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VIA ELECTRONIC FILING

July 15, 2022

Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, North Carolina 27603-5918

Re: Docket No. E-22, Sub 418

Dear Ms. Dunston:

Consistent with Article XIV of the Agreement and Stipulation of Settlement filed with the North Carolina Utilities Commission and the Commission's order of December 22, 2016, in Docket No. E-22, Sub 532, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM Interconnection, L.L.C., submits the attached report. The report includes the information specified in Paragraph 6 of the Joint Offer of Settlement between Dominion North Carolina Power and PJM Interconnection, L.L.C., filed in Docket No. E-22, Sub 532, on December 16, 2004.

The Commission has indicated that the Market Monitor should file these reports in Docket No. E-22, Sub 418.

Please contact Joseph Bowring if you have any questions about this matter, at 610 271-8051 or at *joseph.bowring@monitoringanalytics.com*.

Yours truly,

Jeffrey Mayes

Jeffrey Mayes, General Counsel

cc: Andrea R. Kells, Esq.

REPORT TO THE NORTH CAROLINA PUBLIC UTILITIES COMMISSION

Congestion in the Dominion Service Territory in North Carolina: 2020/2021 and 2021/2022

The Independent Market Monitor for PJM

July 15, 2022

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Overview of Congestion Calculations

This report provides details of congestion in the part of the Dominion Zone in North Carolina for the 2020/2021 and 2021/2022 planning periods.

Congestion is defined to be load payments in excess of generation revenues, excluding marginal losses. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.[1] The difference is congestion.[2] As a result, congestion belongs to load and should be returned to load. Congestion is not the difference in CLMP between nodes. Congestion is not the billing line item labeled congestion.[3]

Congestion calculations are for the part of the Dominion Zone in North Carolina. The report includes congestion event hours for the constraints that caused the congestion revenue paid by load and the congestion collected from that load for each constraint.[4]

In this report, congestion equals the total congestion charges paid by load at the buses in the part of the Dominion Zone in North Carolina minus the total congestion credits received by all generation that supplied that load, given the transmission constraints, regardless of the location of the generation in the PJM system. Congestion is calculated on a constraint specific basis which reflects the differences between credits and charges caused by binding transmission limits on the power flow from generators, regardless of the location of that generation, to load in the part of the Dominion Zone in North Carolina.

The congestion calculation reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and capability of transmission

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1 Load is generically referred to as withdrawals and generation is generically referred to as injections, unless specified otherwise.

2 The difference in losses is not part of congestion.

3 PJM billing examples can be found in *2021 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

4 Congestion event hours are hours in which a transmission constraint is binding. In the day-ahead market, an interval equals one hour. In the real-time market, an interval equals five minutes. In order to have a consistent metric for day-ahead and real-time congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any one of its component five-minute intervals is constrained.

facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

In an LMP system, one way to ensure that load receives congestion revenues is to use well designed FTRs. Direct assignment of congestion revenues to load would be preferable. FTRs were the mechanism initially selected in PJM to return the congestion costs that load pays in an LMP market. ARRs were added later.

The existing PJM ARR/FTR design does not serve as an efficient mechanism for returning congestion to load, as a result of an FTR design that was flawed from its introduction and as a result of various distortions added to the design since its introduction. The distortions include the definition of target allocations based on day-ahead congestion only, the fact that ARR holders cannot set the sale price for congestion revenue rights, the return of FTR auction revenues to FTR buyers when profit targets are not met, the failure to assign all FTR auction revenues to ARR holders, the differences between modeled and actual system capability, the definition and allocation of surplus, and the numerous cross subsidies among participants. The fundamental distortion was the assignment of the rights to congestion revenue based on specific generation to load transmission contract paths. This approach retained the contract path based view of congestion rooted in physical transmission rights and inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load paths, and if the distortions subsequently introduced into the FTR design not been added, many of the subsequent issues with the FTR design would have been avoided. The design should simply have provided for the return of all congestion revenues to load. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

Locational Marginal Price (LMP)

Components

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus can be divided into three components: the system marginal price (SMP) or energy component, the congestion component (CLMP), and the marginal loss component (MLMP). SMP, MLMP and CLMP are the simultaneous products of the least cost, security constrained dispatch of system resources to meet system load and the use of a load-weighted reference bus. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

SMP is defined as the incremental price of energy for the system, given the current dispatch, at the load-weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load-weighted reference bus. The load-weighted reference bus is not a fixed location but varies with the distribution of load at system load buses. For SMP, energy means the component of LMP not associated with a binding transmission constraint. All other locational prices that result from the least cost, security constrained market solution are higher or lower than this reference point price (SMP) as a result of binding constraints. The reference bus is a point of reference. For a given market solution, changing the reference bus does not change the LMP for any node on the system, but changes only the elements of the nodal prices that are positive or negative due to the binding constraints in that solution.

CLMP is defined as the incremental price of meeting load at each bus when a transmission constraint is binding, based on the shadow price associated with the relief of a binding transmission constraint in the security constrained optimization. (There can be multiple binding transmission constraints.) CLMPs are positive or negative depending on location relative to binding constraints and relative to the load-weighted reference bus. In an unconstrained system CLMPs will be zero. This means that CLMP at a bus is not congestion. The difference between CLMPs at buses is not congestion, it is just the absolute LMP difference between the two buses caused by transmission constraints. CLMP is the portion of the LMP at a bus that indicates whether the LMP at that bus is higher or lower than the marginal price of energy SMP at the selected reference bus due to binding transmission constraints. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load. The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation to provide that energy, after virtual bids have been settled. Congestion equals the sum of day-ahead and balancing congestion.

MLMP is defined as the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load.

Table 1 shows the real-time load-weighted average LMP components for PJM and for the part of the Dominion Zone in North Carolina for the 2012/2013 through 2021/2022 planning periods.[5]

Table 1 PJM and the Dominion Zone in North Carolina real-time load-weighted average LMP components (Dollars per MWh): 2012/2013 through 2021/2022 planning period

	PJM				NC			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2012/2013	$37.87	$37.82	$0.03	$0.02	$39.21	$37.74	$1.19	$0.28
2013/2014	$54.05	$54.06	($0.03)	$0.02	$61.29	$55.33	$5.72	$0.25
2014/2015	$40.23	$40.18	$0.03	$0.02	$43.57	$40.79	$2.27	$0.51
2015/2016	$28.80	$28.75	$0.04	$0.01	$31.89	$28.95	$2.66	$0.27
2016/2017	$30.57	$30.52	$0.03	$0.01	$31.97	$30.44	$1.24	$0.29
2017/2018	$36.98	$36.93	$0.03	$0.02	$42.92	$38.12	$4.16	$0.64
2018/2019	$31.67	$31.62	$0.03	$0.02	$32.15	$31.29	$0.56	$0.30
2019/2020	$23.72	$23.68	$0.02	$0.02	$24.81	$23.42	$1.17	$0.22
2020/2021	$26.02	$25.98	$0.03	$0.02	$27.29	$25.81	$1.20	$0.27
2021/2022	$52.44	$52.35	$0.06	$0.03	$57.16	$52.37	$4.03	$0.77

Table 2 shows the day-ahead, load-weighted, average LMP components for PJM and for the part of the Dominion Zone in North Carolina for the 2012/2013 through 2021/2022 planning periods.

Table 2 PJM and the Dominion Zone in North Carolina day-ahead load-weighted average LMP components (Dollars per MWh): 2012/2013 through 2021/2022 planning periods

	PJM				NC			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2012/2013	$37.44	$37.35	$0.10	($0.00)	$38.85	$37.60	$1.07	$0.17
2013/2014	$54.59	$54.36	$0.23	($0.00)	$59.20	$55.51	$4.51	($0.82)
2014/2015	$40.74	$40.49	$0.27	($0.02)	$45.77	$41.33	$3.82	$0.61
2015/2016	$29.15	$29.02	$0.14	($0.01)	$32.69	$29.56	$2.85	$0.28
2016/2017	$30.86	$30.78	$0.10	($0.02)	$32.61	$31.13	$1.39	$0.09
2017/2018	$35.94	$35.86	$0.09	($0.01)	$41.55	$37.32	$3.83	$0.40
2018/2019	$32.37	$32.24	$0.14	($0.01)	$33.86	$32.42	$1.36	$0.08
2019/2020	$23.38	$23.35	$0.04	($0.01)	$24.68	$23.61	$1.17	($0.10)
2020/2021	$25.94	$25.81	$0.11	$0.01	$27.01	$25.97	$1.14	($0.10)
2021/2022	$51.94	$51.62	$0.22	$0.09	$54.84	$51.95	$3.03	($0.14)

[5] See *2021 State of the Market Report for PJM, Volume 2:* Section 11: Congestion and Marginal Losses.

Table 3 shows the real-time monthly load-weighted average CLMP components of LMP for PJM and for the part of the Dominion Zone in North Carolina for the 2012/2013 through 2021/2022 planning periods.

Table 3 PJM and the Dominion Zone in North Carolina real-time monthly load-weighted average CLMP component (Dollars per MWh): 2012/2013 through 2021/2022 planning periods

							PJM						
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Annual
2012/2013	$0.03	$0.02	$0.02	$0.01	$0.03	$0.03	$0.04	$0.02	$0.07	$0.06	$0.03	$0.01	$0.03
2013/2014	($0.01)	($0.33)	($0.06)	$0.02	$0.04	$0.03	($0.00)	$0.00	($0.05)	$0.02	$0.00	($0.02)	($0.03)
2014/2015	$0.02	($0.02)	($0.00)	$0.03	$0.13	$0.03	$0.01	$0.01	$0.02	$0.05	$0.05	$0.02	$0.03
2015/2016	$0.03	$0.02	$0.04	$0.07	$0.02	$0.06	$0.02	$0.02	$0.04	$0.06	$0.05	$0.04	$0.04
2016/2017	$0.01	$0.02	$0.03	$0.01	$0.02	$0.02	$0.03	$0.04	$0.07	$0.06	$0.02	$0.02	$0.03
2017/2018	$0.05	$0.01	$0.04	$0.04	$0.09	$0.01	$0.02	$0.01	$0.08	$0.02	$0.01	($0.01)	$0.03
2018/2019	$0.02	$0.01	$0.03	$0.02	$0.02	$0.04	$0.02	$0.02	$0.06	$0.03	$0.03	$0.01	$0.03
2019/2020	$0.01	$0.01	$0.01	$0.01	$0.03	$0.01	$0.02	$0.01	$0.05	$0.05	$0.04	$0.02	$0.02
2020/2021	$0.01	$0.04	$0.04	$0.06	$0.02	$0.03	$0.04	$0.03	$0.02	$0.02	$0.02	$0.02	$0.03
2021/2022	$0.08	$0.05	$0.04	$0.11	$0.21	$0.04	$0.02	$0.03	$0.03	$0.04	$0.10	$0.03	$0.06
							NC						
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Annual
2012/2013	$2.95	$0.51	$1.65	$0.59	$2.08	($0.08)	$0.89	$2.26	$0.70	$2.49	($0.49)	$0.50	$1.19
2013/2014	$33.08	$1.79	$12.60	$0.40	$3.09	($0.12)	($2.04)	$5.33	$4.29	$0.62	$1.96	$1.60	$5.72
2014/2015	$0.96	$2.29	$6.67	$5.16	$3.68	$1.67	$0.21	$2.06	$2.76	$3.83	($0.69)	$0.19	$2.27
2015/2016	$3.86	$2.27	$1.97	$4.44	$0.00	$5.30	$3.01	$1.68	$0.68	$3.03	$2.53	$2.67	$2.66
2016/2017	$2.14	$0.86	$0.45	$0.87	$1.27	$0.90	$0.25	($0.24)	$2.77	$4.21	$2.05	$0.44	$1.24
2017/2018	$19.01	$0.73	$9.81	$2.16	$4.08	$0.10	$0.84	$0.71	$2.44	$3.37	$1.25	$1.17	$4.16
2018/2019	($0.63)	$0.67	$0.80	$0.61	$1.72	$1.09	$0.02	($0.18)	$1.19	$1.94	$0.53	($0.43)	$0.56
2019/2020	$0.40	$0.26	$0.32	$2.07	$0.55	$0.76	$0.64	$1.12	$3.04	$2.91	$2.13	$0.26	$1.17
2020/2021	$0.52	$2.26	$2.28	$2.71	$3.76	($0.01)	($1.46)	$0.75	$1.42	$2.16	$1.23	$0.83	$1.20
2021/2022	$9.65	$1.99	$2.22	$4.39	$3.91	$1.10	$0.55	$2.57	$2.77	$5.15	$10.16	$3.43	$4.03

Table 4 shows the day-ahead monthly load-weighted average CLMP components of LMP for PJM and for the part of the Dominion Zone in North Carolina for the 2012/2013 through 2021/2022 planning periods.

Table 4 PJM and the Dominion Zone in North Carolina day-ahead monthly load-weighted average CLMP component (Dollars per MWh): 2012/2013 through 2021/2022 planning periods

	PJM												
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Annual
2012/2013	$0.12	$0.04	$0.03	$0.03	$0.10	$0.17	$0.20	$0.10	$0.18	$0.03	$0.09	$0.05	$0.10
2013/2014	$0.76	$0.30	$0.19	$0.02	$0.14	$0.18	$0.29	$0.09	$0.34	$0.06	$0.07	$0.20	$0.23
2014/2015	$0.38	$0.77	$0.29	($0.06)	$0.20	$0.23	$0.23	$0.12	$0.18	$0.27	$0.36	$0.14	$0.27
2015/2016	$0.19	$0.17	$0.07	$0.04	$0.06	$0.30	$0.18	$0.12	$0.23	$0.10	$0.09	$0.09	$0.14
2016/2017	$0.08	$0.01	$0.01	($0.02)	($0.06)	$0.16	$0.26	$0.29	$0.19	$0.06	($0.01)	$0.13	$0.10
2017/2018	$0.56	$0.06	($0.07)	($0.01)	($0.05)	$0.10	$0.13	$0.03	$0.03	$0.02	$0.06	$0.16	$0.09
2018/2019	$0.22	$0.03	$0.06	$0.02	($0.01)	$0.11	$0.05	$0.17	$0.15	$0.27	$0.24	$0.33	$0.14
2019/2020	$0.01	$0.01	($0.06)	($0.08)	($0.03)	$0.02	$0.19	$0.08	$0.06	$0.03	$0.02	$0.15	$0.04
2020/2021	$0.05	$0.35	$0.17	($0.10)	($0.04)	$0.04	$0.28	$0.27	$0.06	($0.00)	($0.05)	$0.17	$0.11
2021/2022	$1.39	$0.39	($0.04)	($0.08)	$0.06	$0.27	$0.22	$0.40	$0.09	($0.11)	($0.30)	$0.03	$0.22
	NC												
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Annual
2012/2013	$2.60	$1.30	$1.50	$0.59	$1.66	($0.04)	$0.33	$1.53	$0.50	$1.63	$0.40	$0.97	$1.07
2013/2014	$11.39	$2.89	$10.34	$1.72	$3.63	$1.01	$0.56	$4.04	$11.01	$2.86	$2.31	$1.81	$4.51
2014/2015	$2.71	$10.27	$5.60	$4.45	$4.77	$2.61	$2.64	$2.79	$4.06	$3.01	$1.09	$1.17	$3.82
2015/2016	$3.93	$3.05	$2.47	$4.03	$0.90	$4.70	$3.88	$1.92	$1.36	$2.41	$2.07	$2.71	$2.85
2016/2017	$1.73	$0.75	$0.98	$1.14	$1.33	$1.26	($0.16)	$0.62	$2.30	$4.13	$2.18	$1.45	$1.39
2017/2018	$15.01	$1.09	$4.99	$2.11	$7.13	$0.68	$0.98	$1.16	$3.00	$2.60	$1.52	$2.72	$3.83
2018/2019	$2.02	$0.81	$1.26	$0.80	$1.99	$1.93	$0.65	$0.39	$1.70	$3.15	$1.58	$0.28	$1.36
2019/2020	$0.35	$0.38	$0.26	$0.54	$0.53	$1.21	$0.64	$1.19	$3.04	$2.96	$1.99	$0.79	$1.17
2020/2021	$1.02	$0.94	$1.66	$2.13	$1.86	$0.26	($0.22)	$1.10	$1.71	$2.03	$0.94	$1.26	$1.14
2021/2022	$5.70	$3.04	$2.73	$3.69	$2.56	$1.35	$0.77	$0.76	$2.65	$4.15	$7.22	$2.58	$3.03

Congestion

Load pays congestion. Congestion is the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to binding transmission constraints. Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are not relevant to the calculation of congestion. The CLMPs are a function of the selected reference bus. Holding aside the marginal loss component of LMP, differences in LMPs are caused by binding constraints in the least cost security constrained dispatch market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution, it merely changes the components of the LMP.

In PJM's two settlement system, there is a day-ahead market and there is a real-time, balancing market, that together make up a market day. Congestion is the sum of all congestion related charges and credits from both the day-ahead and balancing market.

In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of each market day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Unlike virtuals, physical load and generation have net MW at the close of a market day's day-ahead and balancing settlement.

Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted, average LMP.

The residual difference between total load charges (day-ahead and balancing) and generation credits (day-ahead and balancing) after virtual bids have settled their day-ahead and balancing positions is congestion. That is, congestion is the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to binding transmission constraints, after virtual bids are settled at the end of the market day.

Load is the source of the net surplus after generation is paid and virtuals are settled at the end of the market day. Load pays congestion. Virtuals do not pay congestion.

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load CLMP charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation CLMP credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint.

Constraint specific CLMPs are determined relative to a reference bus, where there is no congestion and no losses. For purposes of allocating the congestion of an individual constraint, the reference bus for each constraint calculation is moved to the point that is just upstream of the constraint (the bus with the greatest negative price effect from the constraint), allowing any positive price effects of the constraint to be reflected as a positive CLMP.

Congestion is attributed to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the CLMP charges collected from that load due to that constraint. The congestion collected from each load bus due to a constraint is equal to the CLMP caused by that constraint times the MW of load at that load bus. This calculation is done for both day-ahead congestion and balancing congestion.

The system marginal price (SMP) is uniform for all areas, while the total of the congestion components of Locational Marginal Price (LMP) will either be positive or negative in a specific area, meaning that actual LMPs are above or below the SMP.[6] The area affected by a constraint will have increased prices and the unconstrained area will have lower prices.

Day-ahead CLMP charges and credits are based on MWh and CLMP in the day-ahead energy market. Balancing CLMP charges and credits are based on load or generation deviations between the day-ahead and real-time energy markets and CLMP in the real-time energy market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where real-time CLMP is positive, positive balancing congestion costs will result. Similarly, if there is a positive load deviation at a bus where real-time CLMP is negative, negative balancing congestion costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time CLMP is positive, negative balancing congestion costs will result. Similarly, if there is a negative load deviation at a bus where real-time CLMP is positive, negative balancing congestion costs will result.

In order to provide a more detailed explanation of the congestion calculations from which the total CLMP charges are derived, each category of congestion is defined and a table of the CLMP charges or credits associated with each category is provided at the end of the report.[7]

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6 The SMP is the price of the distributed load reference bus. The price at the reference bus is equivalent to the five minute real-time or hourly day-ahead load-weighted PJM LMP.

7 For details of CLMP accounting, see *2021 State of the Market Report for PJM, Volume 2:* Section 11: Congestion and Marginal Losses.

The explicit CLMP charges calculated for the part of the Dominion Zone in North Carolina represent the charges associated with point to point transactions that source or sink in the part of the Dominion Zone in North Carolina. For example, if a transaction is sourced in Pennsylvania and sinks in the part of the Dominion Zone in North Carolina, the charges would be based on the MWh of the transaction multiplied by the difference between the sink CLMP and the source CLMP. The resulting CLMP charges are allocated to the zone and state of the sink location, in the part of the Dominion Zone in North Carolina. The sink location is the buyer's location and reflects the cost to the buyer of the internal purchase or external transaction.

Table 5 shows the combined day-ahead and balancing withdrawal charges, injection credits, and explicit CLMP charges for the part of the Dominion Zone in North Carolina for the 2016/2017 through 2021/2022 planning periods.

Table 5 Total congestion costs (Dollars (Millions)) for the Dominion Zone in North Carolina by category: 2016/2017 through 2021/2022 planning periods

	Congestion Costs (Millions)			
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total
2016/2017	$1.9	($2.5)	($0.1)	$4.3
2017/2018	$3.3	($4.6)	($0.3)	$7.7
2018/2019	$1.0	($2.4)	($0.2)	$3.2
2019/2020	$1.0	($1.8)	($0.3)	$2.6
2020/2021	$2.0	($1.9)	($0.2)	$3.6
2021/2022	$11.1	($1.7)	($0.5)	$12.3

Table 6 shows the congestion costs categories separated by day-ahead and balancing to show the contributions from both the day-ahead and real-time markets for the 2016/2017 through 2021/2022 planning periods.

Table 6 Total day-ahead and balancing congestion costs (Dollars (Millions)) for the Dominion Zone in North Carolina by category: 2017/2018 through 2021/2022 planning periods

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
2016/2017	$1.9	($2.8)	$0.1	$4.8	($0.0)	$0.3	($0.2)	($0.4)	$4.3
2017/2018	$3.0	($5.3)	($0.4)	$7.8	$0.4	$0.6	$0.1	($0.1)	$7.7
2018/2019	$1.0	($2.7)	$0.1	$3.9	($0.0)	$0.3	($0.4)	($0.7)	$3.2
2019/2020	$1.0	($2.1)	$0.2	$3.3	$0.0	$0.2	($0.5)	($0.7)	$2.6
2020/2021	$2.5	($2.2)	$0.3	$5.0	($0.5)	$0.3	($0.6)	($1.4)	$3.6
2021/2022	$11.9	($3.1)	$0.7	$15.8	($0.8)	$1.4	($1.3)	($3.5)	$12.3

Table 7 shows the monthly day-ahead and balancing congestion costs for the 2020/2021 and 2021/2022 planning periods.

Table 7 Monthly congestion costs (Dollars (Millions)) for the Dominion Zone in North Carolina: 2020/2021 and 2021/2022 planning periods

	Congestion Costs (Millions)					
	2020/2021			2021/2022		
	Day-ahead	Balancing	Total	Day-ahead	Balancing	Total
Jun	$0.3	($0.1)	$0.2	$0.4	($0.1)	$0.3
Jul	$0.4	($0.1)	$0.3	$0.4	($0.0)	$0.4
Aug	$0.5	($0.1)	$0.4	$1.0	($0.2)	$0.8
Sep	$0.5	($0.1)	$0.4	$0.8	($0.1)	$0.7
Oct	$0.3	($0.0)	$0.3	$0.7	($0.1)	$0.6
Nov	$0.3	($0.1)	$0.3	$1.1	($0.2)	$0.9
Dec	$0.6	($0.2)	$0.4	$0.7	($0.0)	$0.6
Jan	$0.4	($0.1)	$0.2	$4.8	($1.3)	$3.5
Feb	$0.4	($0.3)	$0.1	$1.6	($0.7)	$0.9
Mar	$0.4	($0.1)	$0.2	$0.6	($0.3)	$0.3
Apr	$0.4	($0.1)	$0.3	$0.7	($0.1)	$0.5
May	$0.5	($0.0)	$0.4	$3.0	($0.3)	$2.7
Total	$5.0	($1.4)	$3.6	$15.8	($3.5)	$12.3

Table 8 lists the top 15 constraints affecting congestion costs for the part of the Dominion Zone in North Carolina for the 2021/2022 planning period. Table 8 shows the type of constraints (Line, Transformer, Flowgate, or Interface), the location of the constraints and the constraint specific congestion revenue collected from the load in the Dominion Zone in North Carolina in the 2021/2022 planning period. Table 9 provides the type of constraint (Line, Transformer, Flowgate, or Interface), the location of the constraint, the congestion event hours affecting the Dominion Zone in North Carolina in the 2021/2022 planning period.

Table 8 Congestion cost (Dollars (Millions)) details for the top 15 constraints affecting the Dominion Zone in North Carolina congestion costs: 2021/2022 planning period

			Congestion Costs (Millions)								
			Day-Ahead			Balancing			Total		
Constraint	Type	Location	Internal to DOM	External to DOM	Total	Internal to DOM	External to DOM	Total	Internal to DOM	External to DOM	Grand Total
Greys Point - Harmony Village	Line	DOM	$3.0	$0.0	$3.0	($1.2)	$0.0	($1.2)	$1.8	$0.0	$1.8
Brambleton - Evergreen Mills	Line	DOM	$1.6	$0.0	$1.6	$0.0	$0.0	$0.0	$1.6	$0.0	$1.6
Nottingham	Other	PECO	$0.0	$0.9	$0.9	$0.0	($0.1)	($0.1)	$0.0	$0.8	$0.8
Cumberland - Juniata	Line	PPL	$0.0	$0.6	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	$0.6
Rappahanock - White Stone	Line	DOM	$0.7	$0.0	$0.7	($0.1)	$0.0	($0.1)	$0.6	$0.0	$0.6
Idylwood - Clark	Line	DOM	$0.5	$0.0	$0.5	$0.0	$0.0	$0.0	$0.5	$0.0	$0.5
Bedington - Black Oak	Interface	500	$0.0	$0.7	$0.7	$0.0	($0.2)	($0.2)	$0.0	$0.5	$0.5
Three Mile Island	Transformer	500	$0.0	$0.5	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	$0.5
AP South	Interface	500	$0.0	$0.5	$0.5	($0.0)	($0.2)	($0.2)	($0.0)	$0.3	$0.3
Hope Creek - Silver Run	Line	PSEG	$0.0	$0.3	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	$0.3
Ashburn - Cochran Mill	Line	DOM	$0.3	$0.0	$0.3	($0.0)	$0.0	($0.0)	$0.3	$0.0	$0.3
Prest - Tibb	Flowgate	MISO	$0.0	$0.3	$0.3	$0.0	($0.1)	($0.1)	$0.0	$0.3	$0.3
Conastone - Northwest	Line	BGE	$0.0	$0.3	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.2	$0.2
Juniata	Transformer	500	$0.0	$0.2	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	$0.2
Brighton	Other	500	$0.0	$0.2	$0.2	$0.0	($0.1)	($0.1)	$0.0	$0.2	$0.2
Top 15 Total			$6.1	$4.6	$10.6	($1.3)	($0.7)	($2.0)	$4.7	$3.9	$8.6
All Other Constraints			$1.1	$4.1	$5.2	($0.2)	($1.3)	($1.5)	$0.8	$2.8	$3.7
Total			$7.1	$8.7	$15.8	($1.6)	($1.9)	($3.5)	$5.6	$6.7	$12.3

Table 9 Top 15 constraints affecting the Dominion Zone in North Carolina congestion costs: 2021/2022 planning period

			Event Hours	
Constraint	Type	Location	Day-Ahead	Real-Time
Greys Point - Harmony Village	Line	DOM	855	592
Brambleton - Evergreen Mills	Line	DOM	616	-
Nottingham	Other	PECO	3,108	2,044
Cumberland - Juniata	Line	PPL	868	379
Rappahanock - White Stone	Line	DOM	522	149
Idylwood - Clark	Line	DOM	302	133
Bedington - Black Oak	Interface	500	188	226
Three Mile Island	Transformer	500	1,089	481
AP South	Interface	500	301	162
Hope Creek - Silver Run	Line	PSEG	1,137	284
Ashburn - Cochran Mill	Line	DOM	213	106
Prest - Tibb	Flowgate	MISO	2,444	2,124
Conastone - Northwest	Line	BGE	351	141
Juniata	Transformer	500	437	165
Brighton	Other	500	1,017	1,286
Top 15 Total			13,448	8,272
All Other Constraints			24,208	18,830
Total			37,656	27,102

Table 10 shows the congestion cost details of the top 15 constraints affecting the part of the Dominion Zone in North Carolina for the 2020/2021planning period. Table 10 shows the type of constraints (Line, Transformer, Flowgate, or Interface), the location of the constraints and the constraint specific congestion revenue collected from the load in the Dominion Zone in North Carolina in the 2020/2021 planning period. Table 11 provides the type of constraints (Line, Transformer, Flowgate, or Interface), the location of the constraints affecting the Dominion Zone in North Carolina in the 2020/2021 planning period.

Table 10 Congestion cost (Dollars (Millions)) details for the top 15 constraints affecting the Dominion Zone in North Carolina: 2020/2021 planning period

			Congestion Costs (Millions)								
			Day-Ahead			Balancing			Total		
Constraint	Type	Location	Internal to DOM	External to DOM	Total	Internal to DOM	External to DOM	Total	Internal to DOM	External to DOM	Grand Total
Bagley - Graceton	Line	BGE	$0.0	$0.6	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	$0.6
Pleasant View - Ashburn	Line	DOM	$0.3	$0.0	$0.3	($0.0)	$0.0	($0.0)	$0.3	$0.0	$0.3
Conastone - Graceton	Line	BGE	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	$0.2
Three Mile Island	Transformer	500	$0.0	$0.2	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	$0.2
White Stone - Harmony Village	Line	DOM	$0.4	$0.0	$0.4	($0.3)	$0.0	($0.3)	$0.2	$0.0	$0.2
Cumberland - Juniata	Line	PPL	$0.0	$0.2	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.1	$0.1
Bagley - Raphael Road	Line	BGE	$0.0	$0.1	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	$0.1
Graceton - Safe Harbor	Line	BGE	$0.0	$0.1	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	$0.1
Kerr Dam - Palmer Springs	Line	DOM	$0.1	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.1	($0.0)	$0.1
Conastone	Transformer	500	$0.0	$0.1	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	$0.1
Conastone - Peach Bottom	Line	500	$0.0	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1
Nottingham	Other	PECO	$0.0	$0.1	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	$0.1
Ashburn - Cochran Mill	Line	DOM	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.1	$0.0	$0.1
Five Forks - Rock Ridge Tap	Line	BGE	$0.0	$0.1	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	$0.1
Gainesville	Transformer	DOM	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.1	$0.0	$0.1
Top 15 Total			$1.0	$1.8	$2.8	($0.3)	($0.0)	($0.3)	$0.7	$1.8	$2.4
All Other Constraints			$0.3	$1.9	$2.2	($0.1)	($1.0)	($1.1)	$0.2	$0.9	$1.1
Total			$1.3	$3.7	$5.0	($0.4)	($1.1)	($1.4)	$0.9	$2.7	$3.6

Table 11 Top 15 constraints affecting the Dominion Zone in North Carolina congestion costs: 2020/2021 planning period

			Event Hours	
Constraint	Type	Location	Day-Ahead	Real-Time
Bagley - Graceton	Line	BGE	2,987	1,708
Pleasant View - Ashburn	Line	DOM	513	56
Conastone - Graceton	Line	BGE	581	123
Three Mile Island	Transformer	500	1,357	769
White Stone - Harmony Village	Line	DOM	1,233	286
Cumberland - Juniata	Line	PPL	647	299
Bagley - Raphael Road	Line	BGE	1,015	678
Graceton - Safe Harbor	Line	BGE	1,271	768
Kerr Dam - Palmer Springs	Line	DOM	478	70
Conastone	Transformer	500	99	24
Conastone - Peach Bottom	Line	500	913	16
Nottingham	Other	PECO	962	529
Ashburn - Cochran Mill	Line	DOM	121	36
Five Forks - Rock Ridge Tap	Line	BGE	239	29
Gainesville	Transformer	DOM	67	23
Top 15 Total			12,483	5,414
All Other Constraints			23,747	16,120
Total			36,230	21,534

ARRs/FTRs as a Congestion Offset in the Dominion Zone in North Carolina

ARRs are allocated to zonal load based on historical generation to load transmission paths, in many cases based on pre 1999 information. ARRs are allocated within zones based on zonal base load (Stage 1A) and zonal peak loads (other Stages). ARR revenue is the result of the prices that result from the sale of FTRs through the FTR auctions. ARR revenue for each zone is the revenue for the ARRs that sink in each zone.

Congestion paid by load in a zone is the total difference between what the zonal load pays in CLMP charges net of payments to the generation that serves the zonal load.

Table 12 shows the congestion offsets paid to load in the part of the Dominion Zone in North Carolina. The congestion offsets include: the allocation of ARR revenue; self scheduled FTR revenue; and the allocation of end of planning period surplus. Table 12 also shows payments by load in the part of the Dominion Zone in North Carolina. Load payments include: day-ahead congestion; balancing congestion; and the allocation of M2M payments.

The offset percentage shown in Table 12 is the share of the congestion payments that are returned to load in the part of the Dominion Zone in North Carolina.

Table 12 Dominion Zone in North Carolina ARR and FTR total congestion offset (in millions) for ARR holders: 2016/2017 through 2021/2022 planning periods

Planning Period	ARR Credits	FTR Credits	Balancing + M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
2018/2019	$0.3	$1.6	($0.7)	$0.3	$1.6	$3.9	($0.7)	($0.1)	$3.0	54.6%
2019/2020	$0.4	$1.2	($0.8)	$0.5	$1.2	$3.3	($0.7)	($0.0)	$2.5	48.9%
2020/2021	$1.0	$3.6	($1.6)	$0.0	$3.0	$5.0	($1.4)	($0.0)	$3.5	84.9%
2021/2022	$1.3	$14.9	($1.0)	$0.0	$15.2	$17.4	($0.5)	($0.1)	$16.9	90.0%

The amount of the offset realized by the part of the Dominion Zone in North Carolina load serving entities varies by planning period. The offsets are a function of the assignment of ARRs, the valuation of ARRs in the FTR auctions and the congestion revenue from self scheduled ARRs. If the prices for FTRs are high relative to realized congestion, the offset provided by ARR is increased relative to cases where the prices for FTRs are low relative to realized congestion. While the amount of congestion that is returned to the load varies by planning period, PJM's ARR/FTR design has consistently failed to return the congestion revenues to the load in the part of the Dominion Zone in North Carolina that paid it.

Table 13 shows the total congestion offset that would be available to the part of the Dominion Zone in North Carolina ARR holders if the ARR holders self scheduled all their allocated ARRs as FTRs for the 2018/2019 through 2021/2022 planning periods.

In an ARR/FTR market with correctly defined rights, it should be possible for load serving entities (LSE) in the Dominion Zone to recover 100 percent, no more and no less, of the congestion they pay by claiming all assigned rights. The results in Table 13 show that, under the current design, it is not possible for load to recover the congestion that load pays. Load cannot recover the congestion it pays to the network because the rights assigned to LSEs do not align with actual network sources of congestion paid by the load. Due to this misalignment of congestion rights relative to actual network use, the proportion of congestion that can be recovered by LSEs varies considerably from one planning period to another, with some LSEs able to recover far less than the congestion they pay and others able to collect far more congestion than they pay.

Path based congestion rights are not and cannot be made consistent with how load is actually served by the wholesale electricity market based on actual network use. The results in Table 13 show that the share of congestion revenues available to load varies significantly by planning period, for the same set of rights for a number of reasons, including ARR over and under allocations relative to realized network flows and mismatched source and sink points.

Table 13 Offset available to load if all ARRs self scheduled (Revised)

Planning Period	SS FTR	Bal+M2M	Congestion+ M2M	Offset
2018/2019	$2.1	($0.7)	$3.0	46.0%
2019/2020	$1.3	($0.7)	$2.5	24.9%
2020/2021	$4.9	($1.6)	$3.5	93.6%
2021/2022	$25.3	($1.0)	$16.9	144.1%

The results in Table 12 and Table 13 illustrate the fundamental issues with the FTR/ARR design in PJM. If the FTR/ARR design were implemented correctly, the offsets to load would equal congestion payments by load.

Table 14 shows the share of ARR MW, by stage, for ARRs with paths that source inside or outside the Dominion Zone, and congestion that originate inside or outside the Dominion Zone. This illustrates one of the fundamental issues with the path based approach which originated (in 1999) in a cost of service design where most load was served by, or assumed to be served by, generation in the same zone as load. In fact, in the PJM market, which operates as an integrated network, a significant proportion of congestion is based on constraints that are not in the same zone as load. The path based approach cannot reflect the actual congestion paid by load. Paths do not reflect the way that load is actually served in a network system like PJM.

Table 14 Share of ARRs and congestion that source in/out of Dominion Zone

	Stage 1A		Stage 1B		Stage 2		Total		Congestion	
	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone
2020/2021	0.4%	64.1%	0.0%	34.2%	0.0%	1.4%	0.4%	99.6%	75.1%	24.9%
2021/2022	0.3%	61.1%	0.0%	37.6%	0.0%	0.9%	0.4%	99.6%	54.7%	45.3%

ARR Stage 1A overallocations to LSEs are a significant contributor to the misalignment of congestion rights relative to actual network use. Stage 1A ARRs MW are awarded regardless of whether the physical transmission system can support the theoretical flows from the Stage 1A source and sink points. In the case where Stage 1A ARR MW flows exceed physical transmission limits, PJM modifies the modeled transmission limits in the ARR/FTR market to accommodate the flow. Any FTRs accommodated by these modeling adjustments will have FTR target allocations that exceed the amount of congestion caused by the transmission constraints in the actual day-ahead and real-time market results. To compensate for this overallocation, and to support full funding of FTR target allocations for the entire system, PJM makes significant reductions in Stage 1B and Stage 2 ARR allocations, and a corresponding reduction in available FTRs elsewhere in the ARR/FTR market. These arbitrary adjustments of the ARR/FTR market model result in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs.

Table 15 shows the Stage 1A overallocated ARR MW for the entire Dominion Zone, based on whether the source point is inside or outside of the Dominion Zone, by planning period (2020/2021 and 2021/2022).

Table 15 Stage 1A overallocated ARR MW by source in/out of Dominion Zone

	Out of Zone MW	In Zone MW
2020/2021	0	661.9
2021/2022	0	1072.0

The Greys Point – Harmony Village Line constraint was the largest contributor to congestion in the Dominion Zone in North Carolina in 2020/2021 (Table 8). There was a significant overallocation of ARRs and FTRs on the Greys Point – Harmony Village Line compared to actual network flows in 2021/2022. This overallocation was a significant source of the unusual increase in the available congestion offset from self scheduling available ARRs as FTRs in 2021/2022 in the Dominion Zone. Table 16 shows FTR target allocations from the Greys Point - Harmony Village Line constraint compared to actual congestion from the constraint based on actual flows. The dollar amounts in Table 16 are not limited to the FTR target allocations and congestion associated with just the Dominion Zone in North Carolina, but includes the total target allocation and congestion effects of the constraint, although most (99.9 percent of the day-ahead congestion and 98.5 percent of the balancing congestion) effects are Dominion Zone specific. The required payments to FTRs (self-scheduled ARRs and FTRs purchased directly) resulting from this constraint were about twice the level of actual congestion on this constraint. The total target allocations to be paid out were $90,396,866, while the actual congestion available to fund the payments was only $41,452,090. As a result, the offset available to load if all ARRs had been self scheduled would have been significantly higher than actual congestion.

Table 16 FTR Target Allocations relative to Congestion Generated by Greys Point – Harmony Village: 2021/2022 planning period

Facility	FTR Target Allocations (No Self Scheduled FTRs)	Self Scheduled FTR Target Allocations	Total FTR Target Allocations (All)	Percent Self Scheduled FTR	Day Ahead Congestion	Balancing Congestion	Total Congestion	Day Ahead Overallocation	Total Overallocation
Greys Point - Harmony Village	$28,154,135	$62,242,731	$90,396,866	68.9%	$63,483,567	-$22,031,477	$41,452,090	$26,913,299	$48,944,776

Conclusion

Total congestion increased from the 2020/2021 planning period to the 2021/2022 planning period.

In the 2020/2021 planning period, load in the part of the Dominion Zone in North Carolina ARR holders received only 84.9 percent of the congestion paid by that load. Even if ARR holders in the Dominion Zone in North Carolina had self scheduled all their ARRs in the 2020/2021 planning period, they would only have been able to offset 93.6 percent of the congestion they paid.

In the 2021/2022 planning period, load in the part of the Dominion Zone in North Carolina ARR holders received only 90.0 percent of the congestion paid by that load. If ARR holders in the Dominion Zone in North Carolina had self scheduled all their ARRs in the 2021/2022 planning period, they would have been able to offset 144.1 percent of the congestion they paid.

Table 17 Congestion Definitions

Congestion Category	Calculation
Day-Ahead Implicit Withdrawal CLMP Charges	Day-Ahead Demand MWh * Day-Ahead CLMP
Day-Ahead Implicit Injection CLMP Credits	Day-Ahead Supply MWh * Day-Ahead CLMP
Day-Ahead Explicit CLMP Charges	Day-Ahead Transaction MW * (Day-Ahead Sink CLMP - Day-Ahead Source CLMP)
Day-Ahead Total Congestion Costs	Day-Ahead Implicit Withdrawal CLMP Charges - Day-Ahead Implicit Injection CLMP Credits + Day-Ahead Explicit CLMP Charges
Balancing Implicit Withdrawal CLMP Charges	Balancing Demand MWh * Real-Time CLMP
Balancing Implicit Injection CLMP Credits	Balancing Supply MWh * Real-Time CLMP
Balancing Explicit CLMP Costs	Balancing Transaction MW * (Real-Time Sink CLMP - Real-Time Source CLMP)
Balancing Total Congestion Costs	Balancing Implicit Withdrawal CLMP Charges - Balancing Implicit Injection CLMP Credits + Balancing Explicit CLMP Costs
Total Congestion Costs	Day-Ahead Total Congestion Costs + Balancing Total Congestion Costs

MWh Category	Definition
Day-Ahead Demand MWh	Cleared Demand, Decrement Bids, Energy Sale Transactions
Day-Ahead Supply MWh	Cleared Generation, Increment Bids, Energy Purchase Transactions
Real-Time Demand MWh	Load and Energy Sale Transactions
Real-Time Supply MWh	Generation and Energy Purchase Transactions
Balancing Demand MWh	Real-Time Demand MWh - Day-Ahead Demand MWh
Balancing Supply MWh	Real-Time Supply MWh - Day-Ahead Supply MWh