Potential Impacts of the Creation of Virginia FRRs

The Independent Market Monitor for PJM

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Summary

The Independent Market Monitor for PJM (IMM or MMU) analyzed the impacts of the creation of Fixed Resource Requirement (FRR) entities in Virginia. FRR entities elect to not participate in the PJM Capacity Market and to use the FRR option to satisfy their capacity obligations. Under the FRR option, Load Serving Entities (LSEs) in Virginia would need to meet their FRR capacity obligations through owned generation and bilateral contracts with the owners of capacity, primarily within the AEP, APS, Dominion and DPL Zones. Virginia has more capacity than needed to meet the FRR obligation. The IMM analyzed eight scenarios. Separate Locational Deliverability Areas (LDAs) for AEP, APS and DPL were not analyzed because of their relatively small load obligations. The load obligations of AEP, APS and DPL together account for less than six percent of the total load obligation of Virginia.

Of the four zones (AEP, APS, Dominion and DPL) in Virginia, none is entirely within Virginia. The AEP Zone, APS Zone and Dominion Zone are not modeled LDAs and are part of the Rest of RTO LDA, which is a part of the RTO parent LDA. The Virginia portion of the DPL Zone is a part of the DPL South LDA, which is a part of the EMAAC parent LDA.

For consistency and comparability, the IMM analysis of FRR options in Virginia uses the same approach that the IMM used in each of its prior FRR analyses. But Virginia is unique in that the utility companies are vertically integrated utilities subject to cost of service regulation and the public power entities in Virginia also are subject to their own form of cost of service regulation. An evaluation of the likely results of any of the FRR options must recognize that cost of service regulation does and will define the level of payments for these entities rather than a new program of subsidies. Customers in Virginia pay a net cost of capacity that is a result of regulated cost of service rates net of the impact of the sale and purchase of capacity in the PJM Capacity Market. If customers pay the market price of capacity and receive offsetting revenues equal to the market price of capacity, customers are indifferent to the capacity market price and pay the regulated cost of capacity. The IMM did not evaluate the details of state regulation of Dominion or of the regulatory details of the other entities and therefore did not evaluate the extent to which customers currently pay more under regulated rates than the market price of capacity. Correspondingly, the IMM did not evaluate the extent to which customers would lose benefits from the loss of revenues from the sale of capacity in the PJM Capacity Market. Nonetheless, this analysis puts the impacts of a range of FRR scenarios in context, including the impact on the PJM Capacity Market.

The results of each scenario should be interpreted in light of the regulatory status of the entities. The scenario results, for consistency and comparability with prior IMM FRR analyses, assume that all Virginia customers paid capacity market prices for all capacity. The market prices can be used as a benchmark for whether Virginia customers paid more or less than the market value of capacity and whether Virginia customers would

pay more or less than the price in the identified FRR options. Scenario results should be interpreted carefully, given that Virginia customers paid regulated cost of service rates for capacity that are not equal to capacity market prices and are likely to exceed capacity market prices.

In Scenario 1, the IMM assumes that an FRR is established that includes all of Virginia and that the FRR procures the entire Virginia capacity obligation at a rate equal to the weighted average net Cost of New Entry (CONE) times B offer caps applicable to the LDAs in Virginia ($233.48 per MW-day) for the 2021/2022 PJM Reliability Pricing Model (RPM) Base Residual Auction (BRA). The IMM concludes that under Scenario 1, net load charges for Virginia under the FRR alternative would increase by $685.9 million or 59.3 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

In Scenario 2, the IMM assumes that an FRR is established that includes all of Virginia and that the FRR procures the entire Virginia capacity obligation at a rate equal to the weighted average clearing prices in the 2021/2022 RPM BRA applicable to the LDAs in Virginia ($140.17 per MW-day). The IMM concludes that under Scenario 2, the net load charges for Virginia under the FRR alternative would decrease by $50.8 million or 4.4 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

For both Scenarios 1 and 2, the IMM also analyzed the impacts on the RTO, excluding Virginia. In both scenarios, the Rest of RTO clearing price would decrease by $50.00 per MW-day to $90.00 per MW-day, or 35.7 percent compared to the results of the 2021/2022 RPM BRA. In both scenarios, the EMAAC clearing price would decrease by $0.73 per MW-day to $165.00 per MW-day, or 0.4 percent. In both scenarios, the clearing price of the DEOK LDA would decrease by $11.53 per MW-day to $128.47 per MW-day, or 8.2 percent. Net load charges for the RTO excluding Virginia would be lower by $1,338.3 million or 16.3 percent compared to the 2021/2022 RPM BRA net load charges.

In Scenario 3, the IMM assumes that an FRR is established for the Virginia portion of the Dominion LSE, the Virginia portion of Old Dominion Electric Cooperative (ODEC), Northern Virginia Electric Cooperative and Central Virginia Electric Cooperative (Dominion/Virginia and Cooperatives FRR) and that the FRR procures the entire Dominion/Virginia and Cooperatives capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for the applicable LDAs in the FRR service area ($233.47 per MW-day). The rest of Virginia remains in the PJM Capacity Market. The IMM concludes that under Scenario 3 net load charges for Dominion/Virginia and Cooperatives under the FRR alternative would increase by $675.5 million or 59.3 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

In Scenario 4, the IMM assumes that an FRR is established for the Virginia portion of the Dominion LSE, the Virginia portion of ODEC, Northern Virginia Electric Cooperative and Central Virginia Electric Cooperative (Dominion/Virginia and Cooperatives FRR) and that the FRR procures the entire Dominion/Virginia and Cooperatives capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($140.18 per MW-day). The IMM concludes that under Scenario 4 the net load charges for Dominion/Virginia and Cooperatives under the FRR alternative would decrease by $49.7 million or 4.4 percent compared the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

For both Scenarios 3 and 4, the IMM also analyzed the impacts on the RTO, excluding the Dominion/Virginia and Cooperatives FRR. In both scenarios, the Rest of RTO clearing price would decrease by $48.04 per MW-day to $91.96 per MW-day, or 34.3 percent compared to the results of the 2021/2022 RPM BRA. In both scenarios, the EMAAC clearing price would decrease by $0.26 per MW-day to $165.47 per MW-day, or 0.2 percent. In both scenarios, the DEOK clearing price would decrease by $11.53 per MW-day to $128.47 per MW-day, or 8.2 percent. Net load charges for the RTO excluding the Dominion/Virginia and Cooperatives FRR would be lower by $1,289.5 million or 15.6 percent compared to the 2021/2022 RPM BRA net load charges.

For both Scenarios 3 and 4, the IMM also analyzed the net impact on Virginia. In both Scenarios 3 and 4, the net load charges for Virginia, excluding the Dominion/Virginia and Cooperatives FRR, would decrease by $6.2 million or 33.7 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

In Scenario 3, the net load charges for all Virginia, including the Dominion/Virginia and Cooperatives FRR, would increase by $669.3 million or 57.8 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

In Scenario 4, the net load charges for all Virginia, including the Dominion/Virginia and Cooperatives FRR, would decrease by $55.8 million or 4.8 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

In Scenario 5, the IMM assumes that an FRR is established for the Virginia portion of the Dominion LSE (Dominion/Virginia FRR) and that the Dominion/Virginia FRR procures the entire Dominion/Virginia FRR capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for the Dominion Zone ($234.13 per MW-day). The rest of Virginia remains in the PJM Capacity Market. The IMM concludes that under Scenario 5, net load charges for the Dominion/Virginia FRR under the FRR alternative would increase by $559.7 million or 60.1 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

In Scenario 6, the IMM assumes that an FRR is established for the Virginia portion of the Dominion LSE (Dominion/Virginia FRR) and that the Dominion/Virginia FRR procures the entire Dominion/Virginia capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($140.00 per MW-day). The IMM concludes that under Scenario

6 the net load charges for the Dominion/Virginia FRR under the FRR alternative would decrease by $39.9 million or 4.3 percent compared the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

For both Scenarios 5 and 6, the IMM also analyzed the impacts on the RTO, excluding the Dominion/Virginia FRR. In both scenarios, the Rest of RTO clearing price would decrease by $13.21 per MW-day to $126.79 per MW-day, or 9.4 percent compared to the results of the 2021/2022 RPM BRA. The DEOK clearing price would decrease by $11.53 per MW-day to $128.47 per MW-day, or 8.2 percent. In both scenarios, the net load charges for the RTO excluding the Dominion/Virginia would be lower by $384.2 million or 4.5 percent compared to the 2021/2022 RPM BRA net load charges.

For both Scenarios 5 and 6, the IMM also analyzed the impact on Virginia. In both scenarios, the net load charges for Virginia, excluding the Dominion/Virginia FRR, would decrease by $20.3 million or 9.0 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

In Scenario 5, the net load charges for all Virginia, including the Dominion/Virginia FRR, would increase by $539.4 million or 46.6 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

In Scenario 6, the net load charges for all Virginia, including the Dominion/Virginia FRR, would decrease by $60.2 million or 5.2 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

In Scenario 7, the IMM assumes that an FRR is established for the Virginia portion of the Dominion LSE and Virginia portion of ODEC (Dominion/Virginia and ODEC FRR) and that the FRR procures the entire Dominion/Virginia and ODEC capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for the applicable LDAs in the FRR service area ($233.42 per MW-day). The rest of Virginia remains in the PJM Capacity Market. The IMM concludes that under Scenario 7 net load charges for Dominion/Virginia and ODEC under the FRR alternative would increase by $633.1 million or 59.2 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

In Scenario 8, the IMM assumes that an FRR is established for the Virginia portion of the Dominion LSE, Virginia portion of ODEC (Dominion/Virginia and ODEC FRR) and that the FRR procures the entire Dominion/Virginia and ODEC capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($140.19 per MW-day). The IMM concludes that under Scenario 8 the net load charges for Dominion/Virginia and ODEC under the FRR alternative would decrease by $46.6 million or 4.4 percent compared the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

For both Scenarios 7 and 8, the IMM also analyzed the impacts on the RTO, excluding the Dominion/Virginia and ODEC FRR. In both scenarios, the Rest of RTO clearing price would decrease by $30.05 per MW-day to $109.95 per MW-day, or 21.5 percent compared to the results of the 2021/2022 RPM BRA. In both scenarios, the EMAAC clearing price would decrease by $0.26 per MW-day to $165.47 per MW-day, or 0.2 percent. In both scenarios, the DEOK clearing price would decrease by $11.53 per MW-day to $128.47 per MW-day, or 8.2 percent. Net load charges for the RTO excluding the Dominion/Virginia and ODEC FRR would be lower by $824.2 million or 9.9 percent compared to the 2021/2022 RPM BRA net load charges.

For both Scenarios 7 and 8, the IMM also analyzed the net impact on Virginia. In both Scenarios 7 and 8, the net load charges for Virginia, excluding the Dominion/Virginia and ODEC FRR, would decrease by $18.7 million or 21.1 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

In Scenario 7, the net load charges for all Virginia, including the Dominion/Virginia and ODEC FRR, would increase by $614.3 million or 53.1 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

In Scenario 8, the net load charges for all Virginia, including the Dominion/Virginia and ODEC FRR, would decrease by $65.4 million or 5.6 percent compared to the results of the 2021/2022 RPM BRA, if Virginia load paid capacity market prices prior to implementation of an FRR.

Table 1 presents a summary of the results for all eight scenarios including the impact on net load charges: for the defined FRRs; for Virginia excluding the defined FRRs; for all of Virginia including the defined FRRs and the non FRR portions of Virginia; and for the rest of the PJM market, where the rest of the PJM market includes the non FRR portions of Virginia when relevant. (The detailed results about the impacts on Virginia load assume that Virginia load paid capacity market prices prior to implementation of an FRR.)

Table 1 Scenario summary

	FRR		Rest of Virginia		Virginia		Rest of PJM Market	
Scenario	Change	Percent	Change	Percent	Change	Percent	Change	Percent
1	$685,893,404	59.3%	NA	NA	$685,893,404	59.3%	($1,338,280,878)	(16.3%)
2	($50,801,765)	(4.4%)	NA	NA	($50,801,765)	(4.4%)	($1,338,280,878)	(16.3%)
3	$675,501,526	59.3%	($6,178,027)	(33.7%)	$669,323,500	57.8%	($1,289,470,953)	(15.6%)
4	($49,667,480)	(4.4%)	($6,178,027)	(33.7%)	($55,845,506)	(4.8%)	($1,289,470,953)	(15.6%)
5	$559,708,197	60.1%	($20,294,796)	(9.0%)	$539,413,401	46.6%	($384,213,185)	(4.5%)
6	($39,921,410)	(4.3%)	($20,294,796)	(9.0%)	($60,216,206)	(5.2%)	($384,213,185)	(4.5%)
7	$633,070,202	59.2%	($18,743,155)	(21.1%)	$614,327,047	53.1%	($824,166,648)	(9.9%)
8	($46,641,135)	(4.4%)	($18,743,155)	(21.1%)	($65,384,290)	(5.6%)	($824,166,648)	(9.9%)

The actual price for capacity in Virginia would continue to be the result of the regulatory process, and the actual impacts would be determined by the details of the state regulatory process.

Creation of an FRR creates market power for the local generation owners from whom generation must be purchased in order to meet the reliability requirements of the FRR entities. All participants in the Virginia, Dominion/Virginia and Cooperatives, Dominion/Virginia, and Dominion/Virginia and ODEC FRRs fail the three pivotal supplier test which reinforces the conclusion that there is structural market power in each case. The FRR approach is a nonmarket approach. The traditional regulatory process in Virginia and elsewhere was designed to address market power. The way in which market power would be addressed under cost of service regulation would not be expected to change.

Under the existing FRR design, FRR entities have a lower capacity obligation than the corresponding LDAs have in the PJM market. Regardless of the reason for this design element, it is an example of an RTO design element that could easily be changed if other market participants believed that it unfairly assigns a disproportionately small share of the overall responsibility for PJM capacity obligations to the FRR entity or entities.

Under the existing FRR design, generators in FRR entities have weaker performance obligations and incentives than generators in the corresponding LDAs in the PJM market. Regardless of the reason for this rule, it is also an example of an RTO rule that could easily be changed if other market participants believed that it unfairly assigns a disproportionately small share of the overall responsibility for PJM capacity resources to perform during high demand hours to the FRR entity or entities.

Introduction

In this report, the IMM analyzes the rules governing the FRR alternative to direct participation in the PJM Capacity Market and a range of potential impacts of creating a Virginia FRR service area both on payments by customers in Virginia and by customers in the balance of the RTO, based on explicitly stated assumptions.[1] The IMM previously published reports on the impacts of a ComEd FRR, a set of Maryland FRRs, a set of New Jersey FRRs, a set of Ohio FRRs and a District of Columbia FRR, but the public discussion of potential FRRs in other LDAs has not been supported by analysis to date.[2] [3]

1 See Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA"), Article 1 and Schedule 8.1.

2 "Potential Impacts of the Creation of a ComEd FRR," Monitoring Analytics, LLC, <http://www.monitoringanalytics.com/reports/Reports/2019.shtml> (December 18, 2019).

[4] [5] [6] The IMM will provide analyses of the outcomes under different assumptions and of other potential FRRs, upon request. The IMM previously provided comparable analysis of FERC's resource specific FRR approach and of PJM's extended resource carve out proposal or repricing approach.[7] The IMM also provided an analysis of the impact of the MOPR order on prices in the upcoming BRA.[8]

The American Electric Power Company, Inc. (AEP) created the first FRR service area based on the original RPM tariff rules implemented in 2007.[9] AEP was a vertically integrated utility (transmission, generation and distribution assets) which participated in all the other PJM markets, but which, rather than participating in the PJM Capacity Market, received payment for generation capacity well in excess of capacity market prices, based on a cost of service model, under a regulatory arrangement with Ohio.

In order to create a new FRR service area, a utility (investor owned, electric cooperative or public power entity) must elect the FRR option consistent with the PJM Market Rules. The utility can make a voluntary FRR election or be required to make the FRR election by the state in which the FRR exists.

There are four transmission zones in Virginia: American Electric Company (AEP), Allegheny Power Company (APS), Dominion, and Delmarva Power and Light (DPL). Virginia could require that all LSEs located in the state elect FRR status or that all LSEs

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3 "Potential Impacts of the Creation of Maryland FRRs," Monitoring Analytics, LLC, <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).

4 "Potential Impacts of the Creation of New Jersey FRRs," Monitoring Analytics, LLC, <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRs_202000513.pdf> (May 13, 2020).

5 "Potential Impacts of the Creation of Ohio FRRs," Monitoring Analytics, LLC, <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).

6 "Potential Impacts of the Creation of District of Columbia FRR," Monitoring Analytics, LLC, <https://www.monitoringanalytics.com/Reports/Reports/2021/IMM_Potential_Impact_of_the Creation_of_District_of_Columbia_FRR_20210507.pdf> (May 7, 2021).

7 See Monitoring Analytics, LLC "MOPR/FRR Sensitivity Analyses of the 2021/2022 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_MOPR_FRR_Sensitivity_Analyses_Report_20180926.pdf> (September 26, 2018).

8 See Monitoring Analytics, LLC "Potential Impacts of the MOPR Order," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_MOPR_Order_20200320.pdf> (March 20, 2020).

9 See RAA Schedule 8.1; 117 FERC ¶ 61,331 (2006) at PP 36, 113.

in specific zones elect FRR status.[10] Regardless of the existence of retail choice, the FRR entity must include all load in the FRR service area and must provide adequate capacity to meet that load. In the AEP case, AEP owned enough generation assets to meet its PJM defined UCAP obligation. Similarly, in Virginia, there are more than enough capacity resources to meet the PJM defined FRR UCAP obligation.

The analysis in this report is based on the actual auction inputs and results for the PJM Reliability Pricing Model (RPM) BRA (BRA) for the 2021/2022 Delivery Year, the last BRA run.[11]

The IMM evaluated the results of creating a Virginia FRR service area for load in Virginia and for the rest of the capacity market, under eight scenarios. The impacts on Virginia load all assume that Virginia load paid capacity market prices prior to implementation of an FRR.

- Scenario 1: An FRR is established that includes all of Virginia and the FRR procures the entire Virginia capacity obligation at a rate equal to the weighted average of the 2021/2022 net CONE times B offer caps applicable to the LDAs in Virginia ($233.48 per MW-day).
- Scenario 2: An FRR is established that includes all of Virginia and the FRR procures the entire Virginia capacity obligation at a rate equal to the weighted average clearing prices in the 2021/2022 RPM BRA applicable to LDAs in Virginia ($140.17 per MW-day).
- Scenario 3: An FRR is established for the Dominion/Virginia and Cooperatives and the FRR procures the entire Dominion/Virginia and Cooperatives capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap applicable to the LDAs in the FRR service area ($233.47 per MW-day).
- Scenario 4: An FRR is established for the Dominion/Virginia and Cooperatives and the FRR procures the entire Dominion/Virginia and Cooperatives capacity obligation

10 An FRR entity is required to meet the capacity obligations of all alternative retail LSEs in the FRR service area. The alternative retail LSEs are required to compensate the FRR entity based on a state mandated compensation mechanism or based on the Rest of RTO capacity price, in the absence of a state compensation mechanism. For any delivery year subsequent to those addressed in the FRR entity's current FRR capacity plan, the alternative retail LSE may satisfy the load payment to the FRR entity with capacity resources.

11 Participant behavior and market performance were evaluated as not competitive in the 2021/2022 RPM Base Residual Auction. See Monitoring Analytics, LLC, "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> (August 24, 2018).

at a rate equal to the clearing price in the 2021/2022 RPM BRA applicable to the LDAs in the FRR service area ($140.18 per MW-day).

- Scenario 5: An FRR is established for the Dominion/Virginia and the FRR procures the entire Dominion/Virginia capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for Dominion Zone ($234.13 per MW-day).
- Scenario 6: An FRR is established for the Dominion/Virginia and the FRR procures the entire Dominion/Virginia capacity obligation at a rate equal to the clearing price applicable to the Dominion Zone in the 2021/2022 RPM BRA ($140.00 per MW-day).
- Scenario 7: An FRR is established for the Dominion/Virginia and ODEC and the FRR procures the entire Dominion/Virginia and ODEC capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap applicable to the LDAs in the FRR service area ($233.42 per MW-day).
- Scenario 8: An FRR is established for the Dominion/Virginia and ODEC and the FRR procures the entire Dominion/Virginia and ODEC capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA applicable to the LDAs in the FRR service area ($140.19 per MW-day).

Assumptions

1. In Scenarios 1 and 2, the PJM Capacity Market would not include Virginia. In Scenarios 3 and 4, the PJM Capacity Market would not include the Virginia portion of Dominion LSE, Virginia portion of ODEC, Northern Virginia Electric Cooperative and Central Virginia Electric Cooperative (Dominion/Virginia and Cooperatives). In Scenarios 5 and 6, the PJM Capacity Market would not include the Virginia portion of the Dominion LSE (Dominion/Virginia). In Scenarios 7 and 8, the PJM Capacity Market would not include Virginia portion of Dominion LSE, Virginia portion of ODEC (Dominion/Virginia and ODEC)
2. In Scenarios 1 and 2, the FRR service area would include all of Virginia. In Scenarios 3 and 4, the FRR service area would include Dominion/Virginia and Cooperatives. In Scenarios 5 and 6, the FRR service area would include Dominion/Virginia. In Scenarios 7 and 8, the FRR service area would include Dominion/Virginia and ODEC.
3. There would be capacity exports from Virginia FRRs only from capacity resources not needed for meeting the FRR obligation. The capacity exports from the FRR entity would be capped at the maximum allowed under the current PJM rules.
4. All capacity resources would be eligible to meet FRR reliability requirements. This includes matched seasonal resources with an annual equivalent offer price less than or equal to the rate paid to all annual capacity resources in the FRR service area.
5. Unmatched seasonal resources would offer their capacity in the PJM Capacity Market. These resources would be mapped to the relevant parent LDA.
6. All resources that do not enter a contract with a Virginia FRR would offer their capacity resources in the PJM Capacity Market.

7. The MW capacity of energy efficiency resources that are part of the FRR plan would be added back to the FRR obligation.[12]

Market Structure

Table 2 shows the Virginia generation capacity resources in terms of installed capacity (ICAP).

Table 2 Generation capacity resources by transmission zone in Virginia

Zone	ICAP (MW)	Percent
AEP	939.0	3.5%
APS	3.0	0.0%
Dominion	25,276.0	94.9%
DPL	415.4	1.6%
Total	26,633.4	100.0%

Table 3 shows the installed capacity by fuel source for the capacity resources located in Virginia.[13]

Table 3 Installed capacity by fuel source[14]

Modeled LDA	Zone	Coal	Gas	Nuclear	Oil	Solar	Solid Waste	Hydroelectric	Wind	DR	EE	PRD	Total
Rest of RTO	AEP	610.0	325.0	0.0	0.0	0.0	0.0	4.0	0.0	46.9	1.8	0.0	987.7
Rest of RTO	APS	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	76.9	3.4	0.0	83.2
Rest of RTO	Dominion	2,734.8	13,623.2	3,576.0	1,838.4	219.7	400.3	2,883.6	0.0	994.1	481.9	0.0	26,751.9
DPL South	DPL	0.0	0.0	0.0	356.2	59.2	0.0	0.0	0.0	2.3	0.5	0.0	418.1
Total Virginia		3,344.8	13,951.2	3,576.0	2,194.6	278.9	400.3	2,887.6	0.0	1,120.1	487.6	0.0	28,241.0

12 The FRR obligation is based on the PJM peak load forecast for the delivery year. The PJM peak load forecast accounts for the contribution of energy efficiency resources to reducing demand. To avoid double counting, the amount of energy efficiency capacity included in the FRR plan is added back to the FRR obligation.

13 The ICAP MW values reflect administrative reductions applied by PJM to the capabilities of wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity.

14 ICAP values, rather than UCAP, are used for confidentiality reasons and the ICAP values represent resources that were offered into the 2021/2022 RPM Base Residual Auction. Resources that were not offered into 2021/2022 RPM Base Residual Auction are not included in this table. Seasonal resources that were offered into the 2021/2022 RPM Base Residual Auction but were not matched and included as FRR capacity for this study are not included in this table.

On April 11, 2020, the Virginia legislature passed a new law that replaces Virginia's current voluntary renewable portfolio standard (RPS) with a mandatory RPS.[15] The new law requires by 2050 that 100 percent of energy sold by Phase I utilities must come from RPS eligible resources; and 100 percent of energy sold by Phase II utilities must come from RPS eligible resources by 2045.[16] Intermediate RPS targets begin in 2021 with a 6.0 percent standard for phase I utilities and a 14.0 percent standard for phase II utilities. Eligible RPS resources include wind, solar, hydroelectric, landfill gas and biomass resources.

The most recent data from Virginia shows that renewable energy production from Virginia resources was 1,855.1 GWh in 2019, or 1.9 percent of Virginia energy production in 2019.[17] In 2018, renewable energy production from Virginia resources was 1,063.9 GWh, or 1.1 percent of Virginia energy production.

On July 1, 2019, Dominion Energy announced the beginning of construction on an offshore wind demonstration project. The project consists of two 6 MW offshore wind turbines.[18] In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.[19]

Market share is calculated by dividing the output of a supplier by total supply in a market. Concentration ratios are a summary measure of market share. The Herfindahl-Hirschman Index (HHI) concentration ratio is calculated by summing the squares of the market shares of all firms in a market.

FERC's Merger Policy Statement states that a market can be broadly characterized as: unconcentrated if the market HHI is below 1000, equivalent to 10 firms with equal market shares; moderately concentrated if the market HHI is between 1000 and 1800;

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15 See "Virginia Clean Economy Act," <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.

16 APCO (AEP) is a Phase I utility and Dominion Energy Virginia is a Phase II utility. Cooperatives are not subject to the RPS.

17 Renewable total includes solar and run of river hydroelectric. There was no generation from wind resources and generation by pumped storage hydroelectric facilities is not included.

18 "Construction Begins on Dominion Energy Offshore Wind Project," Dominion Energy News Release (July 1, 2019) <https://news.dominionenergy.com/2019-07-01-Construction-Begins-on-Dominion-Energy-Offshore-Wind-Project>.

19 "Dominion Energy Announces Largest Offshore Wind Project in US," Dominion Energy News Release (September 19, 2019) <https://news.dominionenergy.com/2019-09-19-Dominion-Energy-Announces-Largest-Offshore-Wind-Project-in-US>.

and highly concentrated if the market HHI is greater than 1800, equivalent to between five and six firms with equal market shares.[20]

Table 4 shows the HHI results for the FRRs analyzed. The HHI results show that the Dominion; Dominion, APS, and DPL; and Virginia FRRs are highly concentrated.

Table 4 HHI results

Market	HHI
Dominion	5622
Dominion, APS, and DPL	5478
Virginia	5429

The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the capacity market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in a market even when the HHI level is not in the highly concentrated range. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the ownership structure of supply available to meet it.

A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the pivotal supplier test are measured by the residual supply index (RSI_X). The RSI_X is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_X is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices.

Table 5 shows the results of the pivotal supplier test for the FRRs analyzed. All participants in the FRRs analyzed fail the one and three pivotal supplier tests (RSI is less than 1.0).[21]

[20] See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement, 77* FERC ¶ 61,263 *mimeo* at 80 (1996).

[21] The one pivotal supplier test and the three pivotal supplier test here include all market supply and all market demand for each FRR.

Table 5 Pivotal supplier results

Market	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
Dominion LSE	0.37	0.17	19	19
Dominion LSE and ODEC	0.34	0.17	21	21
Dominion LSE and Cooperatives	0.32	0.16	21	21
Virginia	0.33	0.16	23	23

AEP has a previously created FRR service area. The unforced capacity obligation of the FRR service areas is based on the peak load forecast for the delivery year. A part of AEP's existing FRR service area is located in Virginia.

Figure 1 shows the peak load forecast for the AEP Zone, the portion of the AEP Zone that is in the PJM Capacity Market and the portion of the AEP Zone that is in Virginia. The peak load forecast for the 2021/2022 BRA for the AEP Zone was 22,124.0 MW. The peak load forecast for the portion of the AEP Zone in the PJM Capacity Market was 10,914.7 MW or 49.3 percent of the AEP Zone's peak load forecast. The peak load forecast of the portion of the AEP Zone in Virginia that is in the PJM Capacity Market was 306.7 MW or 1.4 percent of the AEP Zone's peak load forecast, or 2.8 percent of the portion of the AEP Zone's peak load forecast located in in the PJM Capacity Market.

Figure 1 Distribution of peak load forecast for the AEP Zone for the 2021/2022 BRA

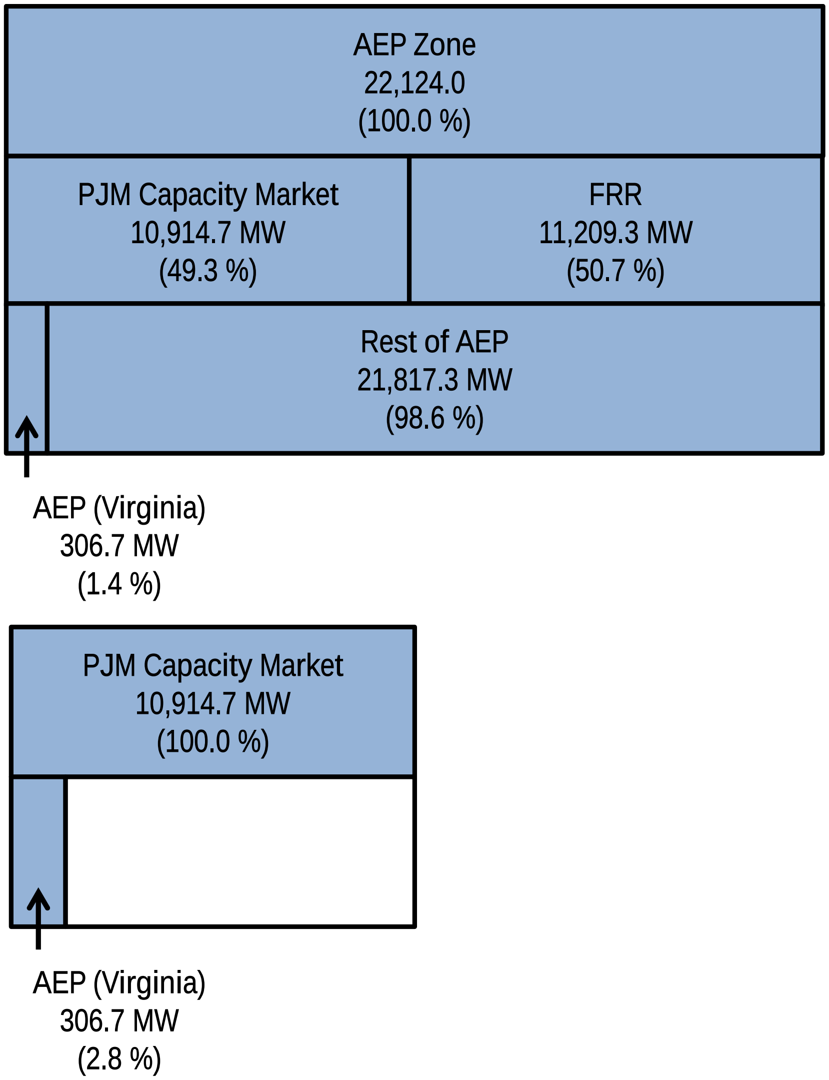


Table 6 shows the zonal UCAP obligation for each zone in Virginia. None of the four zones in Virginia (AEP, APS, Dominion and DPL) is entirely located in Virginia. This is the capacity obligation assigned to Virginia and each Virginia zone in the PJM Capacity Market. For example, the zonal UCAP obligation for the entire Dominion Zone is 22,505.4 MW. The share of peak load of the Virginia portion of the Dominion Zone is 94.2 percent. Virginia's share of the Dominion Zone zonal UCAP obligation is 21,205.7

MW. The total Virginia zonal UCAP obligation for the 2021/2022 Delivery Year is 22,543.4 MW.[22]

Table 7 shows the 2021/2022 BRA zonal UCAP obligation corresponding to the FRR service areas for each scenario. In Scenario 3 and Scenario 4, an FRR is established for the Virginia portion of the Dominion LSE, Virginia portion of ODEC, Northern Virginia Cooperative and Central Virginia Cooperative. The FRR service area in this scenario includes the Virginia portion of APS Zone, Virginia portion of the DPL Zone and Virginia portion of Dominion LSE. The zonal UCAP obligation of the service area is 22,186.3 MW.

Table 6 Virginia share of the zonal UCAP obligation by transmission zone

Zone	Share of the Peak Load (Percent)	Zonal UCAP Obligation (MW)	Virginia Share of Zonal UCAP Obligation (MW)
AEP	2.8%	12,707.7	357.1
APS	8.0%	10,317.8	827.6
Dominion	94.2%	22,505.4	21,205.7
DPL	3.5%	4,373.0	152.9
Virgina		49,903.9	22,543.4

Table 7 Zonal UCAP obligation by Scenario

Scenario	Service Area	Zones	Zonal UCAP Obligagion
1 and 2	Virginia	AEP, APS, Dominion and DPL	22,543.4
3 and 4	Dominion LSE and Cooperatives	APS, Dominion and DPL	22,186.3
5 and 6	Dominion LSE	Dominion	18,164.8
7 and 8	Dominion LSE and ODEC	APS, Dominion and DPL	20,809.2

Table 8 shows the potential FRR UCAP MW obligation for each zone in Virginia. Among the four zones in Virginia (AEP, APS, Dominion and DPL), none is entirely located in Virginia. This is the capacity obligation that would be assigned to Virginia and each Virginia zone if each were an FRR. The FRR obligation includes the EE add back. The FRR obligation is based on the PJM peak load forecast for the delivery year. The PJM peak load forecast is assumed to account for the contribution of energy efficiency

22 The reliability requirement for an LDA is the projected internal capacity in the LDA plus the capacity emergency transfer objective (CETO) for the delivery year. The CETO is calculated to meet 1 day in 25 year loss of load expectation for an LDA. See "PJM Manual 18: PJM Capacity Market," § 2.4.2 Reliability Requirement in Locational Deliverability Areas, Rev. 47 (Jan 27, 2021). The FPR is calculated to meet 1 day in 10 year loss of load expectation for an LDA. See "PJM Manual 20: PJM Capacity Market," § 1.7 Compliance with ReliabilityFirst (RF), Rev. 10 (March 21, 2019).

resources because load is assumed to be reduced by the energy efficiency resources.[23] Consistent with the approach PJM uses in the capacity auctions, the amount of energy efficiency capacity included in the FRR plan is added back to the FRR obligation to avoid the double counting that would result from including EE as a supply side resource and as a reduction to the peak load forecast. For example, the FRR UCAP obligation for the Virginia portion of the Dominion Zone Dominion/Virginia) is defined as the Dominion/Virginia zonal forecast peak load (18,213.7 MW) times the forecast pool requirement (1.0898), or 19,849.3 MW plus the EE add back (525.1 MW) or 20,374.4 MW. The total Virginia FRR obligation including the EE add back for the 2021/2022 Delivery Year would be 21,632.7 MW.

Table 9 shows FRR UCAP obligation plus EE add back for each scenario. In Scenario 3 and Scenario 4, an FRR is established for the Virginia portion of the Dominion LSE, Virginia portion of ODEC, Northern Virginia Cooperative and Central Virginia Cooperative. The FRR service area in this scenario includes the Virginia portion of APS Zone, Virginia portion of DPL Zone and Virginia portion of Dominion LSE. The FRR UCAP obligation plus EE add back of the service area is 17,452.7 MW.

Table 8 Virginia share of the peak load, peak load forecast and FRR obligation by transmission zone[24]

Zone	Virginia Share of the Peak Load (Percent)	Zonal Peak Load Forecast (MW)	FRR UCAP Obligation (MW) plus EE add back
AEP	2.8%	306.7	336.3
APS	8.0%	710.8	778.3
Dominion	94.2%	18,213.7	20,374.4
DPL	3.5%	131.4	143.7
Virginia		19,362.6	21,632.7

23 There are significant issues with the measurement and verification of EE. See the *2019 State of the Market Report for PJM*, Volume 2, Section 6: Demand Response pg. 314.

24 The contribution percentages are the five year historical average of the Virginia portion of each zone’s load during the yearly maximum load hour.

Table 9 FRR obligation plus EE add back by Scenario[25]

Scenario	Service Area	Zones	FRR UCAP Obligation (MW) plus EE add back
1 and 2	Virginia	AEP, APS, Dominion and DPL	21,632.7
3 and 4	Dominion LSE and Cooperatives	APS, Dominion and DPL	21,296.4
5 and 6	Dominion LSE	Dominion	17,452.7
7 and 8	Dominion LSE and ODEC	APS, Dominion and DPL	19,973.3

Comparing Table 6 with Table 8 shows the zonal FRR UCAP obligations are lower than the UCAP obligations in the capacity market. The reduced obligations are a result of the fact that the RPM auction clearing uses sloped demand curves (Variable Resource Requirement or VRR curves) while the FRR Entities use vertical demand curves based on a fixed MW requirement.

Table 10 shows that the total capacity in Virginia offered in the 2021/2022 RPM BRA exceeds the Virginia FRR obligation. The surplus capacity up to the maximum allowed by an FRR entity would be offered in the PJM Capacity Market.

Table 10 shows unforced capacity offered, FRR UCAP obligation plus the EE add back and surplus in each Virginia Zone and LDA. For example, in the 2021/2022 BRA, 20,046.6 MW UCAP were offered in the Virginia portion of the Dominion Zone in the Rest of RTO LDA. The Virginia portion of the Dominion Zone FRR obligation for the 2021/2022 Delivery Year is 20,374.4 MW. The Dominion Zone has a surplus of 5,672.2 MW UCAP or 27.8 percent of the FRR UCAP obligation, not all of which could be offered in the PJM Capacity Market.

Table 11 shows the unforced capacity offered, FRR UCAP obligation plus the EE add back, surplus and unforced capacity that would be allowed to be offered in the PJM Capacity Market under the current rules for each scenario.[26] In Scenario 5 and Scenario 6, an FRR is established for the Virginia portion of the Dominion LSE. In the 2021/2022 BRA, 25,816.0 MW UCAP were offered by Dominion located in the Virginia portion of the Dominion Zone. Of the 25,816.0 MW UCAP, 19,494.3 MW UCAP is owned by Dominion. The Dominion LSE FRR obligation for the 2021/2022 Delivery Year is 17,452.7 MW. Of the remaining 2,041.6 MW UCAP owned by Dominion, only 1,300 MW UCAP would be allowed to participate in the PJM Capacity Market.[27] The total surplus, 7621.7

[25] The contribution percentages are the five year historical average of the Virginia portion of each zone's load and Wholesale Load Responsibility assigned by Dominion to the cooperatives during the yearly maximum load hour.

[26] See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.E.2.

(1,300 MW owned by Dominion and 6,321.7 MW owned by other capacity owners) would be offered in the PJM Capacity Market.

Table 10 Capacity, FRR obligation and surplus for Virginia by zone and LDA[28] [29]

Modeled LDA	Zone	Capacity (UCAP MW)	FRR Obligation (UCAP MW) plus EE add back	Surplus (UCAP MW)	Surplus (Percent)
Rest of RTO	AEP	969.2	336.3	633.0	188.2%
Rest of RTO	APS	90.1	778.3	(688.2)	(88.4%)
Rest of RTO	DOM	26,046.6	20,374.4	5,672.2	27.8%
DPL South	DPL	402.4	143.7	258.7	180.1%
Total Virginia		27,508.3	21,632.7	5,875.7	27.2%

Table 11 Self supply capacity, FRR obligation, surplus and available to offer in the PJM Capacity Market by scenario

Description	Self Supply, Demand and EE (UCAP MW)	Capacity from other Owners (UCAP MW)	FRR Obligation (UCAP MW) plus EE add back	Surplus (UCAP MW)	Available to Offer in PJM (UCAP MW)	Percent
Virginia	22,138.2	5,370.1	21,632.7	5,875.7	5,875.7	27.2%
Dominion LSE and Cooperatives	21,496.4	5,042.7	21,296.4	5,242.7	5,242.7	24.6%
Dominion LSE	19,494.3	6,321.7	17,452.7	8,363.3	7,621.7	43.7%
Dominion LSE and ODEC	21,349.7	5,085.0	19,973.3	6,461.4	6,385.0	32.0%

Table 12 shows the LDA, modeled LDA and parent LDA for each zone in Virginia. All transmission zones are LDAs, but there are also additional LDAs, including parts of zones in some cases and multiple zones in other cases. Not all LDAs are modeled separately in the PJM capacity market auctions. Of the four LDAs in Virginia, none is entirely within Virginia. AEP Zone, APS Zone and Dominion Zone are a part of Rest of RTO LDA. The Virginia portion of the DPL Zone is a part of DPL South LDA, which is a part of the EMAAC parent LDA.

27 Under the current rules, an FRR entity can sell excess capacity in RPM auctions for a delivery year subject to a cap equal to the lesser of 25 percent of the unforced capacity equivalent of the installed reserve margin for such delivery year multiplied by the preliminary forecast peak load for which such FRR entity is responsible under its FRR capacity plan(s) for such delivery year, or 1,300 MW. See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.E.2.

28 The capacity includes the annual equivalent of matched seasonal resources. Since the 2020/2021 Delivery Year, RPM rules allow seasonal resources to offer in the capacity market. Complementary seasonal capacity resources are matched within the auction clearing process.

29 The column totals exclude the FRR Obligation and shortfall for subzones to avoid double counting.

Table 12 LDA and parent LDA of zones located in Virginia

Zone	LDA	Modeled LDAs	Parent LDA
AEP	AEP	Rest of RTO	RTO
APS	APS	Rest of RTO	RTO
DOM	DOM	Rest of RTO	RTO
DPL	DPL	DPL South	RTO

Table 13 shows the weighted average net CONE times B offer caps applicable to LDAs in Virginia and the weighted average clearing prices in the 2021/2022 BRA.[30] [31]

Table 14 shows the weighted average net CONE times B offer caps and the weighted average clearing prices in the 2021/2022 BRA for each scenario.

Table 13 Net CONE times B offer cap for each zone in Virginia and weighted average clearing price for Virginia

Zone	FRR UCAP Obligation (MW) plus EE add back	Offer Cap ($ per MW-day)	Virginia Share of Zonal UCAP Obligation (MW)	2021/2022 BRA Clearing Price ($ per MW-day)
AEP	336.3	$233.91	357.1	$140.00
APS	778.3	$218.31	827.6	$140.00
DOM	20,374.4	$234.13	21,205.7	$140.00
DPL	143.7	$221.76	152.9	$165.73
Virgina	21,632.7	$233.48	22,543.4	$140.17

Table 14 Net CONE times B offer cap and weighted average clearing price for each scenario

Scenario	Description	FRR UCAP Obligation (MW) plus EE add back	Offer Cap ($ per MW-day)	Virginia Share of Zonal UCAP Obligation (MW)	2021/2022 BRA Clearing Price ($ per MW-day)
1 and 2	Virginia	21,632.7	$233.48	22,543.4	$140.17
3 and 4	Dominion LSE and Cooperatives	21,296.4	$233.47	22,186.3	$140.18
5 and 6	Dominion LSE	17,452.7	$234.13	18,164.8	$140.00
7 and 8	Dominion LSE and ODEC	19,973.3	$233.42	20,809.2	$140.19

Figure 2 is a map of the zones and modeled LDAs in Virginia.

Figure 3 is a map of LDAs in Virginia. The AEP Zone, APS Zone and Dominion Zone are not modeled LDAs and are part of the Rest of RTO LDA, which is a part of the RTO

30 Weights for offer caps are the zonal FRR UCAP obligations. Weights for clearing prices are the zonal UCAP obligations. These weights are used throughout the report when weighted average offer caps and weighted average clearing prices are calculated.

31 The net CONE times B offer caps are calculated by zone. The gross CONE values are very close across zones but net revenues vary. See Table 5 in "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> (August 24, 2018).

parent LDA. The portion of Virginia on the Delmarva Peninsula is a part of the DPL South LDA, which is a part of the parent EMAAC LDA.

Figure 4 is a map of the service territory of Dominion LSE in Virginia.

Figure 5 is a map of the service territories of member cooperatives of the Old Dominion Electric Cooperative (ODEC). The ODEC members' service area is spread across APS, Dominion and DPL Zones in Virginia.

Figure 6 is a map of the service territories of Northern Virginia Electric Cooperative and Central Virginia Electric Cooperative. Northern Virginia Electric Cooperative and Central Virginia Electric Cooperative are not members of ODEC.

Figure 2 Transmission zones in Virginia

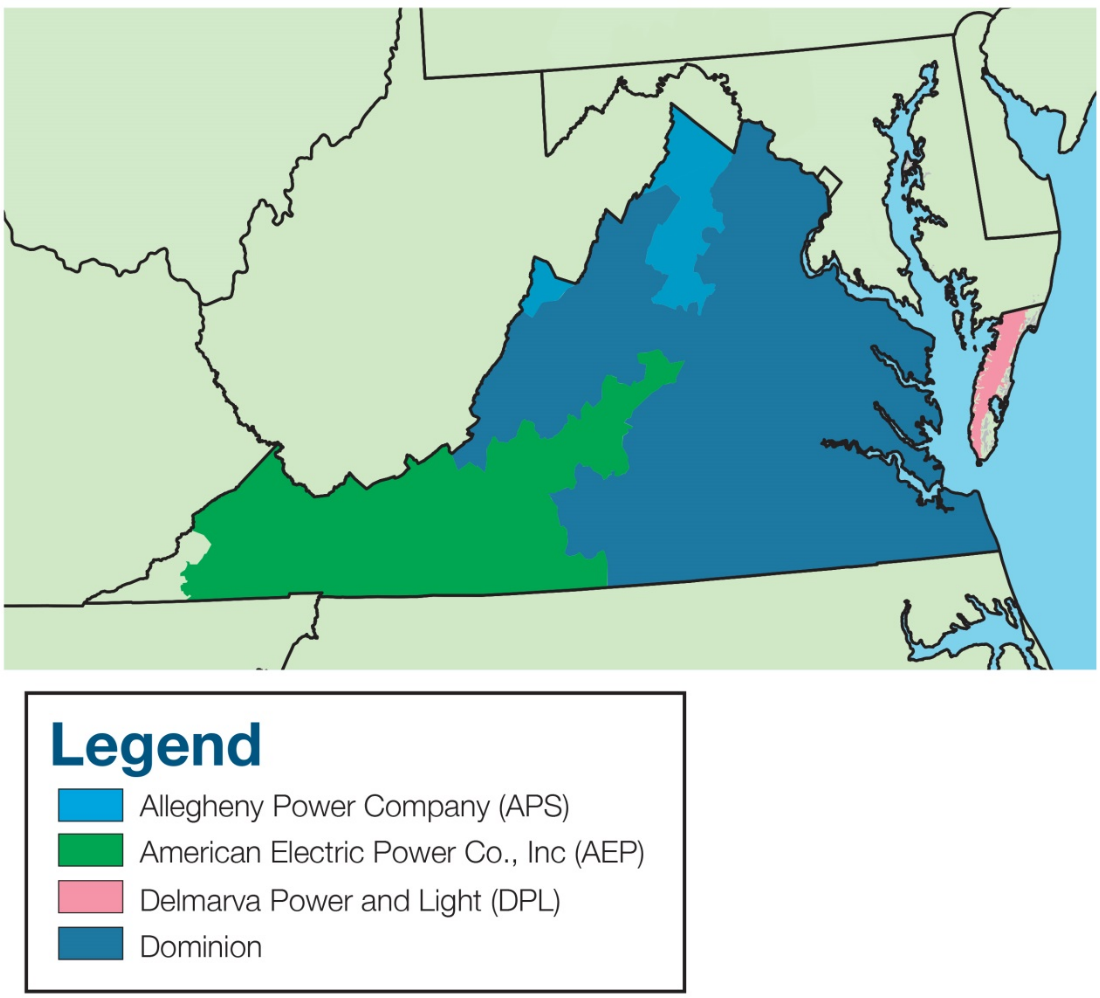


Figure 3 Modeled locational deliverability areas in Virginia

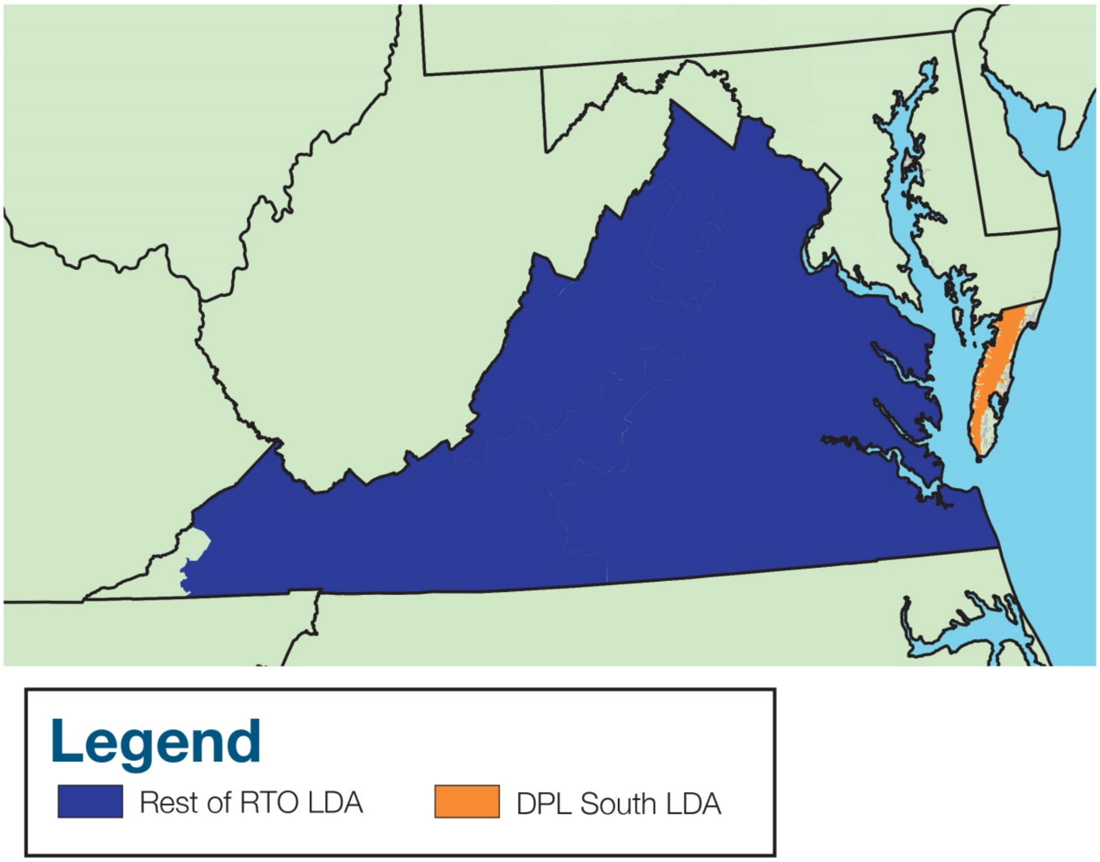
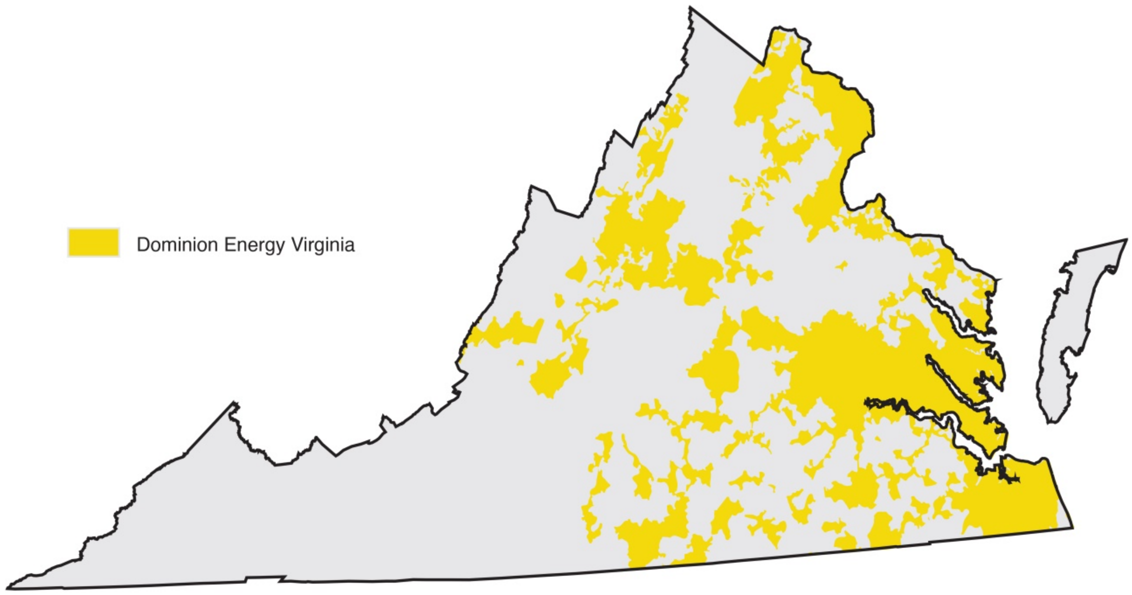
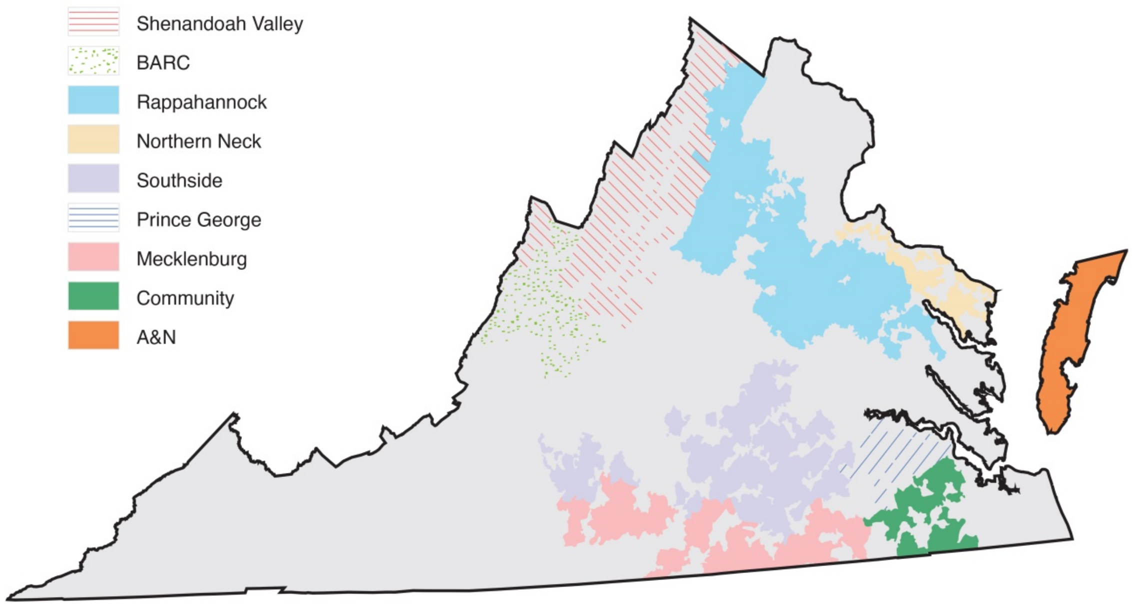


Figure 4 Service area of Dominion LSE in Virginia[32]



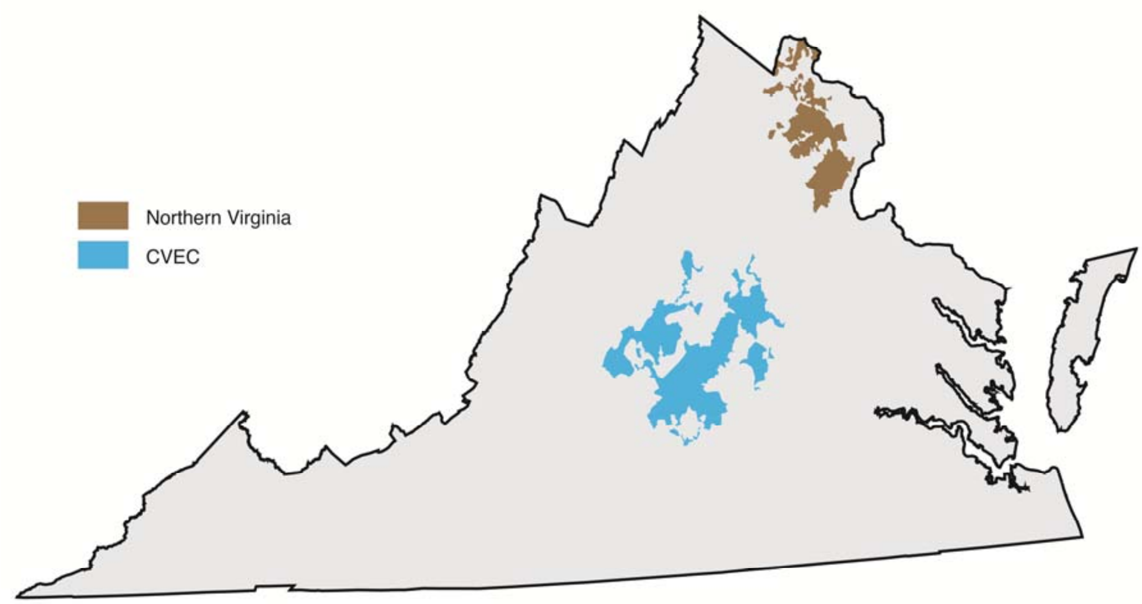
32 The service area of Dominion shown in the map was extracted from the Map of Service Territories published by the State Corporation Commission, Virginia. <https://scc.virginia.gov/pages/Regulated-Companies-Service-Map> (Accessed May 7, 2021).

Figure 5 Service area of Old Dominion Electric Cooperative in Virginia[33]



33 The service area of the Old Dominion Electric Cooperative shown in the map was extracted from the Map of Service Territories published by the State Corporation Commission, Virginia. <https://scc.virginia.gov/pages/Regulated-Companies-Service-Map> (Accessed May 7, 2021).

Figure 6 Service area of Northern Virginia Electric Cooperative and Central Virginia Electric Cooperative in Virginia[34]



Existing FRR Design

The existing FRR approach remains an option for utilities with or without retail choice, including both investor owned and publicly owned utilities.[35] [36] Such utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. There is no reason for any special exemptions for such utilities. Such utilities have the option to use the existing FRR option if they plan to continue to be cost of service based or wish to become cost of service based.

The RAA provides that states may require LSEs to become FRR entities.[37]

34 The service areas of the Northern Virginia Electric Cooperative and Central Virginia Electric Cooperative shown in the map were extracted from the Map of Service Territories published by the State Corporation Commission, Virginia. <https://scc.virginia.gov/pages/Regulated-Companies-Service-Map> (Accessed May 7, 2021).

35 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.

36 The current FRR rules address areas with retail choice. See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.D.8.

37 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.I.

The Reliability Assurance Agreement (RAA) defines the purpose of the FRR alternative.[38]

> The Fixed Resource Requirement ("FRR") Alternative provides an alternative means, under the terms and conditions of this Schedule, for an eligible Load-Serving Entity to satisfy its obligation hereunder to commit Unforced Capacity to ensure reliable service to loads in the PJM Region.

The Reliability Assurance Agreement also defines the eligibility criteria for the FRR election.[39]

> A Party is eligible to select the FRR Alternative if it (a) is an IOU, Electric Cooperative, or Public Power Entity; and (b) demonstrates the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area, including all expected load growth in such area, for the term of such Party's participation in the FRR Alternative.
>
> A Party eligible under B.1 above may select the FRR Alternative only as to all of its load in the PJM Region; provided however, that a Party may select the FRR Alternative for only part of its load in the PJM Region if (a) the Party elects the FRR Alternative for all load (including all expected load growth) in one or more FRR Service Areas; (b) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (c) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals.

An IOU is defined in the PJM RAA as "an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution."

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38 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.A.

39 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.B.

An entity must request to elect the existing FRR option no later than four months prior to the BRA. An entity must under the existing FRR option submit its FRR capacity plan no later than one month prior to the BRA for the effective delivery year. The minimum term for election of the existing FRR option is five consecutive delivery years. Under the existing FRR option, an entity may terminate its FRR election following the minimum term by providing written notice to PJM no later than two months prior to the BRA for the effective delivery year. In the event of a State Regulatory Structural Change, an entity may elect to terminate its FRR election by providing written notice to PJM no later than two months prior to the BRA for the effective delivery year.[40]

Public power entities and electric cooperatives could use the existing FRR option if they plan to continue to be cost of service based. To request the existing FRR option, public power entities or electric cooperatives need to demonstrate that the identified service area meets the definition of an FRR Service Area as defined in the RAA. The definition of FRR Service Area provides that "In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above."

Under the current rules, an FRR entity can sell excess capacity in RPM auctions for a delivery year subject to a cap equal to the lesser of 25 percent of the unforced capacity equivalent of the installed reserve margin for such delivery year multiplied by the preliminary forecast peak load for which such FRR entity is responsible under its FRR capacity plan(s) for such delivery year, or 1,300 MW.[41] For Virginia and Dominion, this

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40 State Regulatory Structural Change is defined as "to any Party, as a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable." See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

41 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.E.2.

cap would equal 1,300.0 MW. In order to sell excess capacity in RPM auctions for a delivery year, an FRR entity must commit additional capacity resources above its defined FRR UCAP obligation in an amount equal to the lesser of three percent of the FRR UCAP obligation or 450 MW.[42] For Virginia and Dominion, this additional threshold quantity would equal 450.0 MW.

Results

Load in Virginia pays a net cost of capacity that is a result of regulated cost of service rates net of the impact of the sale and purchase of capacity in the PJM Capacity Market. If load pays the market price of capacity and receives offsetting revenues equal to the market price of capacity, load is indifferent to the capacity market price and pays the regulated cost of capacity but the actual net impact on load is a result of the details of the regulatory process.

The results of each scenario should be interpreted in light of the regulatory status of the entities. The scenario results, for consistency and comparability with prior IMM FRR analyses, assume that all Virginia load paid capacity market prices for all capacity. The market prices can be used as a benchmark for whether Virginia load is paying more or less than the market value of capacity and whether Virginia load would pay more or less than the price in the identified FRR options. Scenario results should be interpreted carefully, given that Virginia load paid regulated cost of service rates for capacity that are not equal to capacity market prices and are likely to exceed capacity market prices.

For each scenario, where load currently pays regulated cost of service rates, the impact of FRR status could be zero, but the actual impact depends on the details of the regulatory process.

Scenario 1

In Scenario 1, an FRR is established that includes all of Virginia, and the FRR procures the entire Virginia FRR UCAP obligation of 21,632.7 MW at a rate equal to the weighted average of the 2021/2022 net CONE times B offer caps applicable to the LDAs in Virginia ($233.48 per MW-day).[43] Virginia has 5,875.7 MW UCAP or 27.2 percent more MW than

[42] See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1 and Schedule 8.1.E.

[43] The FRR UCAP obligation is defined as the [(obligation peak load * final zonal FRR scaling factor) – nominal PRD value committed by the FRR entity] * [forecast pool requirement + EE add back]. The final zonal FRR scaling factor equals the final zonal peak load forecast for the delivery year / zonal weather normalized peak load for the summer concluding prior to the start of the delivery year. See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.F. The EE add back MW are determined by PJM in

needed to meet its FRR obligation. If a Virginia FRR service area were created, the load in the service area would be required to procure 21,632.7 MW UCAP, 910.7 MW (4.0 percent) less than if Virginia remained in the PJM Capacity Market (Table 11). All the remaining annual resources not owned by Dominion or Cooperatives in the Virginia Zone would be assigned to the Rest of the RTO LDA, which would remain in the PJM Capacity Market. In Scenario 1, summer capacity resources in Virginia are matched with winter capacity resources in Virginia such that the total annual equivalent price is less than or equal to the weighted average of the 2021/2022 net CONE times B offer caps applicable to the LDAs in Virginia ($233.48 per MW-day). The unmatched seasonal resources are mapped to the rest of RTO LDA.

This is a sensitivity analysis based on the assumption that all the capacity resources in the Virginia FRR would be paid the same price. The actual price for capacity in the Virginia FRR would be primarily the result of a regulatory process but for independent power producers it would be the result of a negotiation between the owners of the required capacity and the relevant FRR entity or the State of Virginia. The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Table 15 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 1. All binding constraints would have remained binding and, in addition, the DEOK LDA constraint would be binding. The Rest of RTO LDA clearing price would decrease by $50.00 per MW-day from $140.00 per MW-day to $90.00 per MW-day, or 35.7 percent, from the Rest of the RTO clearing price in the 2021/2022 RPM BRA. The clearing price of EMAAC LDA would decrease by $0.73 per MW-day from $165.73 per MW-day to $165.00 per MW-day, or 0.4 percent, from the EMAAC clearing price in the 2021/2022 RPM BRA. The clearing price of the DEOK LDA would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per MW-day, or 8.2 percent, from the DEOK clearing price in the 2021/2022 RPM BRA. The clearing prices of all other constrained LDAs would remain the same.

Table 16 shows the gross and net load charges to Virginia for the 2021/2022 BRA and for Scenario 1. The net load charges when Virginia is included in the PJM Capacity Market are net of Capacity Transfer Rights (CTRs) payments to load.[44] CTRs are analogous to

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the BRA. See "PJM Manual 18B: Energy Efficiency Measurement & Verification," Rev. 04 (Aug. 22, 2019).

44 The MW of CTRs available for allocation to LSEs in an LDA is equal to the unforced capacity imported into the LDA determined based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants which include Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction and Incremental Capacity Transfer Rights (ICTRs). The price of the CTR credits is the locational adder for the LDA.

FTRs in the energy market and return capacity market congestion revenues to load. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The difference exists because load pays for all capacity at the single LDA clearing price despite the fact that the capacity imported into the LDA receives a lower price based on its location. Credits for CTRs do not exist with an FRR because the CTR credits are based on the operation of the integrated PJM Capacity Market with locational pricing. The FRR entity would no longer be in the PJM Capacity Market and the rules governing price formation in the capacity market would no longer apply.[45]

CTRs are a minor issue in Virginia because there was no price separation between Virginia LDAs and the Rest of RTO LDA, with the exception of the Virginia portion of the DPL Zone.

Table 16 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for Virginia were $1,157,790,184. In the 2021/2022 RPM BRA, only 29,288.5 MW UCAP of EMAAC LDA capacity resources cleared. The EMAAC LDA needed an additional 5,340.6 MW UCAP to meet the EMAAC LDA UCAP obligation. The CTR credits received by the EMAAC LDA are based on the UCAP MW needed to meet the EMAAC UCAP obligation. The EMAAC LDA imported 9,000.0 MW of capacity from the rest of the MAAC LDA. The clearing price for the EMAAC LDA was $25.73 per MW-day higher than the clearing price for the rest of the MAAC LDA. The load in the DPL Zone, which is part of the EMAAC LDA, received CTR credits of $5,156,858. The share of CTR credits received by the load in the Virginia portion of the DPL Zone was $180,359. The load in the other zones in Virginia did not receive any CTR credits. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Virginia were $1,157,609,825.

If a Virginia FRR were created and the capacity price for Virginia were equal to the weighted average net CONE times B offer caps applicable to the LDAs in Virginia ($233.48 per MW-day), the load charges for Virginia would have been $1,843,503,229, an increase of $685,893,404, or 59.3 percent higher than in the 2021/2022 BRA. (Table 16)

The higher load charges in Scenario 1 compared to the results of the 2021/2022 BRA are the result of higher prices, which more than offset the lower FRR UCAP obligation for the load in Virginia.

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45 If an FRR entity could pay imported capacity a lower price than it pays internal capacity, the difference would be analogous to a CTR credit. But increased reliance on internal resources in an FRR reduces the quantity of imports and the potential size of any such credit. In addition, the prices in the rest of the RTO are a function of the level of imports by the FRR entity, so if more imports are assumed, the price in the rest of RTO would also be higher.

Table 17 shows the net load charges for the RTO excluding the load in the Virginia FRR for Scenario 1. Based on actual auction clearing prices and quantities, make whole MW and the RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the Virginia FRR, were $8,557,180,988. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the RTO excluding Virginia were $8,229,234,850.

Under Scenario 1, the gross load charges for the 2021/2022 RPM BRA for the RTO excluding Virginia would have been $7,591,720,842. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for the RTO excluding Virginia, would have been $6,890,953,972, a reduction of $1,338,280,878 or 16.3 percent.

Table 15 Clearing prices in Scenario 1 and Scenario 2 compared to the actual BRA results

LDA	2021/2022 BRA	Scenario 1 and Scenario 2	Change	Percent
Rest of RTO	$140.00	$90.00	($50.00)	(35.7%)
Rest of MAAC	$140.00	$90.00	($50.00)	(35.7%)
Rest of EMAAC	$165.73	$165.00	($0.73)	(0.4%)
Rest of SWMAAC	$140.00	$90.00	($50.00)	(35.7%)
Rest of PSEG	$204.29	$204.29	$0.00	0.0%
PSEG North	$204.29	$204.29	$0.00	0.0%
DPL South	$165.73	$165.00	($0.73)	(0.4%)
Pepco	$140.00	$90.00	($50.00)	(35.7%)
Rest of ATSI	$171.33	$171.33	$0.00	0.0%
ATSI Cleveland	$171.33	$171.33	$0.00	0.0%
ComEd	$195.55	$195.55	$0.00	0.0%
BGE	$200.30	$200.30	$0.00	0.0%
PPL	$140.00	$90.00	($50.00)	(35.7%)
DAY	$140.00	$90.00	($50.00)	(35.7%)
DEOK	$140.00	$128.47	($11.53)	(8.2%)

Table 16 Net load charges for Virginia (Scenario 1)[46]

Virginia FRR	BRA	Scenario 1	Change	Percent
Zonal UCAP Obligation (MW UCAP)	22,543.4	21,632.7	(910.7)	(4.0%)
Zonal Capacity Price ($/MW-day)	$140.71	$233.48	$92.77	65.9%
Gross Load Charges	$1,157,790,184	$1,843,503,229	$685,713,045	59.2%
Value of CTRs	$180,359	$0	($180,359)	(100.0%)
Net Load Charges	$1,157,609,825	$1,843,503,229	$685,893,404	59.3%

Table 17 Net load charges for RTO excluding Virginia (Scenario 1)

RTO (Excluding Virginia)	BRA	Scenario 1 and Scenario 2	Change	Percent
Zonal UCAP Obligation	141,083.9	142,161.4	1,077.4	0.8%
Gross Load Charges	$8,557,180,988	$7,591,720,842	($965,460,146)	(11.3%)
Value of CTRs	$327,946,138	$700,766,870	$372,820,732	113.7%
Net Load Charges	$8,229,234,850	$6,890,953,972	($1,338,280,878)	(16.3%)

Scenario 2

In Scenario 2, an FRR is established that includes all of Virginia and the FRR procures the entire Virginia FRR UCAP obligation of 21,632.7 MW at a rate equal to the weighted average clearing prices in the 2021/2022 RPM BRA applicable to the LDAs in Virginia ($140.17 per MW-day). Virginia has 5,875.7 MW UCAP or 27.2 percent more MW than needed to meet its FRR obligation (Table 11). If a Virginia FRR service area were created, the load in the service area would be required to procure 21,632.7 MW UCAP, 910.7 MW (4.0 percent) less than if Virginia remained in the PJM Capacity Market. All the remaining annual resources not owned by Dominion or Cooperatives in the Virginia Zone would be assigned to the Rest of the RTO LDA, which would remain in the PJM Capacity Market. In Scenario 2, summer capacity resources in Virginia are matched with winter capacity resources in Virginia such that the total annual equivalent price is less than or equal to the weighted average clearing prices in the 2021/2022 RPM BRA applicable to the LDAs in Virginia ($140.17 per MW-day). The unmatched seasonal resources are mapped to the rest of RTO LDA.

Table 15 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 2. All binding constraints would have remained binding and, in addition, the DEOK LDA constraint would be binding. The Rest of RTO LDA clearing price would decrease by $50.00 per MW-day from $140.00 per MW-day to $90.00 per MW-day, or 35.7 percent, from the Rest of the RTO clearing price in the 2021/2022 RPM BRA. The clearing price of EMAAC LDA would decrease by $0.73 per MW-day from $165.73 per MW-day to $165.00 per MW-day, or 0.4 percent, from the

46 The net load charges for the BRA include make whole payments. The gross load charges for the delivery year are calculated using the unrounded zonal capacity price.

EMAAC clearing price in the 2021/2022 RPM BRA. The clearing price of the DEOK LDA would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA.

Table 18 shows the gross and net load charges to Virginia for the 2021/2022 BRA and for Scenario 2. The net load charges when Virginia is included in the PJM Capacity Market are net of CTRs.

Table 18 shows that, based on actual auction clearing prices and quantities, make whole MW and the RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for Virginia were $1,157,790,184. In the 2021/2022 RPM BRA, only 29,288.5 MW UCAP of EMAAC LDA capacity resources cleared. The EMAAC LDA needed an additional 5,340.6 MW UCAP to meet the EMAAC LDA UCAP obligation. The CTR credits received by the EMAAC LDA are based on the UCAP MW needed to meet the EMAAC UCAP obligation. The EMAAC LDA imported 9,000 MW of capacity from the rest of the MAAC LDA, consistent with the CETL value for EMAAC LDA. The clearing price for the EMAAC LDA was $25.73 per MW-day higher than the clearing price of the Rest of the RTO LDA. The load in the DPL Zone received CTR credits of $5,156,858. The share of CTR credits received by the load in Virginia portion of the DPL Zone was $180,359. The load in the others zones in Virginia did not receive any CTR credits. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Virginia were $1,157,609,825.

If a Virginia FRR were created and the capacity price for Virginia were equal to the weighted average of the Virginia LDAs' clearing prices in the BRA ($140.17 per MW-day), the load charges for Virginia would have been $1,106,808,060, a decrease of $50,801,765, or 4.4 percent lower than in the 2021/2022 BRA.[47]

The lower load charges in Scenario 2 compared to the results of the 2021/2022 BRA are the result of the same clearing prices and the lower FRR UCAP obligation for the load in Virginia.

Table 19 shows the net load charges for the RTO excluding the load in Virginia for Scenario 2. The net load charges for the RTO excluding Virginia are the same as Scenario 1.

[47] The $140.71 per MW-day is the Zonal UCAP Obligation weighted average net load price for Virginia, the capacity price charged to the load in the Zones within Virginia. In the 2021/2022 BRA, the Zonal UCAP Obligation, weighted resource clearing price for Virginia was $140.18 per MW-day. The difference of $0.53 per MW-day was due to Virginia's portion of funding for cleared Price Responsive Demand (PRD) credits and make whole payments to the seasonal resources.

Table 18 Net load charges for Virginia (Scenario 2)

Virginia FRR	BRA	Scenario 2	Change	Percent
Zonal UCAP Obligation	22,543.4	21,632.7	(910.7)	(4.0%)
Zonal Capacity Price ($/MW-day)	$140.71	$140.17	($0.53)	(0.4%)
Gross Load Charges	$1,157,790,184	$1,106,808,060	($50,982,124)	(4.4%)
Value of CTRs	$180,359	$0	($180,359)	(100.0%)
Net Load Charges	$1,157,609,825	$1,106,808,060	($50,801,765)	(4.4%)

Table 19 Net load charges for RTO excluding Virginia (Scenario 2)

RTO (Excluding Virginia)	BRA	Scenario 1 and Scenario 2	Change	Percent
Zonal UCAP Obligation	141,083.9	142,161.4	1,077.4	0.8%
Gross Load Charges	$8,557,180,988	$7,591,720,842	($965,460,146)	(11.3%)
Value of CTRs	$327,946,138	$700,766,870	$372,820,732	113.7%
Net Load Charges	$8,229,234,850	$6,890,953,972	($1,338,280,878)	(16.3%)

Scenario 3

In Scenario 3, an FRR is established for the Virginia portion of the Dominion LSE, Virginia portion of ODEC, Northern Virginia Electric Cooperative and Central Virginia Electric Cooperative (Dominion/Virginia and Cooperatives FRR) and the FRR procures the entire Dominion/Virginia and Cooperatives capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for the applicable LDAs in the FRR service area ($233.47 per MW-day). The Dominion/Virginia and Cooperatives FRR own 200.0 MW UCAP or 0.94 percent more MW than needed to meet their FRR obligation (Table 11). If a Dominion/Virginia and Cooperatives FRR service area were created, the Dominion/Virginia and Cooperatives FRR would be required to procure 21,296.4 MW UCAP, 889.9 MW (4.0 percent) less than if the Dominion LSE and Cooperatives remained in the PJM Capacity Market. All the remaining annual resources not owned by the Dominion/Virginia and Cooperatives and 200.0 MW UCAP owned by Dominion/Virginia and Cooperatives in Virginia would be assigned to the Rest of the RTO LDA, which would remain in the PJM Capacity Market. In Scenario 3, summer capacity resources in the Dominion/Virginia and Cooperatives service area are matched with winter capacity resources in the Dominion/Virginia and Cooperatives service area such that the total annual equivalent price is less than or equal to the 2021/2022 net CONE times B offer cap for the applicable LDAS in the Dominion/Virginia and Cooperatives ($233.47 per MW-day). The unmatched seasonal resources are mapped to the Rest of RTO LDA.

This is a sensitivity analysis based on the assumption that all the capacity resources in the Virginia FRR would be paid the same price. The actual price for capacity in the Virginia FRR would be primarily the result of a regulatory process but for independent power producers it would be the result of a negotiation between the owners of the required capacity and the relevant FRR entity or the State of Virginia. The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Table 20 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 3. All binding constraints would have remained binding and, in addition, the DEOK LDA constraint would be binding. The Rest of RTO LDA clearing price would decrease by $48.04 per MW-day from $140.00 per MW-day to $91.96 per MW-day, or 34.3 percent, from the rest of the RTO LDA clearing price in the 2021/2022 RPM BRA. The clearing price of EMAAC LDA would decrease by $0.26 per MW-day from $165.73 per MW-day to $165.47 per MW-day, or 0.2 percent, from the EMAAC clearing price in the 2021/2022 RPM BRA. The DEOK LDA clearing price would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA.

Table 21 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, load charges for the 2021/2022 RPM BRA for Dominion/Virginia and Cooperatives were $1,139,473,853. In the 2021/2022 RPM BRA, only 29,288.5 MW UCAP of EMAAC LDA capacity resources cleared. The EMAAC LDA needed an additional 5,340.6 MW UCAP to meet the EMAAC LDA UCAP obligation. The CTR credits received by the EMAAC LDA are based on the UCAP MW needed to meet the EMAAC UCAP obligation. The EMAAC LDA imported 9,000.0 MW of capacity from the rest of the MAAC LDA. The clearing price for the EMAAC LDA was $25.73 per MW-day higher than the clearing price for the rest of the MAAC LDA. The load in the DPL Zone, which is part of the EMAAC LDA, received CTR credits of $5,156,858. The share of CTR credits received by the load in the FRR portion of the DPL Zone was $180,359. The load in the other service areas in FRR did not receive any CTR credits. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Virginia were $1,139,293,494.

If a Dominion/Virginia and Cooperatives FRR were created and the capacity price for the Dominion/Virginia and Cooperatives FRR were the net CONE times B offer cap ($233.47 per MW-day), the load charges for the Dominion/Virginia and Cooperatives FRR would have been $1,814,795,021, an increase of $675,501,526, or 59.3 percent higher than in the 2021/2022 BRA.

The higher load charges in Scenario 3 compared to the results of the 2021/2022 BRA are the result of higher prices, which more than offset the lower FRR UCAP obligation for the load in Dominion/Virginia and Cooperatives.

Table 22 shows the net load charges for the RTO excluding the load in the Dominion/Virginia and Cooperatives FRR for Scenario 3. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the Dominion/Virginia and Cooperatives FRR were $8,575,497,319. After accounting for

CTRs, the net load charges for the 2021/2022 RPM BRA for the RTO excluding the Dominion/Virginia and Cooperatives FRR were $8,247,551,181.

Under Scenario 3, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the Dominion/Virginia and Cooperatives FRR would have been $7,642,517,448. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for the RTO excluding the Dominion/Virginia and Cooperatives FRR would be $6,958,080,227, a reduction of $1,289,470,953 or 15.6 percent.

Table 23 shows the net load charges for Virginia excluding the load in the Dominion/Virginia and Cooperatives FRR for Scenario 3. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for Virginia excluding the Dominion/Virginia and Cooperatives FRR were $18,316,331. The load in Virginia excluding the Dominion/Virginia and Cooperatives did not receive any CTRs.

Under Scenario 3, the gross load charges for the 2021/2022 RPM BRA, for Virginia excluding the Dominion/Virginia and Cooperatives FRR would have been $12,138,304. The load in Virginia excluding the Dominion/Virginia and Cooperatives would not receive any CTRs.

Table 24 shows the change in the net load charges for Dominion/Virginia and Cooperatives, the rest of Virginia and Virginia. Under Scenario 3, the net load charges for Dominion/Virginia and Cooperatives would increase by 59.3 percent. The net load charges for Virginia excluding the Dominion/Virginia and Cooperatives FRR would decrease by 33.7 percent. The net load charges for Virginia would increase by 57.8 percent. The net load charges for the rest of Virginia are relatively insignificant and do not meaningfully offset the increase in the net load charges for Dominion/Virginia and Cooperatives.

Table 20 Clearing prices in Scenario 3 and Scenario 4 compared to the actual BRA results

LDA	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Rest of RTO	$140.00	$91.96	($48.04)	(34.3%)
Rest of MAAC	$140.00	$91.96	($48.04)	(34.3%)
Rest of EMAAC	$165.73	$165.47	($0.26)	(0.2%)
Rest of SWMAAC	$140.00	$91.96	($48.04)	(34.3%)
Rest of PSEG	$204.29	$204.29	$0.00	0.0%
PSEG North	$204.29	$204.29	$0.00	0.0%
DPL South	$165.73	$165.47	($0.26)	(0.2%)
Pepco	$140.00	$91.96	($48.04)	(34.3%)
Rest of ATSI	$171.33	$171.33	$0.00	0.0%
ATSI Cleveland	$171.33	$171.33	$0.00	0.0%
ComEd	$195.55	$195.55	$0.00	0.0%
BGE	$200.30	$200.30	$0.00	0.0%
PPL	$140.00	$91.96	($48.04)	(34.3%)
DAY	$140.00	$91.96	($48.04)	(34.3%)
DEOK	$140.00	$128.47	($11.53)	(8.2%)

Table 21 Net load charges for Dominion/Virginia and Cooperatives (Scenario 3)

FRR	2021/2022 BRA	Scenario 3	Change	Percent
Zonal UCAP Obligation (MW UCAP)	22,186.3	21,296.4	(889.9)	(4.0%)
Zonal Capacity Price ($/MW-day)	$140.71	$233.47	$92.76	65.9%
Gross Load Charges	$1,139,473,853	$1,814,795,021	$675,321,167	59.3%
Value of CTRs	$180,359	$0	($180,359)	(100.0%)
Net Load Charges	$1,139,293,494	$1,814,795,021	$675,501,526	59.3%

Table 22 Net load charges for RTO excluding Dominion/Virginia and Cooperatives (Scenario 3)

RTO (Excluding FRR)	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	141,441.0	142,441.8	1,000.8	0.7%
Gross Load Charges	$8,575,497,319	$7,642,517,448	($932,979,870)	(10.9%)
Value of CTRs	$327,946,138	$684,437,221	$356,491,083	108.7%
Net Load Charges	$8,247,551,181	$6,958,080,227	($1,289,470,953)	(15.6%)

Table 23 Net load charges for the Rest of Virginia excluding Dominion/Virginia and Cooperatives (Scenario 3)

Virginia (Excluding FRR)	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	357.1	359.6	2.5	0.7%
Gross Load Charges	$18,316,331	$12,138,304	($6,178,027)	(33.7%)
Value of CTRs	$0	$0	$0	NA
Net Load Charges	$18,316,331	$12,138,304	($6,178,027)	(33.7%)

Table 24 Change in load charges for Dominion/Virginia and Cooperatives, Rest of Virginia and Virginia (Scenario 3)

	FRR		Rest of Virginia		Virginia	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation (MW UCAP)	(889.9)	(4.0%)	2.5	0.7%	(887.3)	(3.9%)
Gross Load Charges	$675,321,167	59.3%	($6,178,027)	(33.7%)	$669,143,141	57.8%
Value of CTRs	($180,359)	(100.0%)	$0	NA	($180,359)	(100.0%)
Net Load Charges	$675,501,526	59.3%	($6,178,027)	(33.7%)	$669,323,500	57.8%

Scenario 4

In Scenario 4, an FRR is established for the Dominion/Virginia and Cooperatives and the FRR procures the entire Dominion/Virginia and Cooperatives capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA applicable to the LDAs in the FRR service area ($140.18 per MW-day). Dominion/Virginia and Cooperatives own 200.0 MW UCAP or 0.94 percent more MW than needed to meet their FRR obligation (Table 11). If a Dominion/Virginia and Cooperatives FRR service area were created, the load in the service area would be required to procure 21,296.4 MW UCAP, 889.9 MW (4.0 percent) less than if the Dominion/Virginia and Cooperatives remained in the PJM Capacity Market. All the remaining annual resources not owned by Dominion/Virginia and Cooperatives and 200.0 MW UCAP owned by Dominion/Virginia and Cooperatives in Virginia would be assigned to the Rest of the RTO LDA, which would remain in the PJM Capacity Market. In Scenario 4, summer capacity resources in the Dominion/Virginia and Cooperatives Zone are matched with winter capacity resources in the Dominion/Virginia and Cooperatives Zone such that the total annual equivalent price is less than or equal to the clearing price in the 2021/2022 RPM BRA ($140.18 per MW-day). The unmatched seasonal resources are mapped to the Rest of RTO LDA.

Table 20 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 4. All binding constraints would have remained binding and, in addition, the DEOK LDA constraint would be binding. The Rest of RTO LDA clearing price would decrease by $48.04 per MW-day from $140.00 per MW-day to $91.96 per MW-day, or 34.3 percent, from the rest of the RTO LDA clearing price in the 2021/2022 RPM BRA. The clearing price of EMAAC LDA would decrease by $0.26 per MW-day from $165.73 per MW-day to $165.47 per MW-day, or 0.2 percent, from the EMAAC clearing price in the 2021/2022 RPM BRA. The DEOK LDA clearing price would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA.

Table 25 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for the Dominion/Virginia and Cooperatives were $1,139,473,853. In the 2021/2022 RPM BRA, only 29,288.5 MW UCAP of EMAAC LDA capacity resources cleared. The EMAAC LDA needed an additional 5,340.6 MW UCAP to meet the EMAAC LDA UCAP obligation. The CTR credits received by the EMAAC LDA are based on the UCAP MW needed to meet the EMAAC UCAP obligation. The EMAAC LDA imported 9,000.0 MW of capacity from the rest of the MAAC LDA. The clearing price for the EMAAC LDA was $25.73 per MW-day higher than the clearing price for the rest of the MAAC LDA. The load in the DPL Zone, which is part of the EMAAC LDA, received CTR credits of $5,156,858. The share of CTR credits received by the load in the Virginia portion of the DPL Zone was $180,359. The load in the other service areas in Virginia did not receive any CTR credits. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Virginia were $1,139,293,494.

If a Dominion/Virginia and Cooperatives FRR were created and the capacity price for the Dominion/Virginia and Cooperatives FRR were the clearing price in the BRA ($140.18 per MW-day), the load charges for the Dominion/Virginia and Cooperatives FRR would have been $1,089,626,015, a decrease of $49,667,480, or 4.4 percent lower than in the 2021/2022 BRA.[48]

The lower load charges in Scenario 4 compared to the results of the 2021/2022 BRA are the result of the lower FRR UCAP obligation for the load in Dominion/Virginia and Cooperatives.

Table 26 shows the net load charges, for the RTO excluding the Dominion/Virginia and Cooperatives FRR, for Scenario 4. The net load charges for the RTO excluding the Dominion/Virginia and Cooperatives FRR are the same as Scenario 3.

Table 27 shows the net load charges, for Virginia excluding the Dominion/Virginia and Cooperatives FRR, for Scenario 4. The net load charges for Virginia excluding the Dominion/Virginia and Cooperatives FRR are the same as Scenario 3.

[48] The $140.71 per MW-day is the Zonal UCAP Obligation weighted average net load price applicable for LDAs in Dominion/Virginia and Cooperatives, the capacity price charged to the load in the FRR service area within Virginia. In the 2021/2022 BRA, the Zonal UCAP Obligation, weighted resource clearing price for LDAs in Dominion/Virginia and Cooperatives, was $140.18 per MW-day. The difference of $0.53 per MW-day was due to Dominion/Virginia and Cooperatives portion of funding for cleared Price Responsive Demand (PRD) credits and make whole payments to the seasonal resources.

Table 28 shows the change in the net load charges for Dominion/Virginia and Cooperatives, the rest of Virginia and Virginia. Under Scenario 4, the net load charges for Dominion/Virginia and Cooperatives would decrease by 4.4 percent. The net load charges for Virginia excluding the Dominion/Virginia and Cooperatives FRR would decrease by 33.7 percent. The net load charges for all of Virginia would decrease by 4.8 percent. The net load charges for the rest of Virginia are relatively insignificant and do not meaningfully affect the net load charges for the Dominion/Virginia and Cooperatives.

Table 25 Net load charges for Dominion/Virginia and Cooperatives (Scenario 4)

FRR	2021/2022 BRA	Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	22,186.3	21,296.4	(889.9)	(4.0%)
Zonal Capacity Price ($/MW-day)	$140.71	$140.18	($0.53)	(0.4%)
Gross Load Charges	$1,139,473,853	$1,089,626,015	($49,847,839)	(4.4%)
Value of CTRs	$180,359	$0	($180,359)	(100.0%)
Net Load Charges	$1,139,293,494	$1,089,626,015	($49,667,480)	(4.4%)

Table 26 Net load charges for RTO excluding Dominion/Virginia and Cooperatives (Scenario 4)

RTO (Excluding FRR)	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	141,441.0	142,441.8	1,000.8	0.7%
Gross Load Charges	$8,575,497,319	$7,642,517,448	($932,979,870)	(10.9%)
Value of CTRs	$327,946,138	$684,437,221	$356,491,083	108.7%
Net Load Charges	$8,247,551,181	$6,958,080,227	($1,289,470,953)	(15.6%)

Table 27 Net load charges for the Rest of Virginia excluding Dominion/Virginia and Cooperatives (Scenario 4)

Virginia (Excluding FRR)	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	357.1	359.6	2.5	0.7%
Gross Load Charges	$18,316,331	$12,138,304	($6,178,027)	(33.7%)
Value of CTRs	$0	$0	$0	NA
Net Load Charges	$18,316,331	$12,138,304	($6,178,027)	(33.7%)

Table 28 Change in load charges for Dominion/Virginia and Cooperatives, Rest of Virginia and Virginia (Scenario 4)

	FRR		Rest of Virginia		Virginia	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation (MW UCAP)	(889.9)	(4.0%)	2.5	0.7%	(887.3)	(3.9%)
Gross Load Charges	($49,847,839)	(4.4%)	($6,178,027)	(33.7%)	($56,025,865)	(4.8%)
Value of CTRs	($180,359)	(100.0%)	$0	NA	($180,359)	(100.0%)
Net Load Charges	($49,667,480)	(4.4%)	($6,178,027)	(33.7%)	($55,845,506)	(4.8%)

Scenario 5

In Scenario 5, an FRR is established for the Virginia portion of the Dominion LSE (Dominion/Virginia) and the FRR procures the entire Dominion/Virginia capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap ($234.13 per MW-day). Dominion/Virginia own 2,041.6 MW UCAP or 11.70 percent more MW than needed to meet its FRR UCAP Obligation (Table 11). If a Dominion/Virginia FRR service area were created, the load in the service area would be required to procure 17,452.7 MW UCAP, 712.1 MW (3.9 percent) less than if the Dominion/Virginia LDA remained in the PJM Capacity Market. Of the 2,041.6 MW UCAP of excess capacity, Dominion/Virginia offers the maximum allowed 1,300 MW UCAP in the PJM Capacity Market.[49] All the remaining annual resources not owned by Dominion/Virginia and 1,300 MW UCAP owned by Dominion/Virginia would be assigned to the Rest of the RTO LDA, which would remain in the PJM Capacity Market. In Scenario 5, summer capacity resources in the Dominion/Virginia LDA are matched with winter capacity resources in the Dominion/Virginia LDA such that the total annual equivalent price is less than or equal to the 2021/2022 net CONE times B offer cap ($234.13 per MW-day). The unmatched seasonal resources are mapped to the rest of RTO LDA.

This is a sensitivity analysis based on the assumption that all the capacity resources in the Virginia FRR would be paid the same price. The actual price for capacity in the Virginia FRR would be primarily the result of a regulatory process but for independent power producers it would be the result of a negotiation between the owners of the required capacity and the relevant FRR entity or the State of Virginia. The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Table 29 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 5. All binding constraints would have remained binding and, in addition, the DEOK LDA constraint would be binding. The Rest of RTO LDA clearing price would decrease by $13.21 per MW-day from $140.00 per MW-day to $126.79 per MW-day, or 9.4 percent, from the Rest of RTO LDA clearing price in the 2021/2022 RPM BRA. The DEOK LDA clearing price would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA.

Table 30 shows the gross and net load charges to the Dominion/Virginia FRR for the 2021/2022 BRA and for Scenario 5. Dominion/Virginia is included in the Rest of RTO

[49] See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.E.2. It is assumed that the most expensive resources would be offered in the PJM capacity market.

LDA, the unconstrained area of the RTO. The load in the Rest of RTO LDA is not charged the locational adder and therefore did not receive CTR payments.

Table 30 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for the Dominion/Virginia were $931,753,397. The load in the Virginia portion of the Dominion LSE did not receive any CTR credits.

If a Dominion/Virginia FRR were created and the capacity price for the Dominion/Virginia FRR were the net CONE times B offer cap ($234.13 per MW-day), the load charges for the Dominion/Virginia FRR would have been $1,491,461,593, an increase of $559,708,197, or 60.1 percent higher than in the 2021/2022 BRA.

The higher load charges in Scenario 5 compared to the results of the 2021/2022 BRA are the result of higher prices, which more than offset the lower FRR UCAP obligation for the load in Dominion/Virginia.

Table 31 shows the net load charges for the RTO excluding the Dominion/Virginia FRR for Scenario 5. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the Dominion/Virginia FRR, were $8,783,217,775. After accounting for payments due to CTRs valued at $328,126,497, the net load charges for the 2021/2022 RPM BRA for the RTO excluding the Dominion/Virginia FRR were $8,455,091,278.

If a Dominion/Virginia FRR were created, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the Dominion/Virginia FRR would have been $8,485,283,580. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for the RTO excluding the Dominion/Virginia FRR would be $8,070,878,093, a decrease of $384,213,185 or 4.5 percent.

Table 32 shows the net load charges for Virginia excluding the load in the Dominion/Virginia FRR for Scenario 5. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for Virginia excluding the Dominion/Virginia FRR were $226,036,787. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Virginia excluding the Dominion/Virginia FRR were $225,856,428.

Under Scenario 5, the gross load charges for the 2021/2022 RPM BRA, for Virginia excluding the Dominion/Virginia FRR would have been $205,835,692. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for Virginia excluding the Dominion/Virginia FRR would be $205,561,632, a decrease of $20,294,796 or 9.0 percent.

Table 33 shows the change in the net load charges for Dominion/Virginia, the rest of Virginia and Virginia. Under Scenario 5, the net load charges for Dominion/Virginia would increase by 60.1 percent. The net load charges for Virginia excluding the Dominion/Virginia FRR would decrease by 9.0 percent. The net load charges for Virginia would increase by 46.6 percent. The reduction in load charges for the rest of Virginia due to the decrease in clearing prices in the Virginia portions of the AEP Zone, APS Zone and DPL Zone and the Virginia portion of the Dominion Zone remaining in the PJM Capacity Market partially offset the increase in the net load charges for the Dominion/Virginia Zone.

Table 29 Clearing prices in Scenario 5 compared to the actual BRA results

LDA	2021/2022 BRA	Scenario 5 and Scenario 6	Change	Percent
Rest of RTO	$140.00	$126.79	($13.21)	(9.4%)
Rest of MAAC	$140.00	$126.79	($13.21)	(9.4%)
Rest of EMAAC	$165.73	$165.73	$0.00	0.0%
Rest of SWMAAC	$140.00	$126.79	($13.21)	(9.4%)
Rest of PSEG	$204.29	$204.29	$0.00	0.0%
PSEG North	$204.29	$204.29	$0.00	0.0%
DPL South	$165.73	$165.73	$0.00	0.0%
Pepco	$140.00	$126.79	($13.21)	(9.4%)
Rest of ATSI	$171.33	$171.33	$0.00	0.0%
ATSI Cleveland	$171.33	$171.33	$0.00	0.0%
ComEd	$195.55	$195.55	$0.00	0.0%
BGE	$200.30	$200.30	$0.00	0.0%
PPL	$140.00	$126.79	($13.21)	(9.4%)
DAY	$140.00	$126.79	($13.21)	(9.4%)
DEOK	$140.00	$128.47	($11.53)	(8.2%)

Table 30 Net load charges for Dominion/Virginia LDA (Scenario 5)

Dominion LSE	2021/2022 BRA	Scenario 5	Change	Percent
Zonal UCAP Obligation (MW UCAP)	18,164.8	17,452.7	(712.1)	(3.9%)
Zonal Capacity Price ($/MW-day)	$140.53	$234.13	$93.60	66.6%
Gross Load Charges	$931,753,397	$1,491,461,593	$559,708,197	60.1%
Value of CTRs	$0	$0	$0	NA
Net Load Charges	$931,753,397	$1,491,461,593	$559,708,197	60.1%

Table 31 Net load charges for RTO excluding Dominion/Virginia LDA (Scenario 5)

RTO (Excl. Dominion LSE)	2021/2022 BRA	Scenario 5 and Scenario 6	Change	Percent
Zonal UCAP Obligation (MW UCAP)	145,462.5	145,536.4	73.8	0.1%
Gross Load Charges	$8,783,217,775	$8,485,283,580	($297,934,195)	(3.4%)
Value of CTRs	$328,126,497	$414,405,487	$86,278,990	26.3%
Net Load Charges	$8,455,091,278	$8,070,878,093	($384,213,185)	(4.5%)

Table 32 Net load charges for the Rest of Virginia (Scenario 5)

Virginia (Excl. Dominion LSE)	2021/2022 BRA	Scenario 5 and Scenario 6	Change	Percent
Zonal UCAP Obligation (MW UCAP)	4,378.6	4,380.8	2.2	0.1%
Gross Load Charges	$226,036,787	$205,835,692	($20,201,095)	(8.9%)
Value of CTRs	$180,359	$274,060	$93,701	NA
Net Load Charges	$225,856,428	$205,561,632	($20,294,796)	(9.0%)

Table 33 Change in load charges for Dominion/Virginia, Rest of Virginia and Virginia (Scenario 5)

	DOM LSE		Rest of Virginia		Virginia	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation (MW UCAP)	(712.1)	(3.9%)	2.2	0.1%	(709.9)	(3.1%)
Gross Load Charges	$559,708,197	60.1%	($20,201,095)	(8.9%)	$539,507,102	46.6%
Value of CTRs	$0	NA	$93,701	NA	$93,701	52.0%
Net Load Charges	$559,708,197	60.1%	($20,294,796)	(9.0%)	$539,413,401	46.6%

Scenario 6

In Scenario 6, an FRR is established for the Virginia portion of the Dominion LSE (Dominion/Virginia) and the FRR procures the entire Dominion/Virginia capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($140.00 per MW-day). Dominion/Virginia has 2,041.6 MW UCAP or 11.7 percent more MW than needed to meet its FRR UCAP obligation (Table 11). If a Dominion/Virginia FRR service area were created, the load in the service area would be required to procure 17,452.7 MW UCAP, 712.1 MW (3.9 percent) less than if the Dominion/Virginia LDA remained in the PJM Capacity Market. Of the 2,041.6 MW UCAP of excess capacity, Dominion offers the maximum allowed 1,300 MW UCAP in the PJM Capacity Market.[50] All the remaining annual resources not owned by the Dominion/Virginia and 1,300 MW UCAP owned by Dominion/Virginia would be assigned to the Rest of the RTO LDA, which would remain in the PJM Capacity Market. In Scenario 6, summer capacity resources in the Dominion/Virginia LDA are matched with winter capacity resources in the Dominion/Virginia LDA such that the total annual equivalent price is less than or equal to the clearing price in the 2021/2022 RPM BRA ($140.00 per MW-day). The unmatched seasonal resources are mapped to the rest of RTO LDA.

Table 29 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 6. All binding constraints would have remained binding and, in addition, the DEOK LDA constraint would also be binding. The Rest of the RTO LDA clearing price would decrease by $13.21 per MW-day from

[50] See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.E.2. It is assumed that the most expensive resources would be offered in the PJM capacity market.

$140.00 per MW-day to $126.79 per MW-day, or 9.4 percent, from the rest of the RTO LDA clearing price in the 2021/2022 RPM BRA. The DEOK LDA clearing price would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA.

Table 34 shows the gross and net load charges for the Dominion/Virginia FRR for the 2021/2022 BRA and Scenario 6. Dominion/Virginia is included in the Rest of RTO LDA, the unconstrained area of the RTO. The load in the Rest of RTO LDA is not charged the locational adder and therefore did not receive CTR payments.

Table 34 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for the Dominion/Virginia FRR were $931,753,397. The load in the Virginia portion of the Dominion LSE did not receive any CTR credits.

If a Dominion/Virginia FRR were created and the capacity price for Dominion/Virginia LDA were the clearing price in the BRA ($140.00 per MW-day), the load charges for the Dominion/Virginia FRR would have been $891,831,987, a decrease of $ $39,921,410 or 4.3 percent lower than in the 2021/2022 BRA.[51]

The lower load charges in Scenario 6 compared to the results of the 2021/2022 BRA are the result of the same clearing prices and the lower FRR UCAP obligation for the load in the Dominion/Virginia FRR area.

Table 35 shows the net load charges for the RTO excluding the Dominion/Virginia FRR for Scenario 6. The net load charges for the RTO excluding Dominion/Virginia FRR are the same as Scenario 5.

Table 36 shows the net load charges, for Virginia excluding the Dominion/Virginia FRR, for Scenario 6. The net load charges for Virginia excluding the Dominion/Virginia FRR are the same as Scenario 5.

Table 37 shows the change in the net load charges for the Dominion/Virginia FRR, the rest of Virginia and Virginia. Under Scenario 6, the net load charges for the Dominion/Virginia FRR would decrease by 4.3 percent. The net load charges for Virginia excluding the Dominion/Virginia FRR would decrease by 9.0 percent. The net load charges for Virginia would decrease by 5.2 percent. The reduction in load charges for the rest of Virginia are due to the decrease in clearing prices in the Virginia portions of AEP

51 The $140.53 per MW-day is the zone net load price, the capacity price charged to the load in the Dominion LSE. In the 2021/2022 BRA, the resource clearing price for the Dominion LSE was $140.00 per MW-day. The difference of $0.53 per MW-day was due to Dominion LSE's portion of funding for cleared Price Responsive Demand (PRD) credits and make whole payments to the seasonal resources.

Zone, APS Zone and DPL Zone and the Virginia portion of the Dominion Zone remaining in the PJM Capacity Market.

Table 34 Net load charges for Dominion/Virginia (Scenario 6)

Dominion LSE	2021/2022 BRA	Scenario 6	Change	Percent
Zonal UCAP Obligation (MW UCAP)	18,164.8	17,452.7	(712.1)	(3.9%)
Zonal Capacity Price ($/MW-day)	$140.53	$140.00	($0.53)	(0.4%)
Gross Load Charges	$931,753,397	$891,831,987	($39,921,410)	(4.3%)
Value of CTRs	$0	$0	$0	NA
Net Load Charges	$931,753,397	$891,831,987	($39,921,410)	(4.3%)

Table 35 Net load charges for RTO excluding Dominion/Virginia (Scenario 6)

RTO (Excl. Dominion LSE)	2021/2022 BRA	Scenario 5 and Scenario 6	Change	Percent
Zonal UCAP Obligation (MW UCAP)	145,462.5	145,536.4	73.8	0.1%
Gross Load Charges	$8,783,217,775	$8,485,283,580	($297,934,195)	(3.4%)
Value of CTRs	$328,126,497	$414,405,487	$86,278,990	26.3%
Net Load Charges	$8,455,091,278	$8,070,878,093	($384,213,185)	(4.5%)

Table 36 Net load charges for the Rest of Virginia (Scenario 6)

Virginia (Excl. Dominion LSE)	2021/2022 BRA	Scenario 5 and Scenario 6	Change	Percent
Zonal UCAP Obligation (MW UCAP)	4,378.6	4,380.8	2.2	0.1%
Gross Load Charges	$226,036,787	$205,835,692	($20,201,095)	(8.9%)
Value of CTRs	$180,359	$274,060	$93,701	NA
Net Load Charges	$225,856,428	$205,561,632	($20,294,796)	(9.0%)

Table 37 Change in load charges for Dominion/Virginia, Rest of Virginia and Virginia (Scenario 6)

	DOM LSE		Rest of Virginia		Virginia	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation (MW UCAP)	(712.1)	(3.9%)	2.2	0.1%	(709.9)	(3.1%)
Gross Load Charges	($39,921,410)	(4.3%)	($20,201,095)	(8.9%)	($60,122,505)	(5.2%)
Value of CTRs	$0	NA	$93,701	NA	$93,701	52.0%
Net Load Charges	($39,921,410)	(4.3%)	($20,294,796)	(9.0%)	($60,216,206)	(5.2%)

Scenario 7

In Scenario 7, an FRR is established for the Virginia portion of the Dominion LSE and the Virginia portion of ODEC (Dominion/Virginia and ODEC FRR), and the FRR procures the entire Dominion/Virginia and ODEC capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for the applicable LDAs in the FRR service area ($233.42 per MW-day). The Dominion/Virginia and ODEC FRR own 1,376.4 MW UCAP or 6.9 percent more MW than needed to meet their FRR obligation (Table 11). If a Dominion/Virginia and ODEC FRR service area were created, the Dominion/Virginia and ODEC FRR would be required to procure 19,973.3 MW UCAP, 835.9 MW (4.0

percent) less than if the Dominion LSE and ODEC remained in the PJM Capacity Market. Of the 1,376.4 MW UCAP of excess capacity, Dominion/Virginia and ODEC offer the maximum allowed 1,300 MW UCAP in the PJM Capacity Market.[52] All the remaining annual resources not owned by the Dominion/Virginia and ODEC and 1,300 MW UCAP owned by Dominion/Virginia and ODEC would be assigned to the Rest of the RTO LDA, which would remain in the PJM Capacity Market. In Scenario 7, summer capacity resources in the Dominion/Virginia and ODEC service area are matched with winter capacity resources in the Dominion/Virginia and ODEC service area such that the total annual equivalent price is less than or equal to the 2021/2022 net CONE times B offer cap for the applicable LDAs in the Dominion/Virginia and ODEC ($233.42 per MW-day). The unmatched seasonal resources are mapped to the Rest of RTO LDA.

This is a sensitivity analysis based on the assumption that all the capacity resources in the Virginia FRR would be paid the same price. The actual price for capacity in the Virginia FRR would be primarily the result of a regulatory process but for independent power producers it would be the result of a negotiation between the owners of the required capacity and the relevant FRR entity or the State of Virginia. The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Table 38 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 7. All binding constraints would have remained binding and, in addition, the DEOK LDA constraint would be binding. The Rest of RTO LDA clearing price would decrease by $30.05 per MW-day from $140.00 per MW-day to $109.95 per MW-day, or 21.5 percent, from the rest of the RTO LDA clearing price in the 2021/2022 RPM BRA. The clearing price of EMAAC LDA would decrease by $0.26 per MW-day from $165.73 per MW-day to $165.47 per MW-day, or 0.2 percent, from the EMAAC clearing price in the 2021/2022 RPM BRA. The DEOK LDA clearing price would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA.

Table 39 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, load charges for the 2021/2022 RPM BRA for Dominion/Virginia and ODEC were $1,068,837,885. In the 2021/2022 RPM BRA, only 29,288.5 MW UCAP of EMAAC LDA capacity resources cleared. The EMAAC LDA needed an additional 5,340.6 MW UCAP to meet the EMAAC LDA UCAP obligation. The CTR credits received by the EMAAC LDA are based on the UCAP MW needed to meet the EMAAC UCAP obligation. The EMAAC LDA imported 9,000.0 MW of capacity

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52 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.E.2. It is assumed that the most expensive resources would be offered in the PJM capacity market.

from the rest of the MAAC LDA. The clearing price for the EMAAC LDA was $25.73 per MW-day higher than the clearing price for the rest of the MAAC LDA. The load in the DPL Zone, which is part of the EMAAC LDA, received CTR credits of $5,156,858. The share of CTR credits received by the load in the FRR portion of the DPL Zone was $180,359. The load in the other service areas in FRR did not receive any CTR credits. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Virginia were $1,068,657,526.

If a Dominion/Virginia and ODEC FRR were created and the capacity price for the Dominion/Virginia and ODEC FRR were the net CONE times B offer cap ($233.42 per MW-day), the load charges for the Dominion/Virginia and ODEC FRR would have been $1,701,727,729, an increase of $633,070,202, or 59.2 percent higher than in the 2021/2022 BRA.

The higher load charges in Scenario 7 compared to the results of the 2021/2022 BRA are the result of higher prices, which more than offset the lower FRR UCAP obligation for the load in Dominion/Virginia and ODEC.

Table 40 shows the net load charges for the RTO excluding the Dominion/Virginia and ODEC FRR for Scenario 7. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the Dominion/Virginia and ODEC FRR were $8,646,133,287. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the RTO excluding the Dominion/Virginia and ODEC FRR were $8,318,187,149.

Under Scenario 7, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the Dominion/Virginia and ODEC FRR would have been $8,037,015,564. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for the RTO excluding the Dominion/Virginia and ODEC FRR would be $7,494,020,501, a reduction of $824,166,648 or 9.9 percent.

Table 41 shows the net load charges for Virginia excluding the Dominion/Virginia and ODEC FRR for Scenario 7. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for Virginia excluding the Dominion/Virginia and ODEC FRR were $88,952,299. The load in Virginia excluding the Dominion/Virginia and ODEC did not receive any CTRs.

Under Scenario 7, the gross load charges for the 2021/2022 RPM BRA, for Virginia excluding the Dominion/Virginia and ODEC FRR would have been $70,209,144. The load in Virginia excluding the Dominion/Virginia and ODEC would not receive any CTRs.

Table 42 shows the change in the net load charges for Dominion/Virginia and ODEC, the rest of Virginia and Virginia. Under Scenario 7, the net load charges for Dominion/Virginia and ODEC would increase by 59.2 percent. The net load charges for

Virginia excluding the Dominion/Virginia and ODEC FRR would decrease by 21.1 percent. The net load charges for Virginia would increase by 53.1 percent. The net load charges for the rest of Virginia were too small to meaningfully offset the increase in the net load charges for Dominion/Virginia and ODEC.

Table 38 Clearing prices in Scenario 7 and Scenario 8 compared to the actual BRA results

LDA	2021/2022 BRA	Scenario 7 and Scenario 8	Change	Percent
Rest of RTO	$140.00	$109.95	($30.05)	(21.5%)
Rest of MAAC	$140.00	$109.95	($30.05)	(21.5%)
Rest of EMAAC	$165.73	$165.47	($0.26)	(0.2%)
Rest of SWMAAC	$140.00	$109.95	($30.05)	(21.5%)
Rest of PSEG	$204.29	$204.29	$0.00	0.0%
PSEG North	$204.29	$204.29	$0.00	0.0%
DPL South	$165.73	$165.47	($0.26)	(0.2%)
Pepco	$140.00	$109.95	($30.05)	(21.5%)
Rest of ATSI	$171.33	$171.33	$0.00	0.0%
ATSI Cleveland	$171.33	$171.33	$0.00	0.0%
ComEd	$195.55	$195.55	$0.00	0.0%
BGE	$200.30	$200.30	$0.00	0.0%
PPL	$140.00	$109.95	($30.05)	(21.5%)
DAY	$140.00	$109.95	($30.05)	(21.5%)
DEOK	$140.00	$128.47	($11.53)	(8.2%)

Table 39 Net load charges for Dominion/Virginia and ODEC (Scenario 7)

Dominion LSE and ODEC	2021/2022 BRA	Scenario 7	Change	Percent
Zonal UCAP Obligation (MW UCAP)	20,809.2	19,973.3	(835.9)	(4.0%)
Zonal Capacity Price ($/MW-day)	$140.72	$233.42	$92.70	65.9%
Gross Load Charges	$1,068,837,885	$1,701,727,729	$632,889,843	59.2%
Value of CTRs	$180,359	$0	($180,359)	(100.0%)
Net Load Charges	$1,068,657,526	$1,701,727,729	$633,070,202	59.2%

Table 40 Net load charges for RTO excluding Dominion/Virginia and ODEC (Scenario 7)

RTO (Excl. DOM LSE and ODEC)	2021/2022 BRA	Scenario 7 and Scenario 8	Change	Percent
Zonal UCAP Obligation (MW UCAP)	142,818.1	143,346.3	528.2	0.4%
Gross Load Charges	$8,646,133,287	$8,037,015,564	($609,117,723)	(7.0%)
Value of CTRs	$327,946,138	$542,995,063	$215,048,925	65.6%
Net Load Charges	$8,318,187,149	$7,494,020,501	($824,166,648)	(9.9%)

Table 41 Net load charges for the Rest of Virginia excluding Dominion/Virginia and ODEC (Scenario 7)

Virginia (Excl. DOM LSE and ODEC)	2021/2022 BRA	Scenario 7 and Scenario 8	Change	Percent
Zonal UCAP Obligation (MW UCAP)	1,734.1	1,740.6	6.5	0.4%
Gross Load Charges	$88,952,299	$70,209,144	($18,743,155)	(21.1%)
Value of CTRs	$0	$0	$0	NA
Net Load Charges	$88,952,299	$70,209,144	($18,743,155)	(21.1%)

Table 42 Change in load charges for Dominion/Virginia and ODEC, Rest of Virginia and Virginia (Scenario 7)

	FRR		Rest of Virginia		Virginia	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation (MW UCAP)	(835.9)	(4.0%)	6.5	0.4%	(829.4)	(3.7%)
Gross Load Charges	$632,889,843	59.2%	($18,743,155)	(21.1%)	$614,146,688	53.0%
Value of CTRs	($180,359)	(100.0%)	$0	NA	($180,359)	(100.0%)
Net Load Charges	$633,070,202	59.2%	($18,743,155)	(21.1%)	$614,327,047	53.1%

Scenario 8

In Scenario 8, an FRR is established for the Virginia portion of the Dominion LSE and the Virginia portion of ODEC (Dominion/Virginia and ODEC FRR), and the FRR procures the entire Dominion/Virginia and ODEC capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA applicable to the LDAs in the FRR service area ($140.19 per MW-day). Dominion/Virginia and ODEC own 1,376.4 MW UCAP or 6.9 percent more MW than needed to meet their FRR obligation (Table 11). If a Dominion/Virginia and ODEC FRR service area were created, the load in the service area would be required to procure 19,973.3 MW UCAP, 835.9 MW (4.0 percent) less than if the Dominion/Virginia and ODEC remained in the PJM Capacity Market. Of the 1,376.4 MW UCAP of excess capacity, Dominion/Virginia and ODEC offer the maximum allowed 1,300 MW UCAP in the PJM Capacity Market.[53] All the remaining annual resources not owned by Dominion/Virginia and ODEC and 1,300 MW UCAP owned by Dominion/Virginia and ODEC in Virginia would be assigned to the Rest of the RTO LDA, which would remain in the PJM Capacity Market. In Scenario 8, summer capacity resources in the Dominion/Virginia and ODEC Zone are matched with winter capacity resources in the Dominion/Virginia and ODEC Zone such that the total annual equivalent price is less than or equal to the clearing price in the 2021/2022 RPM BRA ($140.19 per MW-day). The unmatched seasonal resources are mapped to the Rest of RTO LDA.

[53] See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.E.2. It is assumed that the most expensive resources would be offered in the PJM Capacity Market.

Table 38 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 8. All binding constraints would have remained binding and, in addition, the DEOK LDA constraint would be binding. The Rest of RTO LDA clearing price would decrease by $30.05 per MW-day from $140.00 per MW-day to $109.95 per MW-day, or 21.5 percent, from the rest of the RTO LDA clearing price in the 2021/2022 RPM BRA. The clearing price of EMAAC LDA would decrease by $0.26 per MW-day from $165.73 per MW-day to $165.47 per MW-day, or 0.2 percent, from the EMAAC clearing price in the 2021/2022 RPM BRA. The DEOK LDA clearing price would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA.

Table 43 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for the Dominion/Virginia and ODEC were $1,068,837,885. In the 2021/2022 RPM BRA, only 29,288.5 MW UCAP of EMAAC LDA capacity resources cleared. The EMAAC LDA needed an additional 5,340.6 MW UCAP to meet the EMAAC LDA UCAP obligation. The CTR credits received by the EMAAC LDA are based on the UCAP MW needed to meet the EMAAC UCAP obligation. The EMAAC LDA imported 9,000.0 MW of capacity from the rest of the MAAC LDA. The clearing price for the EMAAC LDA was $25.73 per MW-day higher than the clearing price for the rest of the MAAC LDA. The load in the DPL Zone, which is part of the EMAAC LDA, received CTR credits of $5,156,858. The share of CTR credits received by the load in the FRR portion of the DPL Zone was $180,359. The load in the other service areas in FRR did not receive any CTR credits. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Virginia were $1,068,657,526.

If a Dominion/Virginia and ODEC FRR were created and the capacity price for the Dominion/Virginia and ODEC FRR were the clearing price in the BRA ($140.19 per MW-day), the load charges for the Dominion/Virginia and ODEC FRR would have been $1,022,016,392, a decrease of $46,641,135, or 4.4 percent lower than in the 2021/2022 BRA.[54]

The lower load charges in Scenario 8 compared to the results of the 2021/2022 BRA are the result of the lower FRR UCAP obligation for the load in Dominion/Virginia and ODEC.

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54 The $140.72 per MW-day is the Zonal UCAP Obligation weighted average net load price applicable for LDAs in Dominion/Virginia and Cooperatives, the capacity price charged to the load in the FRR service area within Virginia. In the 2021/2022 BRA, the Zonal UCAP Obligation, weighted resource clearing price for LDAs in Dominion/Virginia and Cooperatives, was $140.19 per MW-day. The difference of $0.53 per MW-day was due to Dominion/Virginia and Cooperatives portion of funding for cleared Price Responsive Demand (PRD) credits and make whole payments to the seasonal resources.

Table 44 shows the net load charges, for the RTO excluding the Dominion/Virginia and ODEC FRR, for Scenario 8. The net load charges for the RTO excluding the Dominion/Virginia and ODEC FRR are the same as Scenario 7.

Table 45 shows the net load charges, for Virginia excluding the Dominion/Virginia and ODEC FRR, for Scenario 8. The net load charges for Virginia excluding the Dominion/Virginia and ODEC FRR are the same as Scenario 7.

Table 46 shows the change in the net load charges for Dominion/Virginia and ODEC, the rest of Virginia and Virginia. Under Scenario 8, the net load charges for Dominion/Virginia and ODEC would decrease by 4.4 percent. The net load charges for Virginia excluding the Dominion/Virginia and ODEC FRR would decrease by 21.1 percent. The net load charges for all of Virginia would decrease by 5.6 percent. The reduction in load charges for the rest of Virginia is due to the decrease in clearing prices in the Virginia portions of AEP Zone and APS Zone, which includes the service territories of cooperatives not owned by ODEC, added to the decrease in the net load charges for the Dominion/Virginia and ODEC FRR.

Table 43 Net load charges for Dominion/Virginia and ODEC (Scenario 8)

Dominion LSE and ODEC	2021/2022 BRA	Scenario 8	Change	Percent
Zonal UCAP Obligation (MW UCAP)	20,809.2	19,973.3	(835.9)	(4.0%)
Zonal Capacity Price ($/MW-day)	$140.72	$140.19	($0.53)	(0.4%)
Gross Load Charges	$1,068,837,885	$1,022,016,392	($46,821,494)	(4.4%)
Value of CTRs	$180,359	$0	($180,359)	(100.0%)
Net Load Charges	$1,068,657,526	$1,022,016,392	($46,641,135)	(4.4%)

Table 44 Net load charges for RTO excluding Dominion/Virginia and ODEC (Scenario 8)

RTO (Excl. DOM LSE and ODEC)	2021/2022 BRA	Scenario 7 and Scenario 8	Change	Percent
Zonal UCAP Obligation (MW UCAP)	142,818.1	143,346.3	528.2	0.4%
Gross Load Charges	$8,646,133,287	$8,037,015,564	($609,117,723)	(7.0%)
Value of CTRs	$327,946,138	$542,995,063	$215,048,925	65.6%
Net Load Charges	$8,318,187,149	$7,494,020,501	($824,166,648)	(9.9%)

Table 45 Net load charges for the Rest of Virginia excluding Dominion/Virginia and ODEC (Scenario 8)

Virginia (Excl. DOM LSE and ODEC)	2021/2022 BRA	Scenario 7 and Scenario 8	Change	Percent
Zonal UCAP Obligation (MW UCAP)	1,734.1	1,740.6	6.5	0.4%
Gross Load Charges	$88,952,299	$70,209,144	($18,743,155)	(21.1%)
Value of CTRs	$0	$0	$0	NA
Net Load Charges	$88,952,299	$70,209,144	($18,743,155)	(21.1%)

Table 46 Change in load charges for Dominion/Virginia and ODEC, Rest of Virginia and Virginia (Scenario 8)

	FRR		Rest of Virginia		Virginia	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation (MW UCAP)	(835.9)	(4.0%)	6.5	0.4%	(829.4)	(3.7%)
Gross Load Charges	($46,821,494)	(4.4%)	($18,743,155)	(21.1%)	($65,564,649)	(5.7%)
Value of CTRs	($180,359)	(100.0%)	$0	NA	($180,359)	(100.0%)
Net Load Charges	($46,641,135)	(4.4%)	($18,743,155)	(21.1%)	($65,384,290)	(5.6%)