes – MC – 9.27.2018," Members Committee (October 22, 2018) <https://pjm.com/-/media/committees-

II. COMMENTS

A. Reference Resource

The Market Monitor agrees with PJM that the reference resource should be a single GE H.02 CT.

The Market Monitor believes that a careful reevaluation of the complete basis for the definition of the reference unit for the next Quadrennial Review would be useful. While a baseload combined cycle is not the correct reference unit, a natural gas fired internal combustion engine (diesel) plant may be more representative of an actual peaking plant at that time.

B. Gross CONE

Gross CONE is the total cost of the reference unit on a 20 year levelized basis.

1. Pipeline Interconnection Costs

The gas interconnection costs PJM used in developing Gross CONE are overstated by $11.6 million because PJM uses a pipeline that is sized for two units rather than for the reference unit and, for the same reason, PJM uses a larger metering station than necessary with a higher cost. The Market Monitor estimates that a new entrant CT will have pipeline costs of $13.3 million and a metering station cost of $1.5 million. This oversight is illustrated by the fact that PJM implausibly estimates pipeline costs of $23.0 million and a metering station cost of $3.4 million for both the reference CT unit and the reference CC unit even though the reference CC unit has twice the capacity of the reference CT unit.[8] The costs are

groups/committees/mc/20181025/20181025-consent-agenda-item-a-draft-20180927-mc-meeting-minutes.ashx> .

8 PJM includes $29.1 million in total pipeline costs including the metering station. This is the $26.4 million escalated to 2022 plus an additional escalation rate for equipment. See the Brattle Group Report which is part of PJM's October 12th Filing "PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date," Appendix B, Section C, pg 61.

the same because PJM is using "representative gas pipeline lateral projects" for both reference units.[9] PJM converts the costs of these projects to cost per mile, calculates the simple average of the these costs and uses the result to estimate the cost for the five mile lateral. However, the cost is overstated. The actual gas pipeline lateral projects that PJM considers representative have more than twice the capacity needed by the reference CT unit because the projects all have multiple CT units and all use 16 inch diameter or greater pipelines, with an average diameter of more than 20 inches. Both the Market Monitor and PJM assume a five mile interconnection. A 12 inch pipeline with a flow rate of 80 million SCFD would be appropriate for a single 7HA.02 CT, which is the reference unit used by PJM and the Market Monitor. A 16 inch pipeline with a flow rate of 160 million SCFD would be appropriate for two 7HA.02 CT units.

PJM estimates pipeline costs of $23.0 million, which, over a five mile lateral project, implies a $4.6 million cost per mile. Using INGAA estimates of 2018 costs of $203,770 per inch-mile, PJM has an implied pipeline diameter of 22.6 inches. [10] Using INGAA estimates of 2022 costs of $226,360 per inch-mile, PJM has an implied pipeline diameter of 20.3 inches.

Using the cost per inch-mile (2016$) from the INGAA's North America Midstream Infrastructure through 2035 report, the gas interconnection cost of a five mile 12 inch pipeline is $13.3 million, only about 58 percent of PJM's proposed $23.0 million, as shown in Table 1. [11]

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9 See the Brattle Group Report which is part of PJM's October 12th Filing, "PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date," Appendix B, Section C, Table 25: Gas Interconnection Costs, and Section IV, Table 9 and Table 10 (April 19, 2018).

10 Pipeline costs from: The INGAA Foundation, Inc. (ICF, June 18, 2018). "North America Midstream Infrastructure through 2035," <https://www.ingaa.org/File.aspx?id=34658> .

11 *Id.*

Table 1 Comparison of gas interconnection costs[12]

EMAAC Gas Interconnect	
IMM estimate	$14.8 million = $13.3 million pipeline + $1.5 million station
PJM estimate	$26.4 million = $23.0 million pipeline + $3.4 million station

INGAA Exhibit 6: Pennsylvania					
Year	$/Inch-Mile (2016$)	Line Size (Inches)	$/Mile	Miles	Cost ($)
2018	$203,770	12.0	$2,445,240	5.0	$12.2 million
2022	$226,360	12.0	$2,716,320	5.0	$13.6 million

2. EPC Contingency and Fees

The standard EPC contract includes a contingency allowance and fees. The EPC contingency and fees that PJM includes in Gross CONE are overstated by $4 million. The Market Monitor includes EPC contingency and fees of $36.5 million. PJM allows for EPC contingency and fees of $40.6 million.

The PJM contingency costs are too high because, although the Market Monitor and PJM use the same contingency rate and the same profit rate, PJM applies the contingency rate to both the profit and to PJM's initial overstated state taxes. Neither is correct and the result is an overstatement of contingency costs. It is not appropriate nor standard business practice to charge a contingency on profits. Although PJM adjusted its state tax calculation, PJM did not correspondingly reduce contingency costs.

C. Escalation of Gross CONE

CONE values are determined through first triennial and now quadrennial CONE studies with escalation rates applied in the intervening years. Instead of using escalation rates in the intervening years, the Market Monitor recommends that an updated study of the cost of the reference unit be conducted each year to determine the Gross CONE value. The differences between Gross CONE from 2017/2018 to 2018/2019 and from 2021/2022 to 2022/2023 show that when Gross CONE values were subject to a review and then reset to

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12 Market Monitor estimate provided by Pasteris Energy, Inc.

reflect current information, Gross CONE values have generally decreased, not increased, as shown in Table 2.[13] The Gross CONE decreased in both cases as a result of being reset based on the Triennial/Quadrennial Review process. The actual cost data showed that costs were lower than implied by the mechanical annual application of an escalation rate that has no direct relevance to the costs of CTs. For example, the application of the escalation rates would have resulted in a Gross CONE that was $13,075 per MW-year, or 10.4 percent, higher for the 2022/23 auction than PJM's own calculation of Gross CONE in this current review.

The Market Monitor has calculated the 20 year levelized fixed cost for a new entrant CT since 2008 (Table 3).[14] Although this CT is not exactly the same as the reference unit used for the calculation of Gross CONE, the gross cost of new CTs fluctuated year to year and declined significantly over the period as a result of technology advancements and improvements that resulted from competition in the market for CTs. Use of a simple general escalation factor that is not based on the CT technology will generally overstate Gross CONE. The Gross CONE study should be updated annually during the period between Quadrennial Reviews based on the same technology and based on the baseline assumptions. This could be done easily and efficiently given that it requires only updated gross CONE costs rather than the full Quadrennial Review process.

PJM proposes to revise the Tariff, Attachment DD, section 5.10(a)(iv)(B) to apply a 1.022 escalation factor to CONE each year to account for the declining tax advantages as bonus depreciation phases out. This would have a multiplicative impact when used with the base escalator. Building in an automatic escalator to account for one element of cost

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13 Planning Period Parameters data for the relevant auctions are located at <https://www.pjm.com/markets-and-operations/rpm.aspx>. The one exception was the reset values for 2016/2017 which were higher than prior year.

14 2017 State of the Market Report for PJM, Vol. 2, Section 7: Net Revenues, Table 7-7

which may or may not actually occur does not make sense because it would ignore the factors tending to decrease the Gross CONE. Tax laws changes need to be considered as do other factors affecting fixed costs. The Market Monitor's proposed annual update to the Gross CONE study would address this issue also.

Table 2 Gross CONE values and implied escalation factors[15] [16]

	PJM Gross CONE ($ per MW-year ICAP)					Implied Escalation Factor				
Base Residual Auction	CONE 1	CONE 2	CONE 3	CONE 4	RTO	CONE 1	CONE 2	CONE 3	CONE 4	RTO
2012/2013	$122,040	$112,868	$115,479	$112,868	$112,868	-	-	-	-	-
2013/2014	$132,169	$122,236	$125,410	$122,236	$122,236	1.0830	1.0830	1.0860	1.0830	1.0830
2014/2015	$138,646	$128,226	$131,681	$128,226	$128,226	1.0490	1.0490	1.0500	1.0490	1.0490
2015/2016	$141,973	$131,303	$134,314	$131,303	$131,303	1.0240	1.0240	1.0200	1.0240	1.0240
2016/2017	$152,460	$142,223	$139,485	$146,471	$139,392	1.0739	1.0832	1.0385	1.1155	1.0616
2017/2018	$156,881	$146,348	$143,670	$150,718	$143,434	1.0290	1.0290	1.0300	1.0290	1.0290
2018/2019	$132,200	$130,300	$128,900	$130,300	$130,425	0.8427	0.8903	0.8972	0.8645	0.9093
2019/2020	$133,332	$134,299	$132,665	$134,311	$133,652	1.0086	1.0307	1.0292	1.0308	1.0247
2020/2021	$134,310	$136,733	$133,413	$133,465	$134,480	1.0073	1.0181	1.0056	0.9937	1.0062
2021/2022	$133,144	$140,953	$133,016	$134,124	$135,309	0.9913	1.0309	0.9970	1.0049	1.0062
2022/2023 (Proposed)	$126,700	$128,200	$124,500	$124,700	$126,025	0.9516	0.9095	0.9360	0.9297	0.9314
2022/2023 (Escalated from 2021/2022)	$136,900	$144,900	$136,700	$137,900	$139,100	1.0282	1.0280	1.0277	1.0282	1.0280
Proposed 2022/2023 - Escalated 2022/2023	($10,200)	($16,700)	($12,200)	($13,200)	($13,075)	-	-	-	-	-

Table 3 20-year levelized fixed cost for a new entrant 2 CT project[17]

	20-Year Levelized Total Cost	Percent Change
2008	$127,795	-
2009	$128,705	0.71%
2010	$131,044	1.82%
2011	$110,589	(15.61%)
2012	$113,027	2.20%
2013	$109,731	(2.92%)
2014	$108,613	(1.02%)
2015	$111,639	2.79%
2016	$113,821	1.95%
2017	$95,264	(16.30%)

D. Net Revenue

The net energy and ancillary services revenue is an estimate of what net revenues will be during the relevant delivery year, three years in the future. The estimate is affected

15 Planning Period Parameters data for the relevant base residual auctions are located at <https://www.pjm.com/markets-and-operations/rpm.aspx>.

16 PJM Gross CONE values were reset for the 2012/2013, 2016/2017, 2018/2019, and 2022/2023 auctions. The 2016/2017 Gross CONE values were escalated from the 2015/2016 settlement values and were not escalated from the 2015/2016 BRA Gross CONE values. FERC accepted the proposed settlement on January 31, 2013 effective the earlier of June 30, 2012. 142 FERC ¶ 61,079.

17 2017 State of the Market Report for PJM, Vol. 2, Section 7: Net Revenues, Table 7-7

by a number of assumptions including how the unit is dispatched and what the unit's marginal costs are including the cost of gas.

1. Dispatch

The Market Monitor recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry ("CONE") VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[18]

PJM's dispatch method does not correctly reflect the way in which the reference unit would actually be dispatched. PJM's dispatch method results in lower energy net revenues and a higher Net CONE than if the resource were optimally dispatched over all hours, subject to the unit's actual operating parameters. PJM dispatches the unit only during peak hours and only in predefined blocks of four hours, which means that the new entrant CT is not permitted to run overnight or to run for less than four hours or for periods that are profitable because they overlap the two predefined four hour blocks. Even if there are two consecutive highly profitable hours during the peak hours of the day, one at the end of a predefined block and one at the beginning of a predefined block, PJM's method will not dispatch the unit because those hours are located in two separate predefined blocks. PJM's method is not optimal and understates net revenues. Under the Market Monitor's optimal dispatch, the unit would be dispatched for the two profitable hours. If, in a predefined four hour block, there are two consecutive highly profitable hours followed by two consecutive nonprofitable hours, PJM's method will continue running during the nonprofitable hours. PJM's method is not optimal and would understate net revenues. Under the Market Monitor's optimal dispatch, the unit would be dispatched for the two profitable hours and turned off for the two nonprofitable hours.

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18 *See PJM Interconnection, L.L.C.*, Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

2. Ten Percent Adder

PJM's use of a 10 percent adder to costs is inappropriate when calculating net revenue for the reference unit. Including a 10 percent adder to costs results in lower energy net revenues and a higher Net CONE. The 10 percent adder is not a cost and is not appropriately included in costs when calculating net revenues. The decision to operate a unit by a profit maximizing generator in a competitive market will be based only on short run marginal costs. The 10 percent adder is not a short run marginal cost. The 10 percent adder was originally included in cost-based offers as a proxy for the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions.[19] The owners of coal units and many gas and oil fired units, facing competition, typically exclude the additional 10 percent from their actual offers.[20] The introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly incorporate the impact of ambient temperature changes in fuel consumption in offers. Many units in the PJM market were offered at a price that is less than their cost-based offer, which also supports the fact that competing units offering at short run marginal costs exclude the 10 percent adder. In 2017, 41 percent of coal generators, 28 percent of gas generators and 53 percent of oil generators offered their entire economic operating range at a price that is less than their cost-based offer.[21]

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19 2015 State of the Market Report for PJM, Vol. 2, Section 3: Energy Market at 118. "All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs."

20 See 2017 State of the Market Report for PJM, Vol. 2, Section 3: Energy Market at 138

21 Ibid at 139.

3. VOM

a. Major Maintenance Costs

PJM's preferred approach to major maintenance costs is inconsistent with the PJM Market Rules. PJM's preferred approach is to include major maintenance costs in the energy offer of the reference unit and not in the Gross CONE.[22] Major maintenance costs are not short run marginal costs and should not be included in energy offers. In fact, as indicated in Docket No. ER19-210, PJM's proposal is to permit generators to choose whether to include major maintenance in the energy offer or the capacity offer.[23] It is not possible to calculate Net CONE correctly and unambiguously for the capacity market without having a clear rule requiring the avoidable costs associated with major maintenance to be collected either in the capacity market or the energy market.

PJM's proposed inclusion of major maintenance in energy offers and not in Gross CONE would reduce Net CONE. The results of the Market Monitor's analysis are shown in Table 4. The analysis holds the dispatch method and the other elements of the calculation of Gross CONE constant and varies only the treatment of major maintenance and the amount of VOM in short run marginal cost. The right side of Table 4 shows Gross and Net CONE values using PJM's proposed Gross CONE with major maintenance excluded from Gross CONE and included in the energy offers. The energy and ancillary services revenues are calculated using PJM's \$23,000 cost per unit start, \$1.10/MWh VOM, major maintenance included in energy offers and the Market Monitor's dispatch method and choice of gas pipelines. The left side of Table 4 shows Gross CONE and Net CONE values with major maintenance based on the number of starts in the updated dispatch scenario included in Gross CONE. The energy and ancillary services revenues are calculated using the Market

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22 October 12th Filing at Table 1

23 *PJM Interconnection, L.L.C.*, Docket No. ER19-210-000 "Maintenance Adder Revisions to the PJM Open Access Transmission Tariff," (October 29, 2018).

Monitor's $0.38/MWh VOM, dispatch method, and choice of gas pipelines, with major maintenance not included in energy offers. While Gross CONE is lower when major maintenance is removed from Gross CONE, net revenues are also lower as a result of increased energy offers and higher start costs. The net result is that Net CONE is lower as a result of PJM's proposed mischaracterization of major maintenance.

Table 4 Comparison of Net CONE with major maintenance in Gross CONE and major maintenance in energy offers

	$/MW-Day									
	PJM Gross CONE w/ Major Maintenance in Gross CONE ($0.38/MWh VOM)					PJM Gross CONE w/ Major Maintenance in energy offers ($23,000/start and $1.10/MWh VOM)				
	CONE 1	CONE 2	CONE 3	CONE 4	RTO	CONE 1	CONE 2	CONE 3	CONE 4	RTO
Gross CONE (ICAP)	$347.12	$351.23	$341.10	$341.92	$345.34	$295.89	$300.55	$289.04	$289.04	$293.63
E&AS Revenues	$174.63	$235.23	$180.23	$279.11	$198.88	$140.08	$190.75	$144.33	$252.94	$163.99
Net CONE (ICAP)	$172.50	$116.01	$160.86	$62.80	$146.46	$155.81	$109.80	$144.71	$36.10	$129.64

Major maintenance costs are not short run marginal costs and should not be included in the short run marginal cost of the reference unit for defining dispatch. Major maintenance costs for CTs are not includable in cost-based energy offers under the current PJM Market Rules. Major maintenance costs are incurred to maintain the availability of the unit. The Market Monitor recommends including major maintenance costs in the Gross CONE and using short run marginal cost as the competitive energy offer and the rate at which the unit would be dispatched.

PJM made mistakes in its calculation of net revenues when major maintenance is included in energy offers. The Brattle Group concluded that major maintenance costs are all start costs. But to include the major maintenance cost in short run marginal costs, PJM converted the maintenance cost per start provided by the Brattle Group to dollars per MWh. PJM's proposed energy offers include $5.83 per MWh cost, which is the $23,464 per start cost converted to a VOM cost. In order to convert the start cost to a dollar per MWh rate, PJM assumed an average 11.1 hours per start. While PJM did not disclose how that average run hours per start were developed, it is incorrect to simply assume a number of hours per start. The number of run hours is dependent on the level of the cost in the energy offer and the LMP. With a $5.83 per MWh cost, the average run hours per start may not equal 11.1. The problem, as defined by PJM, is iterative and it does not appear that PJM's approach incorporated that fact. The Market Monitor's approach includes major maintenance in Gross CONE, which is consistent with the dispatch of the unit. When dispatched optimally and not required to shut down each night as the PJM approach requires, the average run hours per start were 135 hours.

b. Short Run Marginal Cost

PJM also calculated net CONE including major maintenance in Gross CONE and not in the dispatch rate. PJM filed the alternative Gross CONE value including major maintenance and an energy offer excluding major maintenance costs.[24] PJM used a $1.10 per MWh VOM cost excluding major maintenance. The Market Monitor used a VOM of $0.38 per MWh. The Market Monitor's calculation is based on a detailed review of the costs incurred by the reference resource. The Brattle Report correctly, but incompletely describes the short run marginal cost of VOM as for consumables, waste disposal and "other VOM."[25] There is no support for PJM's number in the Brattle Report. The value developed by the Market Monitor includes the cost of ammonia used in the SCR, water use, lubricants and other consumables. The value estimated by Brattle and used by PJM appears to be too high based on the correctly identified components of SRMC and the costs of those components. The value is also inconsistent between the two technologies, the VOM of CC reference unit developed by Brattle was $0.67/MWh, 39 percent lower than the VOM of the Brattle CT reference unit.[26] This is inconsistent with the SRMC of each technology since CC incur

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24 October 12th Filing at Table 2

25 See the Brattle Group Memorandum which is part of PJM's October 12th Filing, "Impact of Sales Tax Exemption with Updated ATWACC," Table 3: O&M Costs for CT Reference Resource (September 26, 2018).

26 See the Brattle Group Memorandum which is part of PJM's October 12th Filing, "Impact of Sales Tax Exemption with Updated ATWACC," Table 4: O&M Costs for CC Reference Resource (September 26, 2018).

substantially more water expenses compared to a CT. This also suggests that the Brattle VOM for the CT is overstated.

The Market Monitor recommends that the Commission require PJM to use the Net CONE calculation with major maintenance as part of Gross CONE, based on current PJM Market Rules, and that PJM either support its value of $1.10 per MWh or use the Market Monitor's value of $0.38 per MWh.

4. Gas Costs

Most of the marginal cost of operating the reference unit is the cost of gas. The cost of gas is based on gas cost data by pricing hub.[27] The Market Monitor and PJM disagree over the new entrant gas pricing hub used for three zones: AEP, PPL, and PSEG (Table 5). The Market Monitor defined a set of criteria for selecting the relevant gas pricing hub and applied it systematically to determine the gas pricing hubs. The Market Monitor selected the gas pricing hubs based on the hubs accessible to existing units in each PJM zone where that access is available to new entrants and where that access is not based on firm transportation or location behind a local gas distribution company (LDC).[28] The Market Monitor selected the lowest priced hubs between 2015 and 2017 from the defined accessible hubs within each zone. PJM did not follow the same criteria as the Market Monitor and neither PJM nor Brattle defined a set of criteria and applied it. Brattle provided ad hoc reasons for changing the hubs from what PJM used in prior Triennial Review. In the case of AEP, Brattle did not recommend a change to the hub. In the case of PPL, the Brattle recommendation was not to use the lowest cost production gas hub. In the case of PSEG, the assumption made by Brattle that PSEG Zone only has access to Transco 6 NY and 6 Non-NY is incorrect. The PSEG Zone does have access to Tetco M3.

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[27] Gas prices obtained from Platts.

[28] Gross CONE calculations do not include the cost of firm pipeline transportation in PJM's approach or in the Market Monitor's approach because the reference has dual fuel capability.

Table 5 Comparison of gas pricing hubs used

Zone	IMM	PJM
AEP	Texas Gas Zone 1	Columbia Gas Appalachia
PPL	TGP Zone 4 300L	Texas Eastern Zone M-3
PSEG	Texas Eastern Zone M-3	Transco Zone 6 NY

The choice of gas pricing hubs significantly affects net revenues and Net CONE (Table 6).

Table 6 Impact of gas pipelines used

	$/MW-Day									
	Net CONE Calculated Using IMM E&AS Revenues					Net CONE Calculated Using IMM Method on PJM Pipelines				
	CONE 1	CONE 2	CONE 3	CONE 4	RTO	CONE 1	CONE 2	CONE 3	CONE 4	RTO
PJM Gross CONE (ICAP)	$315.92	$308.03	$301.13	$274.92	$302.33	$315.92	$308.03	$301.13	$274.92	$302.33
E&AS Revenues	$174.63	$235.23	$180.23	$279.11	$198.88	$160.66	$235.23	$180.91	$252.54	$191.01
Net CONE (ICAP)	$141.30	$72.81	$120.90	($4.19)	$103.45	$155.27	$72.81	$120.23	$22.39	$111.32
Net CONE (UCAP)	$150.14	$77.37	$128.47	($4.45)	$109.92	$164.98	$77.37	$127.75	$23.79	$118.29

5. Start Costs

The level of start fuel assumed by PJM for the reference resource is overstated. This increases the start cost. The Market Monitor's start costs are based on a careful technical analysis of the fuel that would be used in starting the reference unit and achieving full load based on the OEM starting and loading curves.

6. Overall Impact

Each of the differences between the PJM position and the IMM position has the same directional impact on the Net CONE calculation. The Market Monitor has a lower Gross CONE than PJM (pipeline costs, contingency fees). The Market Monitor also has higher net energy revenues than PJM (dispatch method, no 10 percent adder, lower VOM, lower gas costs, lower start costs). The combined effect is that the Market Monitor's calculation of Net CONE is lower than the PJM calculation.

Table 7 Comparison of Gross and Net CONE ($/MW-Day)

	$/MW-Day									
	IMM					PJM				
	CONE 1	CONE 2	CONE 3	CONE 4	RTO	CONE 1	CONE 2	CONE 3	CONE 4	RTO
Gross CONE (ICAP)	$315.92	$308.03	$301.13	$274.92	$302.33	$347.12	$351.23	$341.10	$341.92	$345.34
E&AS Revenues	$174.63	$235.23	$180.23	$279.11	$198.88	$94.45	$162.91	$110.23	$157.19	$108.73
Net CONE (ICAP)	$141.30	$72.81	$120.90	($4.19)	$103.45	$252.68	$188.32	$230.87	$184.73	$236.61

E. Forward Looking Net Revenue

The net revenue offset should be forward looking rather than relying on historical revenue. Historical revenue is always wrong. Instead of using historical revenue from a dispatch based on specific power and gas prices that are unlikely to be repeated, energy revenues from a dispatch based on forward curves for power and gas are the best estimate of expected net revenue. Using forward curves is consistent with project valuation methods used in practice by market participants. Even though there will be uncertainty in the forward curves for energy and gas on which forward looking net revenue offsets would be based, real developers of real power plants look forward and not backwards when evaluating a decision to invest in a new power plant. For example, the historical data include the impact of very low gas prices in some areas and the lowest energy prices in PJM history in 2016 and 2017. The forward curves indicate that the market does not expect these conditions to be repeated in the future. Table 8 shows the historical and forward spark spreads by zone. The spark spread is defined as the difference between the LMP received for selling power and the cost of gas used to generate power, converted to a cost per MWh. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of net revenue and profitability. The results show significant differences between the historical and forward spark spreads by zone. The differences are even more significant when evaluated year by year.

Table 8 Average Monthly Spark Spread[29]

	Average Monthly Spark Spread ($/MWh)							3-Year Average		Percent
Zone	2015	2016	2017	2018	2019	2020	2021	2015-2017	2019-2021	Change
AECO	$1.77	$5.42	$1.78	-	$1.97	$2.91	$3.99	$2.99	$2.96	(1.0%)
AEP	$8.85	$6.20	$3.26	-	$11.83	$9.68	$8.82	$6.10	$10.11	65.6%
APS	$20.34	$13.54	$9.52	-	$14.10	$12.29	$11.84	$14.47	$12.74	(11.9%)
ATSI	$6.71	$5.86	$3.58	-	$12.08	$10.51	$9.27	$5.38	$10.62	97.4%
BGE	$11.74	$17.06	$6.48	-	$7.38	$7.76	$8.55	$11.76	$7.90	(32.9%)
COMED	$1.81	$1.98	($1.06)	-	$6.03	$4.71	$3.66	$0.91	$4.80	427.5%
DAY	$6.72	$5.57	$3.34	-	$12.00	$10.46	$9.22	$5.21	$10.56	102.7%
DEOK	$5.80	$4.79	$2.70	-	$10.86	$9.49	$8.31	$4.43	$9.56	115.7%
DOM	$4.72	$7.09	$2.46	-	$3.57	$4.45	$5.72	$4.76	$4.58	(3.7%)
DPL	($2.09)	($0.14)	($3.17)	-	($2.35)	($1.83)	($0.94)	($1.80)	($1.71)	(5.1%)
DUQ	$4.90	$9.10	$3.79	-	$2.94	$3.24	$3.64	$5.93	$3.27	(44.9%)
EKPC	$6.88	$4.93	$1.78	-	$9.73	$7.76	$6.71	$4.53	$8.07	78.1%
JCPL	$1.26	$4.86	$2.36	-	$2.63	$3.49	$4.52	$2.83	$3.55	25.5%
METED	$9.54	$8.64	$6.52	-	$4.85	$5.20	$5.64	$8.23	$5.23	(36.5%)
PECO	$9.17	$8.02	$5.37	-	$3.81	$4.26	$4.76	$7.52	$4.28	(43.1%)
PENELEC	$19.03	$11.57	$8.91	-	$13.26	$11.52	$11.11	$13.17	$11.97	(9.1%)
PEPCO	$6.69	$8.98	$2.72	-	$4.04	$4.86	$6.10	$6.13	$5.00	(18.4%)
PPL	$19.81	$9.07	$8.00	-	$12.02	$10.72	$10.26	$12.29	$11.00	(10.5%)
PSEG	$11.75	$8.75	$6.52	-	$5.16	$5.46	$5.87	$9.01	$5.50	(39.0%)
RECO	$1.14	$4.81	$2.14	-	($1.90)	($1.45)	($0.65)	$2.70	($1.34)	(149.5%)

Using forward curves to calculate net revenue would also allow the net E&AS offset to adjust to any expected changes in energy prices based on market fundamentals or energy market design changes. If there are energy pricing reforms and historical revenue is used instead of forward curves, the historical net E&AS offset will not account for the energy market pricing reforms affecting future net revenues.

The Commission should direct PJM to develop a forward looking method for calculating net revenues through a stakeholder process now rather than waiting until the next Quadrennial Review.

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29 Spark spreads are for all hours. Spark spreads assume a heat rate of 9,000 Btu/kWh. Gas prices obtained from Platts. Forward prices on November 16, 2018. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and zonal prices. The basis adjustment is based on 2017 data.

F. One Percent VRR Curve Shift

The Market Monitor supports the proposal to discontinue the one percent rightward shift in the VRR Curve. Beginning with the 2018/2019 RPM Base Residual Auction, PJM has included a one percent rightward shift in the VRR Curve to mitigate certain low probability risks. The shift was recommended by the Brattle Group to lower the probability of under procuring capacity in the event of a supply or demand shock, or underestimating Net CONE.[30] PJM provided additional details regarding the shift to the Commission, basing the need for the VRR Curve shift on uncertainty of supply due to the Mercury and Air Toxic Standards (MATS), the vacating of Order No. 745, the EPA's Greenhouse Gas Rule, and advances in combined cycle generation.[31] The Commission approved the change noting "PJM appropriately accounted for this modeling inadequacy and the underlying potential for supply shifts with a more conservative VRR Curve, i.e., with a VRR Curve that will result in the procurement of additional capacity."[32]

The Market Monitor has found that the one percent shift has had a significant impact on the RPM auction results. Had the one percent rightward shift been removed from the VRR Curve for the 2021/2022 RPM Base Residual Auction and everything else remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,648,601,896, a decrease of $652,275,210, or 7.0 percent, compared to the actual results.[33]

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30 See PJM "Third Triennial Review of PJM's Variable Resource Requirement Curve," <*http://www.pjm.com/-/media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curve-report.ashx?la=en*> (May 15, 2014) at 68.

31 149 FERC ¶ 61,183 at P 25 (2014).

32 *Id*. at P 52.

33 See Scenario 4 at P. 65, "Analysis of the 2021/2022 RPM Base Residual Auction: Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> .

The rightward shift has contributed to the significant over procurement of capacity by PJM and exacerbated the impacts of PJM's systematic over forecasting of load in the capacity market.

G. Overall Impact on VRR Curve and Capacity Prices

Figure 1 shows the RTO VRR Curves proposed by the Market Monitor and PJM which both use the 2021/2022 BRA parameters except for the proposed Net CONE values. The 2021/2022 BRA RTO VRR Curve and the aggregate supply curve from the 2021/2022 BRA are also included.[34] The VRR Curves are currently defined by three inflection points. The capacity MW level for inflection point A is approximately 1.0 percent lower than the reliability requirement, and the price point for inflection point A is defined as the greater of Gross CONE and 1.5 times Net CONE.[35] [36] The capacity level for inflection point B is approximately 1.6 percent higher than the reliability requirement, and the price point for inflection point B is defined as 0.75 x Net CONE.[37] Inflection point C is defined as the point where the VRR Curve intersects the horizontal axis.[38]

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34 Due to the nested hierarchy used in the RPM auction clearing process, the IMM and PJM VRR curves illustrate the potential impacts of using a revised VRR Curve but do not represent actual equilibrium values that would have resulted if the 2021/2022 BRA had been solved with the revised VRR curves in place.

35 The reliability requirement used in defining the inflection points has been adjusted for the Fixed Resource Requirement (FRR) and the capacity levels also include EE addback adjustments.

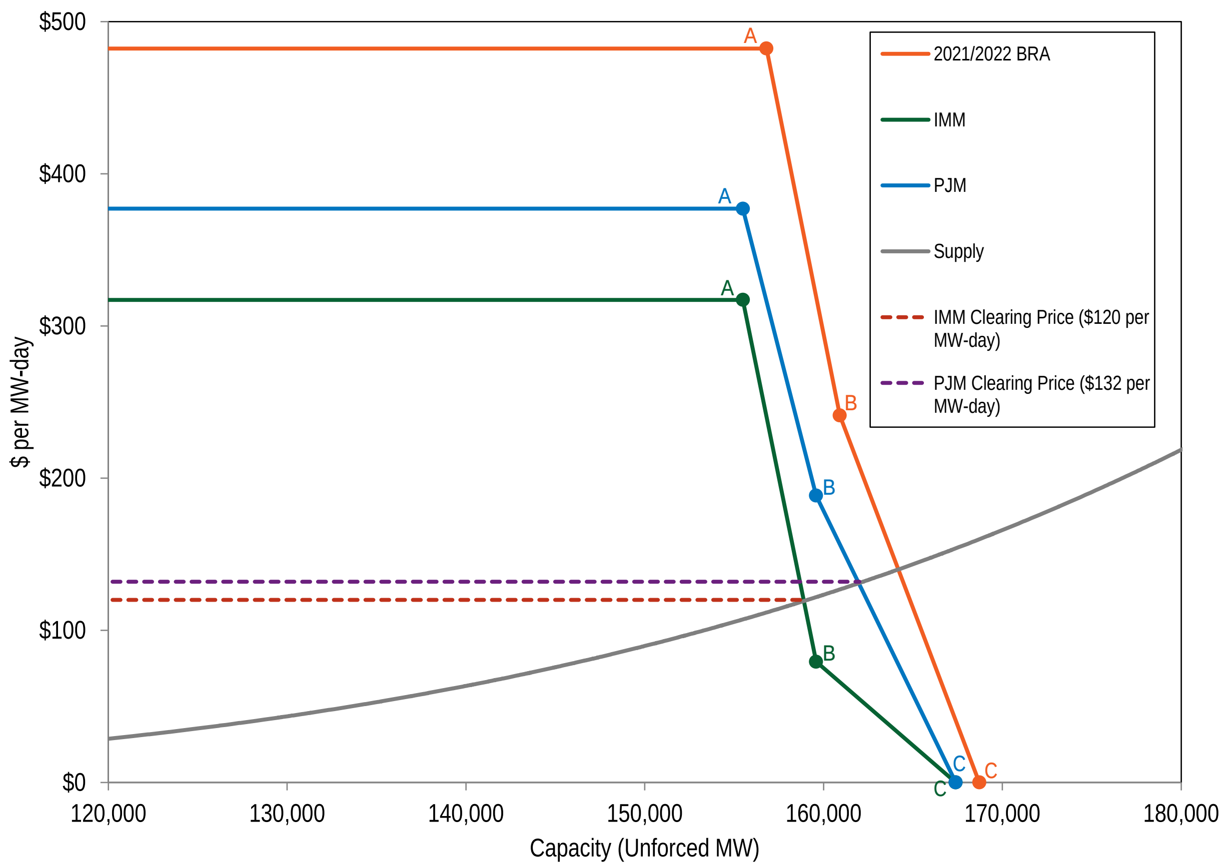
36 The capacity levels for inflection point A of the IMM and PJM VRR Curves are equal to (1+IRM-1.2%)/(1+IRM) x Reliability Requirement, which reflects the proposed discontinuance of the 1 percent rightward shift. The capacity level for inflection point A of the VRR Curve used in the 2021/2022 BRA was equal to (1+IRM-0.2%)/(1+IRM) x Reliability Requirement.

37 The capacity levels for inflection point B of the IMM and PJM VRR Curves are equal to (1+IRM+1.9%)/(1+IRM) x Reliability Requirement, which reflects the proposed discontinuance of the 1 percent rightward shift. The capacity level for inflection point B of the VRR Curve used in the 2021/2022 BRA was equal to (1+IRM+2.9%)/(1+IRM) x Reliability Requirement.

38 The capacity level for inflection point C of both the IMM and PJM VRR Curves is equal to (1+IRM+7.8%)/(1+IRM) x Reliability Requirement, which reflects the proposed discontinuance of

The price point for inflection point A of the IMM VRR curve in Figure 1 is equal to the gross CONE value of $317.15 per MW-day. The price point for inflection point A of the PJM VRR Curve in Figure 1 is equal to 1.5 x net CONE or $377.13 day MW-day. The price point for inflection point B of the IMM VRR Curve is $79.37 per MW-day and the price point for inflection point B of the PJM VRR Curve is $188.57.

Figure 1 Comparison of Market Monitor and PJM VRR Curves



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the 1 percent rightward shift. The capacity level for inflection point B of the VRR Curve used in the 2021/2022 BRA was equal to (1+IRM+8.8%)/(1+IRM) x Reliability Requirement.

III. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to this protest as it resolves the issues raised in this proceeding.

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Dated: November 19, 2018

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 19th day of November, 2018.

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