UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Large Loads Co-Located at Generating Facilities	)))	Docket No. AD24-11-000

POST TECHNICAL CONFERENCE COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

The stated purpose of this Commission technical conference is to "Discuss generic issues related to the co-location of large loads at generating facilities." "Broadly, issues to be explored at the technical conference may include whether co-located loads require the provision of wholesale transmission or ancillary services, related cost allocation issues, and potential resource adequacy, reliability, affordability, market, and customer impacts."[1]

A co-located load, as used in these comments, is a load located behind the meter of a generating unit and interconnected to the grid through the generator.[2]

New load must be served in wholesale power markets. New data center load must be served in PJM and other wholesale power markets. National security issues are about serving data center load and not about the co-located model. The only question is how to serve the potentially very large total increases in load in a way that does not threaten reliability or the ability of PJM markets to reliably serve all load at the lowest possible cost. The co-located load model is clearly not the answer. The primary proponents of the co-located model are owners of existing generation who anticipate financial benefit from contracts with co-located

1 Large Loads Co-Located at Generating Facilities, Supplemental Notice of Commissioner-Led Technical Conference (August 16, 2024).

2 The generator's substation.

loads at prices greater than market clearing prices. Specific financial arrangements do not require the co-located approach, as demonstrated by the recently announced contract associated with TMI and Microsoft. Bilateral contracts for differences can incorporate any financial arrangements preferred by the participants.

The addition of large loads is not a private decision that should be addressed via private negotiations on generator Interconnection Service Agreements (ISAs). ISAs are not private contracts beyond the purview of the regulatory process and should not be used to negotiate matters of public policy. Providing power to large data centers is a public policy matter that should be based on public, transparent discussion of the merits and implications of that policy and with review and decisions by the regulatory authorities charged with policy making responsibility. Consistent, transparent policy decisions are essential.

Contrary to assertions by some supporters of 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. This is not a complicated question requiring detailed analysis or explanations. The units that provide power to co-located load are on the grid and benefit from all grid services and could not provide service to co-located load without the grid.[3] As a result, decisions about co-located load in PJM affect all PJM customers.

One of the issues with proposals for co-located load is the definition of backup power. The definition proposed by proponents illustrates the fact that it is not possible for the designated load to be off the grid. Under existing and proposed approaches related to co-located load at sites with multiple units, one unit would give up its Capacity Interconnection Rights (CIRs) and would no longer be PJM capacity, but the co-located load would rely on the second unit for backup if the dedicated plant were on complete or partial outage for any reason. The second unit would remain a PJM capacity resource with CIRs and paid for by

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[3] The only exception would be if a unit and the co-located load are fully air gapped from the grid. In that case neither the unit nor the load would benefit from the grid as long as they remain unconnected. An option to return to the grid would mean that even that exception does not apply.

PJM customers. This definition of backup is not consistent with the assertions of proponents that co-located load is not leaning on the grid.

Power grids are built and maintained to permit all market 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 grid meets increases and decreases in individual loads. The co-located model would directly remove significant capacity from the market but the co-located load would continue to rely on grid resources for backup. As the co-located load increases and decreases for any reason, there would be a direct impact on the grid through decreased or increased power injections by the generator. 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 asserting that it is isolated from the grid.

The large impacts on PJM capacity and energy prices that would result from implementation of the co-located model are also evidence of the effect on all PJM customers. Given that PJM's excess reserves are currently less than 1,000 MW, removing a relatively small amount of MW to serve co-located load would have a significant impact on reliability and could easily result in a shortfall in reserves in PJM.

PJM must have the authority to plan for meeting large load additions in the same way that PJM plans for generation additions. While not a requirement, the addition of large data centers would be easier if the data centers brought new generation to the market in addition to new load. Some data center owners have proposed exactly that. If there is a policy decision that large data centers must be brought online more quickly, that can also be handled through the PJM planning process. The timeline for bringing load online does not depend on avoiding regulatory and planning requirements via the co-located model.

It is essential that the addition of significant new loads go through a complete PJM analysis and planning process that includes addressing system reliability and is not narrowly limited to local transmission issues, even if that process is time consuming. Every new generator and every large load addition should go 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. PJM planning should be comprehensive and include the addition or retirement of transmission, generation and load.

Adding large amounts of data center load would have impacts on PJM markets regardless of whether the load is co-located or explicitly interconnected to the grid. If the load is interconnected to the grid it should also go through the PJM planning process to ensure that the load can be met reliably through a combination of generation and transmission and that the load will pay an appropriate share of system costs. The correct market signals would be created for the location of data centers.

If the co-located load model 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.[4] Emissions would also increase as thermal resources that are next in the supply curve are dispatched to meet load to replace the nuclear energy. Even a relatively small reduction in system capacity would put PJM reliability at risk. Removal of multiple nuclear plants would significantly reduce reliability below PJM's defined reliability requirement. The co-located model would undermine PJM reliability and PJM competitive markets.

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

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4 The IMM has quantified some of the potential impacts on capacity and energy markets. *See attached* IMM Comments to the Maryland PSC re Senate Bill 1 Co-Location Study, Administrative Docket PC 61 (September 24, 2024); IMM Supplemental Comments to the Maryland PSC re Senate Bill 1 Co-Location Study, Administrative Docket PC 61 (December 13, 2024) <*https://www.monitoringanalytics.com/filings/2024/IMM_Comments_MDPSC_PC61_20240924.pdf*>.

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 and relatively long lasting impact on capacity market prices. The gains for the generation owners would come at the expense of other customers in the PJM markets. The core feature of the co-located approach is avoiding the costs associated with both state and federal regulation and avoiding the PJM planning process. The co-located load arrangement would not be directly subject to the rate regulation of the state public utility commission or the FERC.

There appears to be a growing consensus, excluding key proponents of the co-located load model, around a realistic and market based path forward. PJM's preference is to have new load explicitly connected to the grid. Statements to FERC indicate that some transmission owners with no generation agree and that some existing and potential owners of data centers agree. NERC pointed out operational issues that arise from the co-located model.[5] Data centers need power. Data centers do not need the co-located load model. The IMM recommends that the Commission develop and implement this path forward with input from all stakeholders. That consensus includes key components. PJM, and RTOs/ISOs in general, should do comprehensive planning and explicitly plan for large load additions in the same way that they plan for new generation and new transmission. There should be an orderly queue, including milestones to verify additions, and large loads should not be added until they can be reliably served without disrupting markets for other customers. Large load additions that bring matching generation online would be preferred over large load additions that did not bring matching generation but both would be part of the queue. Large loads, like

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[5] Statements about positions in this paragraph are based on statements at the FERC Commissioner led Technical Conference on Large Loads Co-Located at Generating Facilities, Docket No. AD24-11 (November 1, 2024).

all other loads, would be directly connected to the grid, rely on the grid for backup, pay for energy and capacity, and pay for transmission service based on gross load.

Respectfully submitted,

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ATTACHMENT

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

The Independent Market Monitor for PJM

September 24, 2024

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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.

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

The Independent Market Monitor for PJM

December 13, 2024

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Introduction

The Independent Market Monitor for PJM (IMM) submits an addendum to the comments previously submitted 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.

Additional Analysis of Potential Impacts

Impact on RPM Revenues

The IMM did additional 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 Peach Bottom nuclear plant in Pennsylvania; removing 10,000 MW of nuclear capacity across all PJM nuclear plants except for the Calvert Cliffs nuclear plant; and removing all nuclear capacity in PJM. The results include the increase in overall payments for capacity and the impacts to payments by customers in Maryland.

Table 1 shows the impact of removing the Peach Bottom nuclear plant in Pennsylvania 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 Peach Bottom nuclear plant in Pennsylvania 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 $21,867,647,998, an increase of $7,180,600,640, or 32.8 percent, compared to the actual results. From another perspective, inclusion of offers from Peach Bottom nuclear plant in Pennsylvania resulted in a 48.9 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had Peach Bottom nuclear plant in Pennsylvania was not offered (Scenario 6).

The cleared capacity for the entire RTO of 134,224.2 MW resulted in a reserve margin of 18.6 percent and a net excess of 870.9 MW over the reliability requirement adjusted for FRR and PRD of 133,353.3 MW.[1] If the Peach Bottom nuclear plant with more than 2,500 MW installed capacity did not offer in the capacity market, the RTO would be short of the reliability requirement. As a result, the clearing prices would be equal to the maximum price (the price coordinate of point A on the VRR curve). For the 2025/2026 RPM Base

[1] These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

Residual Auction, the price coordinate of point A ranged between $438.47 per MW-day and $496.46 per MW-day.

The IMM did an additional sensitivity analysis to evaluate the impact of removing MW equal to the unforced capacity of Calvert Cliffs, located in the SWMAAC LDA, from the larger Peach Bottom site, located in the EMAAC LDA. [2] The impact of removing the equivalent of Calvert Cliffs UCAP MW from Peach Bottom was identical to the impact of removing Calvert Cliffs capacity directly (Scenario 2).[3]

The identical impact would not occur under all market conditions. In the 2025/2026 BRA, there was no price separation between the MAAC LDA and its child LDAs, EMAAC and SWMAAC. The MAAC LDA cleared as a single LDA, with the exception of the BGE LDA. In addition, the maximum price on the VRR curves for EMAAC and SWMAAC LDAs were identical. If the parameters and offers were different, the impact of removing the equivalent of Calvert Cliffs capacity from the Peach Bottom capacity could differ from removing the Calvert Cliffs capacity.

Table 2 shows the impact of removing 10,000 UCAP MW from all nuclear capacity in PJM except for the Calvert Cliffs nuclear plant 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 in total from all nuclear capacity in PJM except for Calvert Cliffs nuclear plant 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 $20,850,062,537, an increase of $6,163,015,180, or 29.6 percent, compared to the actual results. From another perspective, inclusion of offers from 10,000 UCAP MW in total from all nuclear capacity in PJM except for Calvert Cliffs nuclear plant resulted in a 42.0 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 in total from all nuclear capacity in PJM except for Calvert Cliffs nuclear plant was not offered (Scenario 7).

If 10,000 UCAP MW from all nuclear capacity did not offer in the capacity market, the RTO would be short of the reliability requirement. As a result, the clearing prices would be equal to the maximum price (the price coordinate of point A on the VRR curve). For the 2025/2026 RPM Base Residual Auction, the price coordinate of point A ranged between $438.47 per MW-day and $496.46 per MW-day. The total RPM market revenues for the 2025/2026 RPM Base Residual Auction under Scenario 7 would be lower than the total

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2 The installed capacity of Calvert Cliffs nuclear resource is 1,770.2 MW. For this scenario, the offered unforced capacity of the Calvert Cliffs nuclear resource was removed from the Peach Bottom nuclear resource.

3 See Comments to the Maryland PSC Senate Bill 1 Co-location Study Administrative Docket PC 61 (September 24, 2024).

RPM market revenues under Scenario 6 as a result of the reduced amount of capacity offered and cleared. Under Scenario 7, 133,258.3 UCAP MW would clear, while under Scenario 6 125,704.2 UCAP MW would clear the capacity market. If the price is equal to the maximum price, a reduction in offered and cleared MW results in a reduction in total market revenue and a reduction in reliability.

Table 3 shows the impact of removing 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 all 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 $17,815,985,799, an increase of $3,128,938,441, or 42.1 percent, compared to the actual results. From another perspective, inclusion of offers from nuclear capacity in PJM resulted in a 21.3 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had nuclear capacity in PJM was not offered (Scenario 8).

If all nuclear capacity in PJM did not offer in the Capacity market, the RTO would be short of the reliability requirement. As a result, the clearing prices would be equal to the maximum price (the price coordinate of point A on the VRR curve). For the 2025/2026 RPM Base Residual Auction, the price coordinate of point A ranged between $438.47 per MW-day and $496.46 per MW-day. The total RPM market revenues for the 2025/2026 RPM Base Residual Auction under Scenario 8 would be lower than the total RPM market revenues under Scenario 6 and Scenario 7 as a result of the reduced amount of capacity offered and cleared. Under Scenario 7, 133,258.3 UCAP MW would clear, under Scenario 6 125,704.2 UCAP MW would clear and under Scenario 8, 107,226.9 UCAP MW would clear the capacity market. If the price is equal to the maximum price, a reduction in offered and cleared MW results in a reduction in total market revenue and a reduction in reliability.

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		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
6	Remove Peach Bottom Nuclear Resource	$21,867,647,998	($7,180,600,640)	(32.8%)	48.9%
7	Remove 10,000 UCAP MW in total from all nuclear resources offered in BRA except for Calvert Cliffs	$20,850,062,537	($6,163,015,180)	(29.6%)	42.0%
8	Remove all nuclear resources offered in BRA	$17,815,985,799	($3,128,938,441)	(17.6%)	21.3%

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
6	Remove Peach Bottom Nuclear Resource	133,258.3	2,425.7	1.8%	(1.8%)
7	Remove 10,000 UCAP MW in total from all nuclear resources offered in BRA except for Calvert Cliffs	125,704.2	9,979.8	7.9%	(7.4%)
8	Remove all nuclear resources offered in BRA	107,226.9	28,457.1	26.5%	(21.0%)

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 6. 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 the Peach Bottom nuclear plant in Pennsylvania 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 $1,746,218,711, an increase of $619,759,347, or 55.0 percent higher than in the 2025/2026 BRA.

Table 3 Net load charges for Maryland (Scenario 6)

	Remove Peach Bottom Nuclear Resource					
	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	$267,879,203	$0	$267,879,203
BGE	$1,026,536,627	$357,767,342	$668,769,284	$1,010,160,733	$18,109,192	$992,051,541
DPL	$113,156,485	$0	$113,156,485	$189,987,101	$252,040	$189,735,061
Pepco	$178,742,689	$0	$178,742,689	$296,552,905	$0	$296,552,905
Total Maryland	$1,484,226,706	$357,767,342	$1,126,459,364	$1,764,579,943	$18,361,232	$1,746,218,711

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 10,000 UCAP MW in total from all nuclear capacity in PJM except for Calvert Cliffs nuclear plant 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 $1,652,555,068, an increase of $526,095,705, or 46.7 percent higher than in the 2025/2026 BRA.

Table 4 Net load charges for Maryland (Scenario 7)

	Remove 10,000 UCAP MW in total from all nuclear resources offered in BRA except Calvert Cliffs					
	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	$256,227,824	$0	$256,227,824
BGE	$1,026,536,627	$357,767,342	$668,769,284	$952,904,357	$16,876,903	$936,027,454
DPL	$113,156,485	$0	$113,156,485	$181,024,336	$466,758	$180,557,579
Pepco	$178,742,689	$0	$178,742,689	$279,742,211	$0	$279,742,211
Total Maryland	$1,484,226,706	$357,767,342	$1,126,459,364	$1,669,898,729	$17,343,661	$1,652,555,068

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 all 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 $1,410,735,066, an increase of $284,275,703, or 25.2 percent higher than in the 2025/2026 BRA.

Table 5 Net load charges for Maryland (Scenario 8)

	Remove 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	$219,114,238	$0	$219,114,238
BGE	$1,026,536,627	$357,767,342	$668,769,284	$812,908,847	$13,862,728	$799,046,119
DPL	$113,156,485	$0	$113,156,485	$154,416,729	$466,758	$153,949,971
Pepco	$178,742,689	$0	$178,742,689	$238,624,738	$0	$238,624,738
Total Maryland	$1,484,226,706	$357,767,342	$1,126,459,364	$1,425,064,552	$14,329,486	$1,410,735,066