Potential Impacts of the Creation of District of Columbia FRR

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 the District of Columbia (DC). 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 DC would need to meet their FRR capacity obligation through owned capacity, if any, and bilateral contracts with the owners of capacity, primarily within the Pepco Zone but also including resources from outside Pepco Zone. The IMM analyzed two scenarios.

The entire DC region is within the Pepco Zone. The rest of the Pepco Zone is located in Maryland. The Pepco Zone includes the Pepco LDA but is not identical to the Pepco LDA, which is a part of the SWMAAC parent LDA.

In Scenario 1, the IMM assumes that an FRR is established that includes all of the DC portion of the Pepco LDA (Pepco/DC FRR) and that the Pepco/DC FRR procures the entire Pepco/DC capacity obligation at a rate equal to the net Cost of New Entry (CONE) times B offer cap applicable to the Pepco LDA ($210.86 per MW-day) for the 2021/2022 PJM Reliability Pricing Model (RPM) Base Residual Auction (BRA). The rest of the Pepco LDA remains in the PJM Capacity Market. The IMM concludes that under Scenario 1, net load charges for Pepco/DC FRR under the FRR alternative would increase by $46.5 million or 41.3 percent compared to the results of the 2021/2022 RPM BRA.

In Scenario 2, the IMM assumes that an FRR is established that includes all of Pepco/DC and that the Pepco/DC FRR procures the entire Pepco/DC capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA applicable to the Pepco LDA ($140.00 per MW-day). The IMM concludes that under Scenario 2, the net load charges for Pepco/DC under the FRR alternative would decrease by $6.9 million or 6.2 percent compared to the results of the 2021/2022 RPM BRA.

For both Scenarios 1 and 2, the IMM also analyzed the impacts on the RTO, excluding the Pepco/DC FRR. In both scenarios, the clearing prices in the Rest of RTO would remain unchanged. Net load charges for the RTO excluding Pepco/DC FRR would be higher by $1.9 million, or less than 0.1 percent compared to the 2021/2022 RPM BRA net load charges.

Table 1 presents a summary of the results for two scenarios including the impact on net load charges for the defined FRRs, and for the rest of the PJM market.

Table 1 Scenario summary

	FRR		Rest of PJM Market	
Scenario	Change	Percent	Change	Percent
1	$46,467,477	41.3%	$1,901,343	0.0%
2	($6,919,804)	(6.2%)	$1,901,343	0.0%

Based on the analysis, the creation of a Pepco/DC FRR is likely to increase payments for capacity by customers in DC. It is expected that the actual price for capacity in DC would be the result of a negotiation between the owners of the required capacity, and the District of Columbia.[1] The resultant price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Creation of an FRR creates market power for the small number of generation owners from whom generation must be purchased in order to meet the reliability requirements of the FRR entities. All participants in the Pepco FRR fail the three pivotal supplier test which reinforces the conclusion that there is structural market power in each case. A fundamental point about the FRR approach is that the FRR approach is a nonmarket approach. In the FRR approach, there is no PJM market monitoring of offer behavior by generation owners, there are no market rules governing offers, and there are no market rules requiring competitive behavior. In the absence of a competitive market that includes the FRR area(s), there is no competitive market reference point to define what a competitive offer would be from the FRR generation owners in a bilateral negotiation or what the competitive market price would be. Prior market results do not define a competitive outcome in subsequent periods because market dynamics and market outcomes may change significantly. As a result, even the higher estimates of the cost impact to the customers of DC from the creation of an FRR are likely to be conservatively low. If DC were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

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 Pepco/DC FRR service area both on payments by customers in DC and by customers in the balance of the RTO, based on explicitly stated assumptions.[2] The IMM previously published reports on the impacts of a ComEd FRR, a set of Maryland FRRs, a set of New Jersey FRRs and a set of Ohio FRRs, but the public discussion of potential FRRs in other LDAs has not been supported by analysis to date.[3] [4] [5] [6] The IMM will provide analyses of

1 This could also include the owners of capacity that could be imported, limited by the CETL.

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

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

4 "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).

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.

DC is entirely located within the Pepco Zone. The Pepco Zone includes both DC and part of Maryland. DC could require that the entire portion of the Pepco Zone located in DC elect FRR status. 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. In DC, there are not enough capacity resources to meet the PJM defined FRR UCAP obligation. In order to create a viable Pepco/DC FRR, load in DC would need to contract with other capacity resource owners inside and outside DC,

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5 "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).

6 "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).

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.

limited by Capacity Emergency Transfer Limit (CETL) and minimum internal resource requirement, to meet the FRR UCAP obligation for the load in DC.[10]

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 Pepco/DC FRR service area for load in DC, and for the rest of the capacity market, under two scenarios:

- Scenario 1: An FRR is established that includes Pepco/DC and the Pepco/DC FRR procures the Pepco/DC capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap applicable to the Pepco LDA ($210.86 per MW-day).
- Scenario 2: An FRR is established that includes Pepco/DC and the Pepco/DC FRR procures the Pepco/DC capacity obligation at a rate equal to the clearing prices in the 2021/2022 RPM BRA applicable to the Pepco LDA ($140.00 per MW-day).

Assumptions

1. In Scenarios 1 and 2, the PJM Capacity Market would not include DC.
2. There would be capacity imports into the Pepco/DC FRR from capacity resources needed to cover any shortfall in meeting the FRR obligation. The price of imports to DC from capacity resources outside DC is assumed to be the same as the price paid to the capacity resources in DC meeting the FRR obligation.
3. 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.
4. Unmatched seasonal resources would offer their capacity in the PJM Capacity Market. These resources would be mapped to the relevant parent LDA.
5. All resources that do not enter a contract with a Pepco/DC FRR would offer their capacity resources in the PJM Capacity Market.

[10] The minimum internal resource requirement is the minimum percentage of capacity resources that must be located within an LDA to satisfy an FRR plan. It is calculated as the LDA reliability requirement minus CETL, divided by the zonal peak load forecast times the forecast pool wide requirement for the delivery year. In the 2021/2022 RPM BRA, Pepco LDA did not have defined minimum internal resource requirement.

[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).

6. 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

There were no generation capacity resources in DC offered in the 2021/2022 RPM BRA.

Table 2 shows the installed capacity by fuel source for the capacity resources located in DC.[13]

Table 2 Installed capacity offered in 2021/2022 RPM BRA by fuel source[14] [15]

Modeled LDA	Zone	Coal	Gas	Nuclear	Oil	Solar	Solid Waste	Hydroelectric	Wind	DR	EE	PRD	Total
Pepco/DC	Pepco	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	65.1	12.0	0.0	77.1
Total DC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	65.1	12.0	0.0	77.1

DC's renewable portfolio standard (RPS) has a target of 100 percent from Tier 1 renewable energy sources by 2032.[16] The standard includes an additional requirement that 10 percent of that energy must be sourced from solar energy generated within the

[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.

[15] The precise geographical location of demand resources and energy efficiency resources offered in the 2021/2022 RPM BRA is not available. The demand resources and energy efficiency resources offered in the Pepco zone are allocated to DC based on the five year historical average share of the DC portion of Pepco zone's load during the yearly maximum load hour.

[16] DC's RPS definition is not zero carbon. DC's RPS definition of Tier I renewable resources includes wind, solar, waste to energy, geothermal, energy from waves tides and currents, and landfill gas technologies. Waste to energy, geothermal, and landfill gas energy production result in carbon emissions.

District by 2041.[17] The total RPS percent for 2021 is 26.25 percent with 2.5 percent required to be from solar resources within the district.

The most recent data from DC shows that energy production from DC resources meeting the Tier I RPS standard was 168.8 GWh in 2020.[18] In 2019, energy production from DC resources meeting the Tier I RPS standard was 124.9 GWh.[19] DC also imports significant levels of energy in order to meet RPS targets. In the 2020 compliance year, DC imported 96.7 percent of the total RECs that met Tier I RPS standards; 80.1 percent of the imported Tier I RECs were from renewable energy resources.[20]

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; and highly concentrated if the market HHI is greater than 1800, equivalent to between five and six firms with equal market shares.[21]

Table 3 shows the HHI results for the FRR analyzed. The HHI results show that the Pepco FRR is highly concentrated.

Table 3 HHI results

Market	HHI
Pepco	5457

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

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17 See Clean Energy DC Omnibus Amendment Act of 2018 (March 22, 2019) <http://lims.dccouncil.us/Download/40667/B22-0904-SignedAct.pdf>.

18 Tier I resources include carbon emitting resources. Solar generation accounted for 64.4 percent of the Tier I generation in 2020 and 35.6 percent was generated by carbon producing technologies.

19 Solar generation accounted for 58.4 percent of the Tier I generation in 2019 and 41.6 percent was generated by carbon producing technologies.

20 PJM EIS GATS.

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

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 4 shows the results of the pivotal supplier test for the FRRs analyzed. All participants in the Pepco FRR fail the three pivotal supplier test (RSI is less than 1.0).[22]

Table 4 Pivotal supplier results

Market	RSI_1	RSI_3	Total Participants	Failed RSI_3 Participants
Pepco	0.34	0.08	6	6

Table 5 shows zonal UCAP obligation for the DC portion of the Pepco Zone. This is the capacity obligation assigned to DC. The zonal UCAP obligation for the entire Pepco Zone is 7,116.0 MW. DC's share of the Pepco Zone zonal UCAP obligation is 2,191.2 MW. The total DC zonal UCAP obligation for 2021/2022 Delivery Year is 2,191.2 MW.[23]

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

23 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. 43 (Dec. 3, 2019). 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).

Table 5 DC share of the zonal UCAP obligation by transmission zone

Zone	DC Share of the Peak Load (Percent)	Zonal UCAP Obligation (MW)	DC Share of Zonal UCAP Obligation (MW)
Pepco	30.8%	7,116.0	2,191.2
DC		7,116.0	2,191.2

Table 6 shows the FRR UCAP MW obligation for Pepco/DC FRR. This is the capacity obligation that would be assigned to DC if DC 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 resources because load is assumed to be reduced by the energy efficiency resources.[24] 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. The FRR UCAP obligation for Pepco/DC is defined as the Pepco/DC zonal forecast peak load (1,882.1 MW) times the forecast pool requirement (1.0898), or 2,051.1 MW plus the EE add back (13.1 MW) or 2,064.2 MW. The total Pepco/DC FRR obligation including the EE add back for the 2021/2022 Delivery Year is 2,064.2 MW.

Table 6 DC share of the peak load, peak load forecast and FRR obligation by transmission zone[25]

Zone	DC Share of the Peak Load (Percent)	Zonal Peak Load Forecast (MW)	FRR UCAP Obligation (MW) plus EE add back
Pepco	30.8%	1,882.1	2,064.2
Total		1,882.1	2,064.2

Comparing Table 5 with Table 6 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. Under the current rules for every LDA, the calculated reliability requirement reflects the more stringent 1 day in 25 years loss of load expectation. The calculated RTO wide reliability requirement reflects the less stringent 1 day in 10 years loss of load expectation. The difference in reliability standards for an

24 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.

25 The contribution percentages are the five year historical average of the DC portion of Pepco zone's load during the yearly maximum load hour.

individual LDA and the RTO is intended to capture the diversity benefit. However, if a Pepco/DC FRR service area were created, the FRR UCAP obligation would reflect only the 1 day in 10 years loss of load expectation, which is a less stringent reliability standard than the 1 day in 25 years that would apply if Pepco/DC remained in the PJM Capacity Market.[26]

Table 7 shows that the total capacity in Pepco/DC offered in the 2021/2022 RPM BRA is not enough to meet the Pepco/DC FRR obligation. Pepco/DC would need to secure capacity both from resource owners in Pepco/DC and capacity resources outside Pepco/DC to meet the FRR UCAP obligation for the Pepco/DC FRR service area.

Table 7 shows unforced capacity offered, FRR UCAP obligation plus the EE add back and shortfall for Pepco/DC. In the 2021/2022 BRA, 83.9 MW UCAP were offered in the DC portion of the Pepco LDA. The Pepco/DC FRR obligation for the 2021/2022 Delivery Year is 2,064.2 MW. The Pepco/DC needs to import 1,980.3 MW UCAP or 95.9 percent of the FRR UCAP obligation from capacity resources located outside DC.

Table 7 Capacity, FRR obligation and shortfall for DC [27]

Modeled LDA	Zone	Capacity (UCAP MW)	FRR Obligation (UCAP MW) plus EE add back	Shortfall (UCAP MW)	Shortfall (Percent)
Pepco	Pepco	83.9	2,064.2	(1,980.3)	(95.9%)
Total DC		83.9	2,064.2	(1,980.3)	(95.9%)

Table 8 shows the LDA, modeled LDA and parent LDA for the Pepco Zone. The DC area is located entirely within the Pepco Zone. 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. The Pepco Zone is located within the Pepco Modeled LDA, which is a part of the SWMAAC parent LDA.

Table 8 LDA and parent LDA of zones located in DC

Zone	LDA	Modeled LDAs	Parent LDA
Pepco	Pepco	Pepco	SWMAAC

Table 9 shows the net CONE times B offer cap applicable to the Pepco LDA and the clearing price of the Pepco LDA in the 2021/2022 BRA.[28]

26 This result, which has been part of the RPM design from its inception, should be reviewed to ensure its consistency with the design of FRRs and the capacity market. In the future, this rule could be changed to ensure consistency.

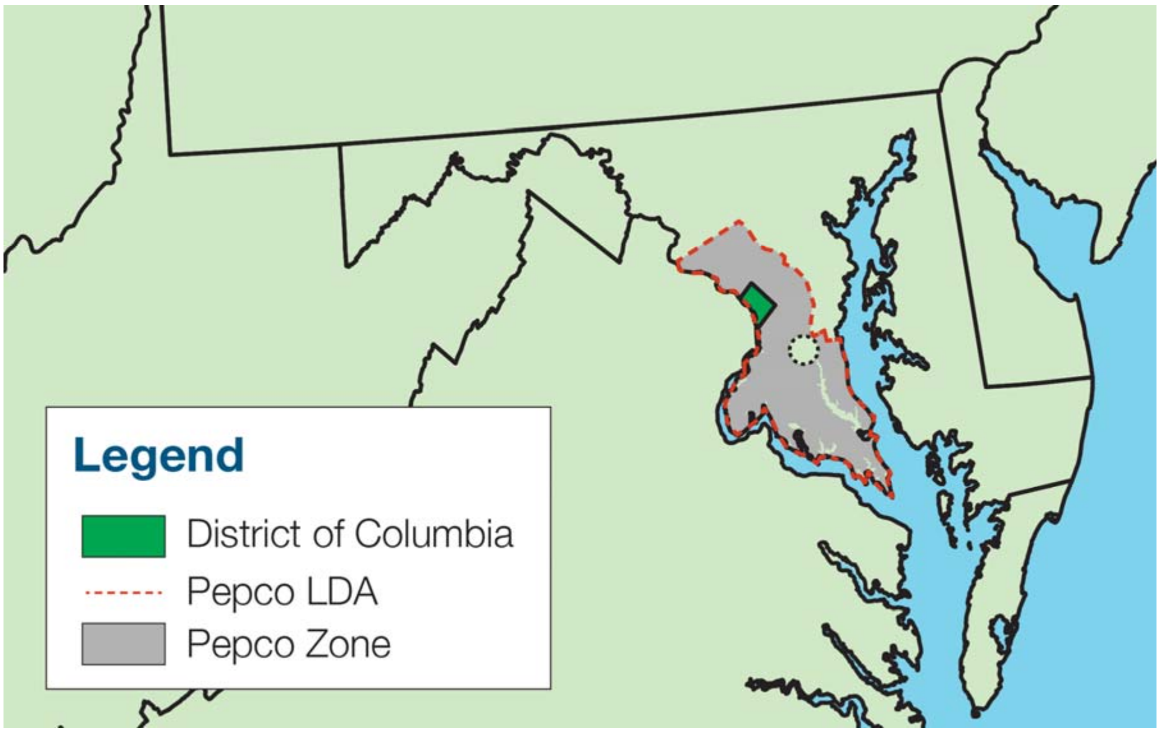
27 The capacity includes the annual equivalent of matched seasonal resources. Since the 2020/2021 Delivery Year, RPM rules allow seasonal resources to offer in the capacity market. Complementary seasonal capacity resources are matched within the auction clearing process.

Table 9 Net CONE times B offer cap for the Pepco zone in DC and clearing price for DC

Zone	FRR UCAP Obligation (MW) plus EE add back	Offer Cap ($ per MW-day)	2021/2022 BRA Clearing Price ($ per MW-day)
Pepco	2,064.2	$210.86	$140.00
DC	2,064.2	$210.86	$140.00

Figure 1 is a map of the Pepco Zone, Pepco LDA and DC.

Figure 1 DC zones and modeled locational deliverability areas [29]



[28] 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).

[29] PJM defines Pepco LDA as a Zonal LDA. The PJM definition of the Pepco LDA includes only generation and load connected to the 230 kV and lower transmission system. See "PJM Manual 14 B: PJM Region Transmission Planning Process," § C2.2 Current Locational Deliverability Area Definitions, Rev. 48 (October 1, 2020).

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.[30] [31] 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.[32]

The Reliability Assurance Agreement (RAA) defines the purpose of the FRR alternative.[33]

> 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.[34]

> 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.

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

31 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.

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

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

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

> 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."

An entity must request to elect the existing FRR option no later than four months prior to the BRA for the first delivery year of the election. 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 or terminate its FRR election by providing written notice to PJM no later than two months prior to the BRA for the effective delivery year.[35]

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[35] 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.

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 (a) 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 (b) 1,300 MW.[36] The Pepco/DC FRR does not have excess capacity to sell in the RPM auctions. The Pepco/DC FRR does not have enough capacity to meet the Pepco/DC FRR requirement.

Results

Scenario 1

In Scenario 1, an FRR is established that includes all of the DC portion of the Pepco LDA (Pepco/DC) and the Pepco/DC FRR procures the entire Pepco/DC FRR UCAP obligation of 2,064.2 MW at a rate equal to the 2021/2022 net CONE times B offer caps applicable to the Pepco LDA ($210.86 per MW-day).[37] Pepco/DC has 83.9 MW UCAP or 95.9 percent fewer MW than needed to meet its FRR obligation. The Pepco/DC FRR would need to contract with capacity resources outside Pepco/DC to cover the deficit. If a Pepco/DC FRR service area were created, the Pepco/DC FRR would be required to procure 2,064.2 MW UCAP, 127.1 MW (5.8 percent) less than if Pepco/DC remained in the PJM Capacity Market. In Scenario 1, summer capacity resources in Pepco/DC are matched with winter

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

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

capacity resources in Pepco/DC such that the total annual equivalent price is less than or equal to the 2021/2022 net CONE times B offer cap applicable to the Pepco LDA ($210.86 per MW-day). The unmatched seasonal resources are mapped to the rest of SWMAAC LDA.

This is a sensitivity analysis based on the assumption that the owners of capacity resources in the Pepco/DC FRR would request payment at the existing offer cap and that all capacity resources would be paid the same price. It is expected that the actual price for capacity in the Pepco/DC FRR would be the result of a negotiation between the owners of the required capacity, and the load in DC.[38] The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Table 10 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 clearing prices would remain the same.

Table 11 shows the gross and net load charges to Pepco/DC for the 2021/2022 BRA and for Scenario 1. The net load charges when Pepco/DC is included in the PJM Capacity Market are net of Capacity Transfer Rights (CTRs) payments to load.[39] CTRs are analogous to 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. 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.[40]

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38 This could also include the owners of capacity that could be imported, limited by the CETL.

39 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.

40 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 11 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 Pepco/DC were $112,398,484. In the 2021/2022 RPM BRA, the load in the Pepco/DC did not receive CTR credits. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Pepco/DC were $112,398,484.

If a Pepco/DC FRR were created and the capacity price for Pepco/DC were equal to the net CONE times B offer cap applicable to the Pepco LDA ($210.86 per MW-day), the load charges for Pepco/DC would have been $158,865,961, an increase of $46,467,477, or 41.3 percent higher than in the 2021/2022 BRA (Table 11).

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 Pepco/DC.

Table 12 shows the net load charges for the RTO excluding the load in the Pepco/DC 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 Pepco/DC FRR, were $9,602,572,688. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the RTO excluding Pepco/DC were $9,274,446,191.

Under Scenario 1, the gross load charges for the 2021/2022 RPM BRA for the RTO excluding Pepco/DC would have been $9,604,707,465. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for the RTO excluding Pepco/DC, would have been $$9,276,347,534, an increase of $1,901,343, or less than one percent.

If DC were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 10 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	$140.00	$0.00	0.0%
Rest of MAAC	$140.00	$140.00	$0.00	0.0%
Rest of EMAAC	$165.73	$165.73	$0.00	0.0%
Rest of SWMAAC	$140.00	$140.00	$0.00	0.0%
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	$140.00	$0.00	0.0%
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	$140.00	$0.00	0.0%
DAY	$140.00	$140.00	$0.00	0.0%
DEOK	$140.00	$140.00	$0.00	0.0%

Table 11 Net load charges for Pepco/DC (Scenario 1)[41]

DC FRR	BRA	Scenario 1	Change	Percent
Zonal UCAP Obligation (MW UCAP)	2,191.2	2,064.2	(127.1)	(5.8%)
Zonal Capacity Price ($/MW-day)	$140.53	$210.86	$70.33	50.0%
Gross Load Charges	$112,398,484	$158,865,961	$46,467,477	41.3%
Value of CTRs	$0	$0	$0	0.0%
Net Load Charges	$112,398,484	$158,865,961	$46,467,477	41.3%

Table 12 Net load charges for RTO excluding Pepco/DC (Scenario 1)

RTO (Excluding DC)	BRA	Scenario 1 and Scenario 2	Change	Percent
Zonal UCAP Obligation	161,436.1	161,464.7	28.6	0.0%
Gross Load Charges	$9,602,572,688	$9,604,707,465	$2,134,777	0.0%
Value of CTRs	$328,126,497	$328,359,931	$233,434	0.1%
Net Load Charges	$9,274,446,191	$9,276,347,534	$1,901,343	0.0%

41 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.

Scenario 2

In Scenario 2, an FRR is established that includes all of DC portion of the Pepco LDA (Pepco/DC) and the Pepco/DC FRR procures the entire Pepco/DC FRR UCAP obligation of 2,064.2 MW at a rate equal to the clearing prices in the 2021/2022 RPM BRA applicable to the Pepco LDA ($140.00 per MW-day). Pepco/DC has 83.9 MW UCAP or 95.9 percent fewer MW than needed to meet its FRR obligation. The Pepco/DC FRR would need to contract with capacity resources outside Pepco/DC to cover the deficit. If a Pepco/DC FRR service area were created, Pepco/DC would be required to procure 2,064.2 MW UCAP, 127.1 MW (5.8 percent) less than if Pepco/DC remained in the PJM Capacity Market. In Scenario 2, summer capacity resources in Pepco/DC are matched with winter capacity resources in Pepco/DC such that the total annual equivalent price is less than or equal to the clearing price in the 2021/2022 RPM BRA applicable to the Pepco LDA ($140.00 per MW-day). The unmatched seasonal resources are mapped to the rest of SWMAAC LDA.

Table 10 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 clearing prices would remain the same.

Table 13 shows the gross and net load charges to Pepco/DC for the 2021/2022 BRA and for Scenario 2. The net load charges when Pepco/DC is included in the PJM Capacity Market are net of CTRs.

Table 13 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 Pepco/DC were $112,398,484. In the 2021/2022 RPM BRA, the load in the Pepco/DC did not receive CTR credits. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Pepco/DC were $112,398,484.

If a Pepco/DC FRR were created and the capacity price for Pepco/DC were equal to the Pepco LDAs' clearing price in the BRA ($140.00 per MW-day), the load charges for Pepco/DC would have been $105,478,680, a decrease of $$6,919,804, or 6.2 percent lower than in the 2021/2022 BRA.[42]

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 lower FRR UCAP obligation for the load in the Pepco/DC.

42 The $140.53 per MW-day is the net load price for Pepco Zone, the capacity price charged to the load in the Pepco Zone. In the 2021/2022 BRA, the FRR Obligation adjusted for EE add back, the clearing price for Pepco was $140.00 per MW-day. The difference of $0.53 per MW-day was due to Pepco's portion of funding for cleared Price Responsive Demand (PRD) credits and make whole payments to the seasonal resources.

Table 14 shows the net load charges for the RTO excluding the load in Pepco/DC for Scenario 2. The net load charges for the RTO excluding Pepco/DC are the same as Scenario 1.

If DC were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 13 Net load charges for Pepco/DC (Scenario 2)

DC FRR	BRA	Scenario 2	Change	Percent
Zonal UCAP Obligation	2,191.2	2,064.2	(127.1)	(5.8%)
Zonal Capacity Price ($/MW-day)	$140.53	$140.00	($0.53)	(0.4%)
Gross Load Charges	$112,398,484	$105,478,680	($6,919,804)	(6.2%)
Value of CTRs	$0	$0	$0	0.0%
Net Load Charges	$112,398,484	$105,478,680	($6,919,804)	(6.2%)

Table 14 Net load charges for RTO excluding Pepco/DC (Scenario 2)

RTO (Excluding DC)	BRA	Scenario 1 and Scenario 2	Change	Percent
Zonal UCAP Obligation	161,436.1	161,464.7	28.6	0.0%
Gross Load Charges	$9,602,572,688	$9,604,707,465	$2,134,777	0.0%
Value of CTRs	$328,126,497	$328,359,931	$233,434	0.1%
Net Load Charges	$9,274,446,191	$9,276,347,534	$1,901,343	0.0%