Comments to the Maryland PSC
Senate Bill 1 Co-location Study
Administrative Docket PC 61

The Independent Market Monitor for PJM

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Introduction

The Independent Market Monitor for PJM (IMM) submits these comments to the Maryland Public Service Commission (MD PSC) to assist the Public Service Commission in its evaluation of the issues related to co-located load in Maryland.

The IMM supports competitive markets in PJM. Competitive markets provide the lowest possible cost of power, but no lower. Competitive markets only work because the structure of the markets and the behavior of market participants are governed by rules.

Co-Located Load in PJM: Overview

The extremely tight capacity market conditions that resulted from the current PJM ELCC capacity market rules highlight the significance for future capacity market auctions of the ongoing efforts to place new data center loads behind nuclear power plants and potentially other thermal generators and thus remove that capacity from the capacity market. Removal of even a relatively small amount of capacity from the market would have a significant impact on capacity market prices. The gains for the specific co-located loads would come at the expense of other customers in the PJM markets. The core benefit to the specific co-located loads is avoiding the costs associated with both state and federal regulation. The co-located load would avoid paying distribution charges and transmission charges and would not be directly subject to the rate regulation of the state public utility commission or the FERC.

If this co-located load approach were extended to all the nuclear plants in PJM, the impact on the PJM grid and markets would be extreme. Power flows on the grid that was built in significant part to deliver low cost nuclear energy to load would change significantly. Energy prices would increase significantly as low cost nuclear energy is displaced by higher cost energy on the overall supply curve. Capacity prices would increase as the supply of capacity to the market is reduced. Emissions would also increase as thermal resources that are next in the supply curve are dispatched to meet load to replace the nuclear energy. Establishing this precedent would undermine PJM reliability and PJM competitive markets.

Power grids were built to permit all participants to take advantage of the diverse characteristics of loads and of generation. When a generator is on an outage, other generators are available on the grid to replace the output. The co-located model would directly remove significant capacity from the market but the co-located load would continue to rely on the grid for backup. The co-located proposals illustrate the basic fact that the co-located load cannot and will not be isolated from the grid. The co-located load model would rely on the grid for backup while pretending to be isolated from the grid.

The issue of co-located load has extremely large significance for the future of PJM markets. PJM has not explained how it plans to meet expected increases in the demand for power, given the extreme tightness of the capacity market under the current ELCC model and given ongoing generator retirements, even without removing multiple large base load units from the system. PJM's latest reliability report and PJM's RTEP do not address the potential significant changes that would result from increases in co-located load. No co-located load should be approved without such analysis and a stakeholder review process and a consideration of the facts by the Commission.

Co-Located Load: Issues and Impacts

Proposals for how to treat co-located load raise a set of significant policy issues that will be appropriately decided by the MD PSC, by other state commissions in PJM and by FERC. These issues should not be decided by PJM in private discussions about bilateral arrangements via amended Interconnection Service Agreements (ISAs.) ISAs are not private contracts beyond the purview of the regulatory process. The proposed amended Susquehanna ISA is evidence that PJM is making policy through confidential negotiations of ISAs, without public, transparent discussion of the merits and implications of that policy and without review by the regulatory authorities charged with policy making responsibility.

Contrary to assertions by some supporters of specific co-located load arrangements, it is not possible for co-located load to be off the grid. All load, including co-located load, is on the grid, affects the grid, and benefits from the grid. As a result, decisions about co-located load in PJM affect all PJM customers, in Maryland and in PJM.

It is essential that the addition of significant new loads go through the normal PJM analysis process, even if time consuming. Every new generator and every large load addition goes through this process. PJM is a complex, interactive system. There are no short cuts. The fact that PJM's analysis process is less than perfect is not a reason for some generators or load to jump the queue.

One of the issues with the amended ISA for Susquehanna, for Susquehanna directly and if that ISA were to become the template, is the definition of backup power. That definition illustrates the fact that it is not possible for the designated load to be off the grid. While nuclear capacity equal to the designated load would give up its Capacity Interconnection Rights (CIRs) and would no longer be PJM capacity, the ISA would rely on the grid for backup if the dedicated plant were on outage for any reason. The definition of backup in the amended ISA is not consistent with the assertions of supporters of that ISA that co-located load is not leaning on the grid.

The issues related to co-located load are not abstract issues in Maryland or in PJM. The PJM Capacity Market is tight and the capacity market in Maryland is even more so. In the last capacity auction, the BRA for 2025/2026, Maryland had the highest capacity prices in PJM. In the next capacity auction, Maryland faces the prospect of much higher capacity prices based on the maximum price as defined by the parameters posted by PJM for the 2026/2027 BRA. Maryland is short of capacity right now. The issue was exacerbated by the loss of Brandon Shores and Wagner power plants. As a result, Maryland cleared at the maximum capacity price in 2025/2026. The PJM defined maximum price for the 2026/2027

BRA is almost $700 per MW-day. While the outcome of the 2026/2027 BRA will depend on multiple factors, the maximum defined price creates risk for Maryland customers.

The addition of co-located load, as defined by its supporters, would mean the loss of additional capacity in Maryland with the result that Maryland would be even more short of capacity and even more at risk of persistent high capacity prices.

Analysis of Potential Impacts

The IMM did sensitivity analyses of the impacts of removing different levels of capacity in Maryland and PJM on capacity market prices in Maryland, based on the inputs for the 2025/2026 BRA, including PJM market parameters and the actual offers of capacity resources. The sensitivity analyses include removing 1,000 MW of nuclear capacity in Maryland, removing all nuclear capacity in Maryland (Calvert Cliffs), and removing 10,000 MW of nuclear capacity across all PJM nuclear plants. The results include the increase in overall payments for capacity and the impacts to payments by customers in Maryland. The IMM also estimated the impact on energy market charges to customers under these scenarios. The costs to customers of wholesale market power, holding aside transmission costs, are primarily the sum of capacity and energy costs.

Table 1 shows the impact of removing 1,000 UCAP MW of nuclear capacity in Maryland on RPM revenues for the auction. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If 1,000 UCAP MW of nuclear capacity in Maryland did not offer in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, the total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $18,331,481,992, an increase of $3,644,434,634, or 24.8 percent, compared to the actual results. From another perspective, inclusion of offers from 1,000 UCAP MW of nuclear capacity in Maryland resulted in a 19.9 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had 1,000 UCAP MW of nuclear capacity in Maryland was not offered (Scenario 1).

Table 2 shows the impact of removing all offered nuclear capacity in Maryland on RPM revenues for the auction. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If all nuclear capacity in Maryland did not offer in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, the total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $20,435,378,503, an increase of $5,748,331,145, or 39.1 percent, compared to the actual results. From another perspective, inclusion of offers from nuclear capacity in Maryland resulted in a 28.1 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had all nuclear capacity in Maryland was not offered (Scenario 2).

Table 3 shows the impact of removing 10,000 UCAP MW in total from all nuclear capacity in PJM on RPM revenues for the auction. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If 10,000 UCAP MW of nuclear capacity in PJM did not offer in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, the total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $20,864,364,456, an increase of $6,177,317,098, or 42.1 percent, compared to the actual results. From another perspective, inclusion of offers from 10,000 UCAP MW of nuclear capacity in PJM resulted in a 29.6 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had 10,000 UCAP MW of nuclear capacity in PJM was not offered (Scenario 3).

Summary Results Tables

Table 1 Scenario summary for 2025/2026 RPM Base Residual Auction: Impact on RPM revenue due to the removal of nuclear generation

			Scenario Impact		
			RPM Revenue	Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
1	Remove 1,000 UCAP MW from Maryland nuclear resources	$18,331,481,992	($3,644,434,634)	(19.9%)	24.8%
2	Remove all UCAP MW from Maryland nuclear resources	$20,435,378,503	($5,748,331,145)	(28.1%)	39.1%
3	Remove 10,000 UCAP MW in total from all nuclear resources offered in BRA	$20,864,364,456	($6,177,317,098)	(29.6%)	42.1%

Table 2 Scenario summary for 2025/2026 RPM Base Residual Auction: Impacts on RPM cleared UCAP MW due to the removal of nuclear generation

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
1	Remove 1,000 UCAP MW from Maryland nuclear resources	134,707.1	976.9	0.7%	(0.7%)
2	Remove all UCAP MW from Maryland nuclear resources	134,125.5	1,558.5	1.2%	(1.1%)
3	Remove 10,000 UCAP MW in total from all nuclear resources offered in BRA	134,707.1	976.9	0.7%	(0.7%)

Impact on Load Charges to Maryland

Table 3 shows the gross and net load charges to Maryland for the 2025/2026 BRA and for Scenario 1. The net load charges are net of the value of Capacity Transfer Rights (CTRs). The value of CTRs reflect the fact that customers pay the highest price only for local capacity and pay the lower price of imported capacity for the capacity imported from elsewhere in PJM.

Table 3 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2025/2026 RPM BRA for Maryland were $1,484,226,706. In the 2025/2026 RPM BRA, only 612.9 UCAP MW of BGE capacity resources cleared. The BGE LDA imported 6,031 UCAP MW from the rest of the SWMAAC LDA. The clearing price for the BGE LDA was $196.43 per MW-day higher than the clearing price of the rest of the SWMAAC LDA. The load in the BGE Zone received CTR credits of $357,767,342. After accounting for CTRs, the net load charges for the 2025/2026 RPM BRA for Maryland were $1,126,459,364.

If 1,000 UCAP MW of nuclear capacity in Maryland was not offered in the 2025/2026 RPM BRA and if the capacity price for Maryland were equal to the weighted average of the Maryland LDAs' clearing prices in the BRA, the load charges for Maryland would have been $1,458,070,898, an increase of $331,611,535, or 29.4 percent higher than in the 2025/2026 BRA.

Table 3 Net load charges for Maryland (Scenario 1)

Remove 1,000 UCAP MW from Maryland nuclear resources						
	BRA ($/Year)			Scenario ($/Year)		
Zone	Zonal Obligation	Value of CTR Credits	Net Zonal Obligation	Zonal Obligation	Value of CTR Credits	Net Zonal Obligation
APS	$165,790,906	$0	$165,790,906	$210,949,008	$0	$210,949,008
BGE	$1,026,536,627	$357,767,342	$668,769,284	$1,021,061,268	$172,165,652	$848,895,616
DPL	$113,156,485	$0	$113,156,485	$154,374,830	$0	$154,374,830
Pepco	$178,742,689	$0	$178,742,689	$243,851,445	$0	$243,851,445
Total Maryland	$1,484,226,706	$357,767,342	$1,126,459,364	$1,630,236,550	$172,165,652	$1,458,070,898

Table 4 shows the gross and net load charges to Maryland for the 2025/2026 BRA and for Scenario 2. The net load charges are net of CTRs.

Table 4 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2025/2026 RPM BRA for Maryland were $1,484,226,706. In the 2025/2026 RPM BRA, only 612.9 UCAP MW of BGE capacity resources cleared. The BGE LDA imported 6,031 UCAP MW form the rest of the SWMAAC LDA. The clearing price for the BGE LDA was $196.43 per MW-day higher than the clearing price of the rest of the SWMAAC LDA. The load in the BGE Zone received CTR credits of $357,767,342. After accounting for CTRs, the net load charges for the 2025/2026 RPM BRA for Maryland were $1,126,459,364.

If the entire nuclear capacity in Maryland was not offered in the 2025/2026 RPM BRA and if the capacity price for Maryland were equal to the weighted average of the Maryland LDAs' clearing prices in the BRA, the load charges for Maryland would have been $1,672,679,428, an increase of $546,220,065, or 48.5 percent higher than in the 2025/2026 BRA.

Table 4 Net load charges for Maryland (Scenario 2)

Remove all UCAP MW from Maryland nuclear resources						
	BRA ($/Year)			Scenario ($/Year)		
Zone	Zonal Obligation	Value of CTR Credits	Net Zonal Obligation	Zonal Obligation	Value of CTR Credits	Net Zonal Obligation
APS	$165,790,906	$0	$165,790,906	$237,492,327	$0	$237,492,327
BGE	$1,026,536,627	$357,767,342	$668,769,284	$1,016,750,639	$50,079,425	$966,671,214
DPL	$113,156,485	$0	$113,156,485	$181,623,024	$0	$181,623,024
Pepco	$178,742,689	$0	$178,742,689	$286,892,862	$0	$286,892,862
Total Maryland	$1,484,226,706	$357,767,342	$1,126,459,364	$1,722,758,853	$50,079,425	$1,672,679,428

Table 4 shows the gross and net load charges to Maryland for the 2025/2026 BRA and for Scenario 2. The net load charges are net of CTRs.

Table 5 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2025/2026 RPM BRA for Maryland were $1,484,226,706. In the 2025/2026 RPM BRA, only 612.9 UCAP MW of BGE capacity resources cleared. The BGE LDA imported 6,031 UCAP MW from the rest of the SWMAAC LDA. The clearing price for the BGE LDA was $196.43 per MW-day higher than the clearing price of the rest of the SWMAAC LDA. The load in the BGE Zone received CTR credits of $357,767,342. After accounting for CTRs, the net load charges for the 2025/2026 RPM BRA for Maryland were $1,126,459,364.

If 10,000 UCAP MW of nuclear capacity in PJM was not offered in the 2025/2026 RPM BRA and if the capacity price for Maryland were equal to the weighted average of the Maryland LDAs' clearing prices in the BRA, the load charges for Maryland would have been $1,652,644,171, an increase of $526,184,808, or 46.7 percent higher than in the 2025/2026 BRA.

Table 5 Net load charges for Maryland (Scenario 3)

Remove 10,000 UCAP MW in total from all nuclear resources offered in BRA						
	BRA ($/Year)			Scenario ($/Year)		
Zone	Zonal Obligation	Value of CTR Credits	Net Zonal Obligation	Zonal Obligation	Value of CTR Credits	Net Zonal Obligation
APS	$165,790,906	$0	$165,790,906	$256,229,711	$0	$256,229,711
BGE	$1,026,536,627	$357,767,342	$668,769,284	$952,988,243	$16,876,887	$936,111,356
DPL	$113,156,485	$0	$113,156,485	$181,025,619	$466,758	$180,558,861
Pepco	$178,742,689	$0	$178,742,689	$279,744,242	$0	$279,744,242
Total Maryland	$1,484,226,706	$357,767,342	$1,126,459,364	$1,669,987,816	$17,343,645	$1,652,644,171

Impact on the Charges to Load in the Day-Ahead Energy Market

The IMM estimated the impact of removing supply from nuclear resources on the clearing prices of the day-ahead energy market. Two scenarios were analyzed: 10,000 MW and 20,000 MW were removed from the supply offered in the day-ahead energy market. In the IMM's simulation, expensive supply that did not clear in the day-ahead energy market would clear to replace the removed supply to satisfy the day-ahead energy market demand. Locational constraints were ignored in this simulation. In hours where enough supply was not available to satisfy the demand, the clearing price was assumed to equal the system marginal price (SMP) cap set at $3,500 per MWh.

Table 6 shows the estimated impact of removing 10,000 MW and 20,000 MW from the offered supply in the day-ahead market.

Based on clearing prices and quantities in the day-ahead market, the total load payments in 2023 were $25.2 billion.[1] If 10,000 MW of supply were removed from the day-ahead energy market and everything else had remained the same, the total day-ahead energy market charges for 2023 would have been expected to be 71.1 percent higher and between 27.9 and 114.5 percent higher with 95 percent confidence compared to the actual results.

If 20,000 MW of supply were removed from the day-ahead energy market and everything else had remained the same, the total day-ahead energy market charges for 2023 would have been expected to be 679.3 percent higher and between 638.0 and 720.8 percent higher with 95 percent confidence compared to the actual results.

Table 6 Impact on the day-ahead energy market due to the removal of nuclear supply

	Actual	Remove 10,000 Nuclear Supply in DA Energy Market		
		Expected	95% Conf LB	95% Conf UB
DA Actual Load Payment ($ per Year)	$25,227,902,389	$43,166,475,003	$32,278,309,881	$54,110,191,987
Percentage Change		71.1%	27.9%	114.5%
	Actual	**Remove 20,000 Nuclear Supply in DA Energy Market**		
		Expected	**95% Conf LB**	**95% Conf UB**
DA Actual Load Payment ($ per Year)	$25,227,902,389	$196,598,743,791	$186,190,590,529	$207,059,999,875
Percentage Change		679.3%	638.0%	720.8%

Conclusions

The sensitivity analyses demonstrate that the addition of significant new load in Maryland would significantly increase capacity and energy prices in Maryland. The addition of significant new load in PJM would also significantly increase capacity and energy prices in Maryland.

The results of the sensitivity analyses are based on the explicit assumption that co-located load is attracted by special contracts, like the proposed Susquehanna arrangement, that exempt the co-located load from paying the transmission and distribution costs that other customers pay. The assumption is that the co-located load would not otherwise locate in Maryland at or near the site of the nuclear power plant.

However, the impacts on the capacity and energy markets are very similar if the co-located customers are added as co-located load or just added as load in Maryland or in PJM, depending on the scenario.

The policy question for the Maryland PSC and for other state regulators and for FERC is: given these impacts on Maryland customers, does it make sense to provide special incentives to co-located load by allowing such load to avoid paying the costs associated with state and federal regulation that all other load must pay, including the costs of transmission, the cost of ancillary services and Maryland distribution system costs. Does

[1] The day-ahead market charges shown here do not include uplift payments and ancillary service charges.

it make sense to allow co-located load to jump the queue and not be subject to detailed analysis. Separate analysis of each individual request on a one by one basis is not sufficient. Longer term, comprehensive analysis of the likely impacts is required. Any decision on a specific case will create a precedent.