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March 5, 2021

VIA Electronic Filing

Ms. Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

Re: In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2020
Docket No. E-100, Sub 167
Reply Comments of Dominion Energy North Carolina

Dear Ms. Campbell:

Enclosed for filing in the above-referenced proceeding on behalf of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina, are the *Reply Comments of Dominion Energy North Carolina*.

Please do not hesitate to contact me if you have any questions. Thank you for your assistance in this matter.

Very truly yours,

/s/Andrea R. Kells

ARK:kjg

Enclosure

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 167

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Biennial Determination of Avoided	)	**REPLY COMMENTS OF**
Cost Rates for Electric Utility Purchases	)	**DOMINION ENERGY NORTH**
from Qualifying Facilities – 2020	)	**CAROLINA**

NOW COMES Virginia Electric and Power Company d/b/a Dominion Energy North Carolina ("DENC" or the "Company") and, pursuant to the North Carolina Utilities Commission's ("Commission") February 23, 2021, *Order Granting Further Extension of Time* submits these Reply Comments in response to the Initial Statement of the Public Staff and the Joint Initial Comments of the Southern Alliance for Clean Energy ("SACE"), North Carolina Clean Energy Business Alliance ("NCCEBA"), and the North Carolina Sustainable Energy Association ("NCSEA" and together with SACE and NCCEBA, the "Joint Intervenors") filed in this proceeding on January 25, 2021.

I. INTRODUCTION

With its Initial Statement and Exhibits submitted on November 2, 2020 ("Initial Filing"), DENC proposed updated avoided energy and capacity rates under its standard offer rate schedules, Schedule 19-FP and Schedule 19-LMP. The Company also proposed limited revisions to its standard offer contracts to add provisions to govern energy storage components of proposed qualifying facilities ("QFs") and presented a protocol for avoidance of the re-dispatch charge approved in the Commission's April 15, 2020 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* issued in Docket No. E-100, Sub 158 ("Sub 158 Order"). On December 16, 2020, and

December 23, 2020, the Company filed corrected proposed standard avoided energy rates and supporting exhibits ("Corrected Energy Rates").

II. REPLY COMMENTS

A. Public Staff Initial Statement

In its initial comments, the Public Staff stated that based on its review it finds the capital cost inputs and other assumptions incorporated in DENC's proposed Schedule 19-FP capacity rates reasonable.[1] In addition, the Public Staff found that the capacity credits and other assumptions incorporated in DENC's proposed rates for swine and poultry QFs are reasonable for the determination of avoided capacity credits.[2] The Public Staff also stated that, with regard to the Company's avoided energy cost modeling, it has reviewed the PLEXOS inputs and believes the inputs to the model and the output data from the model to be reasonable for determination of DENC's avoided energy costs.[3]

1. RDC Avoidance Protocol

As discussed in the Initial Filing, in its final order in the previous biennial avoided cost proceeding ("Sub 158 Case"), the Commission approved the Company's proposal to adjust the avoided energy cost payments to intermittent non-dispatchable QFs to reflect the increase in system supply costs – specifically, re-dispatch costs – caused by these generators, in an amount of \$0.78/MWh.[4] The Company continues to apply this re-dispatch charge ("RDC") for purposes of this proceeding.

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[1] Initial Statement of the Public Staff ("Public Staff") at 21.
[2] *Id*. at 23.
[3] *Id*. at 27.
[4] Sub 158 Order at 112.

In the Sub 158 Order, the Commission also directed the Company to file a proposed protocol for avoidance of the RDC.[5] In its Initial Filing, DENC proposed that the RDC can be reduced to the extent the QF reduces the variability of its output through the use of an energy storage device ("ESD"). The Company defined an ESD as a component of a QF facility that uses energy storage technology, including but not limited to battery storage. The Company proposed to calculate the reduction in variability as the percent reduction in variability from a case without storage to a case with storage. The output for the case without storage would be the actual metered output of the facility excluding the impact of storage. The output for the case with storage would be the actual metered output for the facility including the impact of storage. Determining the impact of storage would require that the storage device is separately metered.

For each case, on a calendar year basis, the Company proposed to calculate variability as the sum of the hourly absolute output variance from a QF-provided generation forecast. The percent reduction in variability would be calculated by subtracting the ratio of the variability of the case with storage to the variability of the case without storage from one. DENC would then calculate a credit to the RDC as follows: (1) the percent reduction multiplied by (2) the RDC rate multiplied by (3) the total calendar year output (MWh) of the case with storage. To be eligible for the RDC reduction, a QF must provide DENC with an hourly generation output forecast for every hour of the year. For the first year of the contract, the QF must provide the forecast on or before 90 days prior to the facility's commercial operations date ("COD"). For subsequent contract years, the QF may update the forecast on or before 90 days before

[5] Sub 158 Order at 113.

the start of every calendar year of the contract; if no updated forecast is provided, DENC would utilize the previously provided forecast to calculate the RDC reduction credit. Every April, DENC would calculate the RDC reduction using the prior calendar year forecast and metered data. DENC would provide the RDC reduction as a line item credit with the first payment following the April calculation.

In its initial comments, the Public Staff stated that it did not object to the protocol as proposed and may respond further in its reply comments.[6] The Public Staff stated that the proposal protocol is reasonable largely because the Company's QF load reduction estimates incorporate QF output from the prior day (in addition to other variables), such that over time, as a controlled solar generator ("CSG") consistently delivers more predictable output in an attempt to adhere to its forecast, DENC's QF load reduction estimate takes that predictability into account.[7]

The Public Staff added, however, that the RDC credit depends on the type of forecast the CSG provides as well as how the CSG dispatches the ESD, and noted that a CSG could provide different types of forecasts depending on whether it wants to use its ESD to "smooth" its output profile or to shift energy from off-peak to on-peak hours. The Public Staff questioned whether ratepayers would actually benefit more from energy shifting dispatch than from smoothing dispatch, even though a CSG that is shifting energy would qualify for a higher RDC credit than a CSG that is seeking to smooth output.[8] In order to address its concerns, the Public Staff recommended that DENC monitor the types of forecasts and the ESD dispatch behavior for CSGs that attempt to

[6] Public Staff at 34-35.
[7] *Id.* at 34.
[8] *Id*. at 35-36.

avoid the RDC and include this information, as well as an analysis of actual solar volatility of CSGs in DENC's service territory, in its future avoided cost filings.[9] The Public Staff clarified that these biennial reports would be similar to the SISC Avoidance reports recommended by NCSEA, NCCEBA, and the Public Staff for DEP and DEC in the Sub 158 Case.[10]

DENC's proposed RDC Avoidance Protocol is a reasonable proxy for estimating the reduction in re-dispatch costs incurred by CSGs. The proposed Protocol can decrease the costs to customers by improving the load forecasts; as CSGs consistently deliver more predictable output, the Company's forecasting tools will incorporate the data in the load forecast process. The Company does not object to the Public Staff's recommendation that DENC monitor, for CSGs that attempt to avoid the RDC, such CSG's forecasts and behavior and include that information and an analysis of actual solar volatility of CSGs in DENC's service territory in its future biennial avoided cost filings. DENC clarifies that its willingness to accept this recommendation is based on its understanding that the Company's monitoring and reporting obligation would be limited to CSGs seeking to avail themselves of the RDC avoidance protocol that are actually paired with ESDs. In addition, for clarity, if the Commission adopts this recommendation, the Company plans to monitor this information on an annual basis, consistent with the RDC avoidance protocol structure of using annual forecasts.

The Public Staff also recommended that DENC specifically address CSGs seeking RDC avoidance in each future fuel rider proceeding, providing the specific facility(ies) and amount of RDC credit issued, supporting workpapers, and reports on any

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[9] *Id*. at 37.
[10] *Id.* at 37, fn. 33.

audits performed on CSGs seeking to avoid the RDC. The Public Staff noted that it made the same request of DEP and DEC in the Sub 158 Case. The Company does not object to this proposal, with the same clarification that this position is based on the understanding that the Company's obligation to address this issue in future fuel rider proceedings would be limited to CSGs seeking to avail themselves of the RDC avoidance protocol that are actually paired with ESDs.

2. Federal CO2 Costs

As noted by the Public Staff's initial comments, the Company calculated its proposed avoided energy rates using its Alternative Plan B from its 2020 IRP filing in Docket No. E-100, Sub 165. Alternative Plan B is the least-cost plan that complies with all applicable state law, including the Virginia Clean Economy Act[11] and Virginia's membership in the Regional Greenhouse Gas Initiative ("RGGI"), effective January 1, 2021. The Public Staff stated that while there is some uncertainty regarding the projected future cost of RGGI carbon allowances, the existence of a RGGI carbon price is sufficiently "known and verifiable" based on current law.[12] The Public Staff concluded that therefore it is appropriate for DENC to utilize generation expansion Plan B and to include the cost of RGGI carbon allowances in the production cost models that are used to calculate avoided energy rates.[13] The Public Staff also found reasonable the Company's explanation for the difference between the CO2 price included in DENC's avoided energy rates and the RGGI CO2 price forecasts included in DENC's 2020 IRP.[14]

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[11] 2020 Virginia Acts ch. 1193 and ch. 1194.
[12] Public Staff at 38-39.
[13] *Id*. at 39.
[14] *Id*.

As noted by the Public Staff, the CO2 price utilized by the Company to calculate its proposed avoided energy rates also includes a federal CO2 price in addition to the RGGI CO2 price in years 2026 and beyond. The Public Staff argued that the inclusion of a federal CO2 price is inconsistent with prior Public Staff positions and the Commission's Sub 140 Order on Inputs[15] precedent that the avoided energy rate should only include "known and verifiable" costs. The Public Staff asserted that as no federal CO2 price currently exists, such costs should not be included in the calculation of avoided energy rates. The Public Staff recommended that DENC rerun its production cost model using a RGGI price forecast without a federal CO2 price, and file revised avoided energy rates.[16]

The Company calculated its initially filed avoided energy rates including a federal CO2 price because doing so was consistent with Alternative Plan B in the 2020 IRP. However, considering the precedent cited by the Public Staff, the Company does not object to the Public Staff's recommendation, and has re-run the PLEXOS model using the RGGI price forecast but no federal CO2 price. The results of that re-run and the associated revised Schedule 19-FP reflecting revised avoided energy rates are attached as Attachments A through C to these Reply Comments. Attachment A contains DENC's Second Revised Exhibit DENC-6, which shows the calculation of the Company's avoided energy rates to reflect the removal of the federal CO2 price. Attachment B contains the Company's Second Revised Exhibit DENC-16, which shows the revised annualized updated avoided energy rates reflecting this change. Attachment C contains a

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[15] Order Setting Avoided Cost Input Parameters at 8, 42-44, Docket No. E-100, Sub 140 (Dec. 31, 2014) ("Sub 140 Order on Inputs").
[16] Public Staff at 39-40.

modified Schedule 19-FP, which shows the revised avoided energy rates in redline. The Company has shared these revised rates and supporting data with the Public Staff and the Public Staff has informed DENC that it supports them. The Company also shared the revised rates and data with the Joint Intervenors but as of this date has not received a response. If the Commission agrees with the Public Staff on this issue, the Company does not object to using these revised avoided energy rates. As a point of clarification, the Company notes that, as the Public Staff recognizes, the RGGI Only price used in the IRP is a price forecast made under the influence of a federal CO2 price, and the RGGI Only price decline in years 2026 through 2030 is due to downward pressure on emissions resulting from the federal CO2 price. As a result, the RGGI Only price forecast in absence of the Federal CO2 price will actually slightly increase in years 2026 through 2030.[17]

3. Continued Exclusion of Line Loss Adder

As explained in the Initial Filing, in the Sub 158 Order, the Commission found that power backflow on substations in DENC's North Carolina service territory from solar generation on the distribution grid continued to increase such that avoided line loss benefits associated with distributed generation have been reduced or negated, and that it was appropriate that DENC continue not to include a line loss adder in its standard avoided cost payments to solar QFs on its distribution network.[18] In its Initial Filing, the Company stated that for purposes of this proceeding, DENC's avoided energy rates continue to reflect the elimination of the line loss adder.

[17] *Id*. at 40, fn. 40.
[18] Sub 158 Order at 35-36.

In its initial comments, the Public Staff stated that it has reviewed the information filed by the Utilities related to line loss adders and back-feeding of substations and agrees with their proposals. The Public Staff also stated that it will continue to evaluate the appropriateness of line loss adders in future avoided cost proceedings, and recommended that the Commission direct the Utilities to continue to file information to support the removal or inclusion of the line loss adder in proposed avoided cost rates in future avoided cost proceedings.[19] As noted in its December 7, 2020, and January 21, 2021, Sub 158 Additional Issues Initial Report and Status Update filed in this proceeding, the Company plans to update its line loss study for purposes of its November 2021 biennial avoided cost filing.

B. Joint Intervenors

Joint Intervenors' initial comments do not include any recommendations for the Company.[20] The Crossborder Energy Report attached as Exhibit A to Joint Intervenors' initial comments ("Crossborder Report") does, however, make two recommendations that the Company will address briefly out of an abundance of caution.

First, the Crossborder Report states that the utilities use fundamental forecasts for Henry Hub prices from private consultancies IHS and ICF. The Crossborder Report recommends that these forecasts be supplemented with a public Henry Hub forecast, and that the IHS/ICF forecasts be averaged with the Energy Information Administration's ("EIA") 2020 Annual Energy Outlook forecast of Henry Hub prices. With regard to DENC, this means that the Company would use the average of the EIA and ICF forecasts

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[19] Public Staff at 48-49.
[20] Joint Initial Comments of the Southern Alliance for Clean Energy, North Carolina Clean Energy Business Alliance, and the North Carolina Sustainable Energy Association at 18 ("Joint Intervenors").

as its fundamental forecast.[21] The Joint Intervenors' comments apply this recommendation to Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (the "Duke Utilities") but not to DENC.[22] To the extent that this recommendation is considered to apply to the Company, DENC believes its current approach of using the ICF fundamental forecast is appropriate. The Company's use of the ICF forecast to forecast energy prices in avoided cost proceedings has been accepted by the Commission since the 2012 avoided cost proceeding (Docket No. E-100, Sub 136), most recently in the Sub 158 Order,[23] and the Company continues to believe that the ICF forecast of commodity prices is, on its own, appropriate for estimating avoided energy cost rates. ICF forecasts are reputable and respected in the industry and Joint Intervenors have not presented a convincing reason why continued use of the ICF forecast on its own is not reasonable, particularly given the Commission's consistent decisions accepting that approach. Moreover, ICF conducts regional forecasts for electricity as well as natural gas and other commodities, which allows the Company to use relevant and correlated forecasts for system modeling purposes. In contrast, using un-correlated forecasts, by for example mixing ICF price forecasts for energy and other commodities with an EIA forecast for Henry Hub, would skew the dispatch and economic value of the Company's natural gas-fired units.

Second, the Crossborder Report recommends that the utilities use a fuel hedging model other than Black-Scholes method approved in previous avoided cost orders.[24] The Joint Intervenors ask the Commission to direct the Duke Utilities to investigate and apply

[21] Crossborder Energy Report at 2.
[22] Joint Intervenors at 10-11.
[23] Sub 158 Order at 59.
[24] Crossborder Energy Report at 6-10.

what they term a more accurate model or, in the alternative the Joint Intervenors suggest they will revisit the issue in the next avoided cost proceeding to commence in November 2021.[25] While Joint Intervenors do not direct their recommendation to the Company, to the extent that this recommendation is considered to apply to DENC, the Company's position is that the alternative methods suggested by the Crossborder Report are not reasonable approaches to calculating avoided hedging costs for North Carolina. This position is based on several factors, including but not limited to the fact that, as discussed in the Company's reply comments in the Sub 158 Case, both of the methods discussed in the Crossborder Report are based on outdated data and would result in inappropriately inflated hedging values, thereby drastically and unreasonably increasing avoided energy cost rates. In addition, the Commission concluded in the 2014 avoided cost proceeding and again in the Sub 158 Order that hedging benefits should only be valued over the hedging terms actually used by the Utilities.[26] Consistent with this determination, the use of ten or twenty year hedging periods as suggested by the Crossborder Report is far in excess of what is appropriate. Since the Company's typical natural gas hedge financial hedge program could extend approximately 18 to 24 months in the future, it is appropriate that DENC calculate assumed avoided hedging costs using this time frame.

III. CONCLUSION

WHEREFORE, Dominion Energy North Carolina respectfully requests that the Commission accept these Reply Comments and issue an order accepting the Company's Initial Filing, as modified by the Corrected Energy Rates and as discussed herein, and making such other determinations as are necessary and proper.

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[25] Joint Intervenors at 12.
[26] Sub 140 Order on Inputs at 42; Sub 158 Order at 102.

Respectfully submitted,

DOMINION ENERGY NORTH CAROLINA

By: ___*/s/ Andrea R. Kells*_________________

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March 5, 2021

ATTACHMENT A

Second Revised
Exhibit DENC-6
Page 1 of 1

Development of Fixed, Levelized Energy Purchase Prices for QFs
2020 North Carolina Schedule 19 Filing, Docket No. E-100, Sub 167

Sub Period	Name	Abr.	Months	Weekday Hours	Weekend Hours
Sub1	Summer Premium Peak	(S-PP)	Jun-Sep	15-18	
Sub2	Summer On-Peak	(S-On)	Jun-Sep	11-14,19-22	
Sub3	Summer Off-Peak	(S-Off)	Jun-Sep	1-10,23-24	1-24
Sub4	Winter Premium Peak	(W-PP)	Dec-Feb	7-8,18-19	
Sub5	Winter On-Peak(am)	(W-On-AM)	Dec-Feb	9-12	
Sub6	Winter On-Peak(pm)	(W-On-PM)	Dec-Feb	20-22	
Sub7	Winter Off-Peak	(W-Off)	Dec-Feb	1-6,23-24	1-24
Sub8	Shoulder On-Peak	(Sh-On)	Shoulder	7-22	
Sub9	Shoulder Off-Peak	(Sh-Off)	Shoulder	1-6,23-24	1-24

Plexos Results Avoided Energy(¢/kWh)

		Sub1	Sub2	Sub3	Sub4	Sub5	Sub6	Sub7	Sub8	Sub9
1	**2021**	3.978	3.047	2.120	4.088	3.425	3.486	2.986	2.993	2.178
2	**2022**	4.062	3.110	2.107	4.604	3.898	3.916	2.922	2.928	2.108
3	**2023**	4.493	3.438	2.390	4.321	3.649	3.678	2.966	2.825	2.208
4	**2024**	4.779	3.666	2.500	4.519	3.846	3.867	3.279	2.880	2.304
5	**2025**	4.829	3.709	2.556	4.178	3.559	3.595	3.157	2.827	2.256
6	**2026**	5.140	3.942	2.747	4.251	3.549	3.630	3.135	3.005	2.363
7	**2027**	4.715	3.618	2.541	3.892	3.243	3.322	3.053	2.858	2.252
8	**2028**	4.643	3.565	2.502	4.088	3.456	3.486	2.913	2.840	2.235
9	**2029**	4.519	3.472	2.416	3.957	3.347	3.382	2.851	2.844	2.271
10	**2030**	4.710	3.620	2.530	4.009	3.398	3.425	2.944	2.927	2.369
11	**2031**	4.437	3.424	2.403	4.063	3.445	3.501	2.942	2.852	2.313
	Adj for LMP	0.965	0.976	0.981	0.957	0.961	0.961	0.960	0.961	0.975
	Avoided Hedge Benefits (¢/kwh)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002

Adjusted for LMP Impact and Avoided Hedge Benefit (¢/kWh)

		Sub1	Sub2	Sub3	Sub4	Sub5	Sub6	Sub7	Sub8	Sub9
1	**2021**	3.840	2.976	2.082	3.913	3.292	3.353	2.867	2.878	2.126
2	**2022**	3.921	3.038	2.069	4.407	3.746	3.767	2.805	2.815	2.058
3	**2023**	4.337	3.358	2.346	4.137	3.507	3.538	2.848	2.716	2.155
4	**2024**	4.613	3.580	2.455	4.326	3.696	3.720	3.149	2.769	2.249
5	**2025**	4.661	3.623	2.510	4.000	3.420	3.458	3.031	2.718	2.202
6	**2026**	4.961	3.850	2.697	4.069	3.411	3.492	3.010	2.889	2.306
7	**2027**	4.551	3.534	2.495	3.726	3.117	3.196	2.932	2.748	2.198
8	**2028**	4.482	3.482	2.457	3.914	3.322	3.353	2.797	2.730	2.181
9	**2029**	4.362	3.391	2.372	3.788	3.217	3.254	2.738	2.734	2.216
10	**2030**	4.546	3.535	2.484	3.838	3.266	3.295	2.827	2.814	2.312
11	**2031**	4.283	3.344	2.359	3.889	3.311	3.368	2.825	2.742	2.258

Variable Energy Rate (¢/kWh)

Sub1	Sub2	Sub3	Sub4	Sub5	Sub6	Sub7	Sub8	Sub9	Non-time differentiated
3.880	3.007	2.075	4.160	3.519	3.560	2.836	2.846	2.092	2.630

DISCOUNT RATE = 6.830%

Beginning of Year 2021 Present Value (¢/kWh)

	PV Factor		Sub1	Sub2	Sub3	Sub4	Sub5	Sub6	Sub7	Sub8	Sub9
1	0.9361	**2021**	3.594	2.786	1.949	3.663	3.081	3.139	2.684	2.694	1.990
2	0.8762	**2022**	3.435	2.662	1.813	3.862	3.282	3.301	2.458	2.466	1.803
3	0.8202	**2023**	3.557	2.754	1.925	3.393	2.876	2.902	2.336	2.228	1.767
4	0.7678	**2024**	3.542	2.749	1.885	3.321	2.837	2.856	2.417	2.126	1.727
5	0.7187	**2025**	3.350	2.604	1.804	2.874	2.458	2.485	2.178	1.953	1.582
6	0.6727	**2026**	3.338	2.590	1.814	2.737	2.295	2.349	2.025	1.944	1.552
7	0.6297	**2027**	2.866	2.225	1.571	2.346	1.963	2.013	1.846	1.730	1.384
8	0.5895	**2028**	2.642	2.053	1.448	2.307	1.958	1.977	1.649	1.609	1.286
9	0.5518	**2029**	2.407	1.871	1.309	2.090	1.775	1.795	1.511	1.509	1.223
10	0.5165	**2030**	2.348	1.826	1.283	1.982	1.687	1.702	1.460	1.453	1.194
		CUMULATIVE	31.078	24.118	16.800	28.576	24.213	24.519	20.565	19.713	15.507
		LEVELIZED RATE	4.390	3.407	2.373	4.037	3.420	3.464	2.905	2.785	2.191

DOMINION ENERGY NORTH CAROLINA
SCHEDULE FP
Year 2020 Proposed Rates (Annualized)
Cents per kWH
Second Revised Proposed Rates filed March 5, 2021

Second Revised Exhibit DENC-16
Page 1 of 2

Performance Adjustment Factor: ~~1.070~~

PROPOSED RATE DESIGN

			Variable		Fixed Long-Term Rates	
Line No.	Description		Rate		10-Year	
1	Energy Credit	Summer - Premium Peak	~~3.280~~	3.880	~~3.514~~	4.390
2	Energy Credit	Summer - On Peak	~~2.999~~	3.007	~~3.309~~	3.407
3	Energy Credit	Summer - Off Peak	~~2.170~~	2.075	~~2.512~~	2.373
4	Energy Credit	Winter - Premium Peak	~~3.773~~	4.160	~~3.693~~	4.037
5	Energy Credit	Winter - On Peak (AM)	~~3.607~~	3.519	~~3.448~~	3.420
6	Energy Credit	Winter - On Peak (PM)	~~3.737~~	3.560	~~3.626~~	3.464
7	Energy Credit	Winter - Off Peak	~~3.149~~	2.836	~~3.075~~	2.905
8	Energy Credit	Shoulder - On Peak	~~2.928~~	2.846	~~2.753~~	2.785
9	Energy Credit	Shoulder - Off Peak	~~2.331~~	2.092	~~2.389~~	2.191
10	Capacity Credit	Summer Month			~~3.245~~	4.000
11	Capacity Credit	Winter Month			~~2.884~~	3.641
12	Capacity Credit	Shoulder Month			~~0.643~~	0.819
13	Annualized Energy		~~2.746~~	2.630	~~2.810~~	2.760
14	Annualized Capacity				~~0.415~~	0.524
15	Annualized Total				~~3.224~~	3.283

Cents/kWh

The Energy Rates shown above are for dispatchable QFs whose generation is not intermittent.
The Energy Rates are decreased by 0.078 cents per kWh for QFs whose generation is intermittent in nature (solar, wind, …).

NOTE: Calculation of Annualized Numbers

Annualized Energy ((S-PP*344)+(S-On*688)+(S-Off*1896)
+(W-PP* 244)+(W-On AM*244)+(W-On PM*183)+(W-Off*1489)
+(Sh-On* 1680)+(Sh-Off*1992))/8760

Annualized Capacity (summer rate*516+ winter rate*504+ shoulder rate*840)/8760

Annualized Total Annualized Energy + Annualized Capacity

Key: Subperiod Abbreviation

Sub Period	Description	Abbreviation
1	Summer - Premium Peak	(S-PP)
2	Summer - On Peak	(S-On)
3	Summer - Off Peak	(S-Off)
4	Winter - Premium Peak	(W-PP)
5	Winter - On Peak (AM)	(W-On-AM)
6	Winter - On Peak (PM)	(W-On-PM)
7	Winter - Off Peak	(W-Off)
8	Shoulder - On Peak	(Sh-On)
9	Shoulder - Off Peak	(Sh-Off)

DOMINION ENERGY NORTH CAROLINA
SCHEDULE FP
Year 2020 Proposed Rates (Annualized)
Cents per kWH
Second Revised Proposed Rates filed March 5, 2021

Performance Adjustment Factor: **2.00**

Cents/kWh

PROPOSED RATE DESIGN

Line No.	Description		Variable Rate		Fixed Long-Term Rates 10-Year	
1	Energy Credit	Summer - Premium Peak	~~3.280~~	3.880	~~3.514~~	4.390
2	Energy Credit	Summer - On Peak	~~2.999~~	3.007	~~3.309~~	3.407
3	Energy Credit	Summer - Off Peak	~~2.170~~	2.075	~~2.512~~	2.373
4	Energy Credit	Winter - Premium Peak	~~3.773~~	4.160	~~3.693~~	4.037
5	Energy Credit	Winter - On Peak (AM)	~~3.607~~	3.519	~~3.448~~	3.420
6	Energy Credit	Winter - On Peak (PM)	~~3.737~~	3.560	~~3.626~~	3.464
7	Energy Credit	Winter - Off Peak	~~3.149~~	2.836	~~3.075~~	2.905
8	Energy Credit	Shoulder - On Peak	~~2.928~~	2.846	~~2.753~~	2.785
9	Energy Credit	Shoulder - Off Peak	~~2.331~~	2.092	~~2.389~~	2.191
10	Capacity Credit	Summer Month			~~6.065~~	7.477
11	Capacity Credit	Winter Month			~~5.391~~	6.805
12	Capacity Credit	Shoulder Month			~~1.202~~	1.531
13	Annualized Energy		~~2.746~~	2.630	~~2.810~~	2.760
14	Annualized Capacity				~~0.775~~	0.979
15	Annualized Total				~~3.585~~	3.738

The Energy Rates shown above are for dispatchable QFs whose generation is not intermittent.
The Energy Rates are decreased by 0.078 cents per kWh for QFs whose generation is intermittent in nature (solar, wind, …).

NOTE: Calculation of Annualized Numbers

Annualized Energy ((S-PP*344)+(S-On*688)+(S-Off*1896)
+(W-PP* 244)+(W-On AM*244)+(W-On PM*183)+(W-Off*1489)
+(Sh-On* 1680)+(Sh-Off*1992))/8760

Annualized Capacity (summer rate*516+ winter rate*504+ shoulder rate*840)/8760

Annualized Total Annualized Energy + Annualized Capacity

Key: Subperiod Abbreviation

Sub Period	Description	Abbreviation
1	Summer - Premium Peak	(S-PP)
2	Summer - On Peak	(S-On)
3	Summer - Off Peak	(S-Off)
4	Winter - Premium Peak	(W-PP)
5	Winter - On Peak (AM)	(W-On-AM)
6	Winter - On Peak (PM)	(W-On-PM)
7	Winter - Off Peak	(W-Off)
8	Shoulder - On Peak	(Sh-On)
9	Shoulder - Off Peak	(Sh-Off)

Schedule 19 - FP
POWER PURCHASES FROM
COGENERATION AND SMALL POWER PRODUCTION
QUALIFYING FACILITIES

I. APPLICABILITY AND AVAILABILITY

Subject to the limitations of this Section I and to the limitations of G.S. § 62-156(b)(1), this schedule is applicable to any qualifying cogeneration or small power production facility, as defined in 18 C.F.R. § 292.203 (Qualifying Facility), which desires to deliver all of its net electrical output to the Company, and has either (1) generating facilities designated as new capacity as defined by 18 C.F.R. § 292.304(b)(1), or (2) generating facilities that meet the criteria of being owned or operated by a small power producer as defined in G.S. § 62-3(27a), and enters into an agreement for the sale of net electrical output to the Company (Agreement).

Unless otherwise provided by a Commission order setting forth different availability dates, this schedule is available to any Qualifying Facility (otherwise eligible pursuant to the terms hereof) that, no later than the date on which proposed rates are filed in the next biennial avoided cost proceeding after Docket No. E-100, Sub 167, (a) has filed a report of proposed construction with the Commission pursuant to Commission Rule R8-65, (b) is a Qualifying Facility, (c) has submitted to the Company a duly executed "Notice of Commitment to Sell the Output of a Qualifying Facility of no Greater than 1 Megawatt Maximum Capacity to Dominion North Carolina Power Company ("Notice of Commitment"), and (d) has submitted a request to interconnect to the Company's system pursuant to Section 2 or Section 3 of the North Carolina Interconnection Procedures ("NCIP"). The form of the Notice of Commitment can be found on the Company's website through the following link: https://www.dominionenergy.com/large-business/selling-power-to-dominion-energy/contracting-to-sell-power. Alternatively, a QF may request a Notice of Commitment form via email to PowerContracts@dominionenergy.com.

Where the Qualifying Facility (QF) elects to be compensated for firm deliveries in accordance with this schedule, the amount of capacity under contract (the "Contracted Capacity") and the initial term of contract shall be limited as set forth below:

(Continued)

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POWER PURCHASES FROM
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(Continued)

I. APPLICABILITY AND AVAILABILITY (Continued)

A. Where the QF operates generating facilities that meet the criteria of being owned or operated by a small power producer as defined in G.S. § 62-3(27a) the amount of Contracted Capacity subject to compensation shall be no greater than 1,000 kW, and the amount of energy purchased during a given hour at rates applicable to firm deliveries shall be no greater than 1,000 kWh in any hour. The initial term of contract for such a QF shall be for a period no longer than 10 years. The minimum term of contract permitted is one year.

B. Where the QF is not defined under Paragraph I.A., the amount of Contracted Capacity subject to compensation shall be no greater than 1,000 kW, and the amount of energy purchased during a given hour at rates applicable to firm deliveries shall be no greater than 1,000 kWh in any hour. The initial term of contract for such a QF shall be for a period no longer than 10 years. The minimum term of contract permitted is one year.

Where the QF elects to be compensated for fixed or variable deliveries in accordance with this schedule, the QF must begin deliveries to the Company within thirty months of the Commission's order in Docket No. E-100, Sub 167 approving this Schedule 19-FP to retain eligibility for the rates contained in this schedule; provided, however, a QF may be allowed additional time to begin deliveries of electrical output to the Company if the QF facilities in question are nearly complete at the end of such thirty month period and the QF is able to demonstrate that it is making a good faith effort to complete its project in a timely manner. Where the QF elects an initial contract term of 10 years, such contract may be renewed for subsequent term(s), at the Company's option, based on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the Company's then avoided cost rates and other relevant factors or (2) set by arbitration.

(Continued)

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POWER PURCHASES FROM
COGENERATION AND SMALL POWER PRODUCTION
QUALIFYING FACILITIES

(Continued)

I. APPLICABILITY AND AVAILABILITY (Continued)

This schedule is not available or applicable to a QF owned by a developer, or affiliate of a developer, who sells electrical output to the Company from another facility located within one-half mile unless: (1) each facility provides thermal energy to different, unaffiliated hosts; or (2) each facility provides thermal energy to the same host, and the host has multiple operations with distinctly different or separate thermal needs. For purposes of this paragraph, the distance between facilities shall be measured from the electrical-generating equipment of each facility.

This schedule is not available or applicable to a QF that utilizes a renewable resource, such as hydroelectric, solar, or wind power facilities, which is owned by a developer, or affiliate of a developer who is selling or will sell electrical output to the Company from another QF using the same renewable energy resource located within one-half mile if the combined output of such renewable resource QFs will exceed 1,000 kWh (ac) in any hour. For purposes of this paragraph, distance between QFs shall be measured from the electrical generating equipment of each facility.

II. MONTHLY BILLING TO THE QF

All sales to the QF will be in accordance with any applicable filed rate schedule. In addition, where the QF contracts for sales to the Company, the QF will be billed a monthly charge equal to one of the following to cover the cost of meter reading and processing:

<u>Metering required</u>	<u>Charge</u>
One non-time-differentiated meter	$16.35
One time-differentiated meter	$33.72
Two time-differentiated meters	$39.05

(Continued)

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POWER PURCHASES FROM
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QUALIFYING FACILITIES

(Continued)

III. DEFINITION OF ON- AND OFF-PEAK HOURS (Energy & Capacity)

A. Energy - On-Peak Hours:

Summer

(i) For the periods beginning at 12:00 midnight May 31 and ending at 12:00 midnight September 30:

The on-peak hours are defined as the hours between 10:00 a.m. and 2:00 p.m., plus 6:00 p.m. through 10:00 p.m. Monday through Friday, excluding holidays considered off-peak.

Winter

(ii) For the periods beginning at 12:00 midnight November 30 and ending at 12:00 midnight February 28 (February 29 in the case of a leap year):

The on-peak hours are defined as those hours between 8:00 a.m. and 12:00 p.m. ("Winter On-Peak(AM)"), plus 7:00 p.m. through 10:00 p.m. ("Winter On-Peak(PM)"), Monday through Friday, excluding holidays considered off-peak.

Shoulder

(i) For the periods beginning at 12:00 midnight February 28 (February 29 in the case of a leap year) and ending at 12:00 midnight May 31; or

(ii) beginning 12:00 midnight September 30 and ending at 12:00 midnight November 30:

The on-peak hours are defined as those hours between 6:00 a.m. and 10:00 p.m., Monday through Friday, excluding holidays considered off-peak.

(Continued)

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POWER PURCHASES FROM
COGENERATION AND SMALL POWER PRODUCTION
QUALIFYING FACILITIES

(Continued)

III. DEFINITION OF ON- AND OFF-PEAK HOURS (Energy & Capacity) (Continued)

B. Energy - Premium-Peak Hours:

<u>Summer</u>

(i) For the periods beginning at 12:00 midnight May 31 and ending at 12:00 midnight September 30:

The premium-peak hours are defined as the hours between 2:00 p.m. and 6:00 p.m., Monday through Friday, excluding holidays considered off-peak.

<u>Winter</u>

(ii) For the periods beginning at 12:00 midnight November 30 and ending at 12:00 midnight February 28 (February 29 in the case of a leap year):

The premium-peak hours are defined as those hours between 6:00 a.m. and 8:00 a.m., plus 5:00 p.m. through 7:00 p.m., Monday through Friday, excluding holidays considered off-peak.

B. Energy - Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified above as on-peak hours. All hours for the following holidays will be considered as off-peak: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, the day after Thanksgiving, and Christmas Day. When one of the above holidays falls on a Saturday, the Friday before the holiday will be considered off-peak; when the holiday falls on a Sunday, the following Monday will be considered off-peak.

C. Capacity - On-Peak Hours:

(Continued)

Superseding Filing Effective For Usage On and After 06-01-20. This Filing Effective For Usage On and After 11-02-20.

Schedule 19 - FP
POWER PURCHASES FROM
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(Continued)

III. DEFINITION OF ON- AND OFF-PEAK HOURS (Energy & Capacity) (Continued)

Summer

(i) For the periods beginning at 12:00 midnight May 31 and ending at 12:00 midnight September 30:

The on-peak hours are defined as the hours between 2:00 p.m. and 8:00 p.m., Monday through Friday, excluding holidays considered off-peak.

Winter

(ii) For the periods beginning at 12:00 midnight November 30 and ending at 12:00 midnight February 28 (February 29 in the case of a leap year):

The on-peak hours are defined as those hours between 5:00 a.m. and 9:00 a.m., plus 5:00 p.m. through 9:00 p.m., Monday through Friday, excluding holidays considered off-peak.

Shoulder

(iii) For the periods beginning at 12:00 midnight February 28 (February 29 in the case of a leap year) and ending at 12:00 midnight May 31; or

(iv) beginning 12:00 midnight September 30 and ending at 12:00 midnight November 30:

The on-peak hours are defined as those hours between 6:00 a.m. and 10:00 a.m., plus 5:00 p.m. through 9:00 p.m., Monday through Friday, excluding holidays considered off-peak.

(Continued)

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POWER PURCHASES FROM
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(Continued)

III. DEFINITION OF ON- AND OFF-PEAK HOURS (Energy & Capacity) (Continued)

D. Capacity - Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified above as on-peak hours. All hours for the following holidays will be considered as off-peak: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, the day after Thanksgiving, and Christmas Day. When one of the above holidays falls on a Saturday, the Friday before the holiday will be considered off-peak;
when the holiday falls on a Sunday, the following Monday will be considered off-peak.

IV. CONTRACT OPTIONS FOR DESIGNATING THE MODE OF OPERATION

The QF shall designate under contract its Mode of Operation from the following options, each of which determines the Company's method of payment.

A. <u>Non-Reimbursement Mode</u>. The QF may contract for the delivery of energy to the Company without reimbursement, designated as the Non-reimbursement Mode of Operation.

B. <u>Energy-Only, Non-time-differentiated or Time-differentiated Variable Mode</u>. The QF may contract for the delivery of energy to the Company where payments are not fixed for the duration of the PPA term; the rates will change with each revision of this schedule, and there is no payment

for capacity to QFs selecting the energy-only option. Where the QF's generation facilities have an aggregate nameplate rating of 100 kW or less the QF may designate the, Non-time-differentiated Mode of Operation.

Regardless of nameplate rating the QF may designate the Time-differentiated Mode of Operation.

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(Continued)

IV. CONTRACT OPTIONS FOR DESIGNATING THE MODE OF OPERATION (Continued)

C. Fixed Mode. The QF may contract for the delivery of both energy and capacity to the Company. The level of capacity which the QF contracts to sell to the Company shall not exceed 1,000 kW.

D. Energy Storage Devices. A QF may elect to contract under options in Paragraphs A through C above with Facility designs that incorporate Energy Storage Devices ("ESD"s). An ESD is defined as a component of a QF facility that uses energy storage technology, including but not limited to battery storage.

V. PAYMENT FOR COMPANY PURCHASES OF ENERGY-ONLY VARIABLE MODE

The QF may contract to receive payment for energy-only determined with each revision of this schedule. These rates will be based upon the QF's Mode of Operation as described below. There are no capacity payments for QFs that contract for energy-only.

A. Non-time-differentiated Mode of Operation. Where the QF's generation facilities have an aggregate nameplate rating of 100 kW or less, and the QF elects the Energy-only, Non-time-differentiated Variable Mode of Operation, the following rates in cents per kWh are applicable:

2.630~~65~~

(Continued)

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(Continued)

V. PAYMENT FOR COMPANY PURCHASES OF ENERGY-ONLY VARIABLE MODE (Continued)

B. Time-differentiated Mode of Operation. Where the QF designates the Energy-only, Time-differentiated Variable Mode of Operation, the following Premium-Peak, On-Peak, and Off-peak rates in cents per kWh are applicable:

Summer – Premium-Peak	3.880 ~~3.932~~
Summer – On-Peak	3.007 ~~3.047~~
Summer – Off-Peak	2.075 ~~2.103~~
Winter – Premium-Peak	4.160 ~~4.217~~
Winter – On-Peak (AM)	3.519 ~~3.567~~
Winter – On-Peak (PM)	3.560 ~~3.609~~
Winter – Off-Peak	2.836 ~~2.874~~
Shoulder – On-Peak	2.846 ~~2.884~~
Shoulder – Off-Peak	2.092 ~~2.119~~

The rates in both A and B above will be redetermined on a biennial basis on each revision of this schedule; provided, however, that for QFs whose electric energy output is produced from intermittent energy sources (e.g., solar, wind), the applicable rate shall be reduced by 0.078 ¢/kWh.

(Continued)

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(Continued)

VI. PAYMENT FOR COMPANY PURCHASES OF ENERGY – FIXED MODE

A QF designating the Fixed Mode of Operation must contract to receive payments for energy under this Section VI based on prices below fixed for the duration of the term. Contract terms for 10 years are available only where the QF is defined under Paragraph I.A.

Summer – Premium-Peak	4.390 ~~4.531~~
Summer – On-Peak	3.407 ~~3.516~~
Summer – Off-Peak	2.373 ~~2.450~~
Winter – Premium-Peak	4.037 ~~4.159~~
Winter – On-Peak (AM)	3.420 ~~3.524~~
Winter – On-Peak (PM)	3.464 ~~3.568~~
Winter – Off-Peak	2.905 ~~2.994~~
Shoulder – On-Peak	2.785 ~~2.872~~
Shoulder – Off-Peak	2.191 ~~2.260~~

Operator shall be paid for energy up to 5% above the Contracted Capacity in any hour at the then applicable energy-only rates under Schedule 19-FP; provided, however, that for QFs whose electric energy output is produced from intermittent energy sources (e.g., solar, wind), that applicable rate shall be reduced by the Re-Dispatch Charge ("RDC") at a rate of 0.078 ¢/kWh. No payment shall be made for generation in excess of 1,000 kWh in any hour.

The RDC may be reduced through the use of an ESD. Any such reduction shall be evaluated to the extent the Seller is able to demonstrate a reduction in the variability of output, determined by considering (1.) the hourly metered output of the Facility with the benefit of the ESD ("Total Output"); (2.) the hourly metered output of the Facility without the benefit of the ESD ("Base Output"); and (3.) an annual forecast of hourly output to be provided by Seller ("QF Forecast").

To the extent there is any reduction in variability, its value shall be calculated on a calendar year basis as the percent change ("Reduction Factor") represented by the

(Continued)

ratio of aggregate differences between Total Output to QF Forecast and Base Output to QF Forecast as follows:

VI. PAYMENT FOR COMPANY PURCHASES OF ENERGY – FIXED MODE (Continued)

$$1 - \left(\frac{\sum_{h=1}^{n} Total\ Output \;\; - Forecast_h}{\sum_{h=1}^{n} Base\ Output \;\; - Forecast_h} \right)$$

Measurement and verification of the Total Output and Base Output requires Operator to install separate metering equipment for the Facility and the ESD. The Reduction Factor shall be used to calculate a credit ("Redispatch Credit") equal to the product of (1.) the Reduction Factor; (2.) the per-megawatt-hour RDC rate; and (3.) the calendar year Total Output:

(Reduction Factor) x (RDC Rate) x (Total Output) = Redispatch Credit.

To be eligible for the Redispatch Credit described above, an Operator must provide the Company with a timely and accurate QF Forecast. After the effective date and no less than 90 days prior to COD, Operator shall provide an initial QF Forecast to the Company. Such forecast will be applied for the duration of the term. Otherwise, Operator may provide a new QF Forecast no less than 90 days before the start of any subsequent calendar year to which it shall be applied. Utilization of the most recent QF Forecast received by the Company shall continue until such time as Operator provides a replacement QF Forecast to be used in the next applicable calendar year.

In each subsequent calendar year, the Company will calculate the Redispatch Credit using the prior calendar year QF Forecast and other inputs determined on the basis of the Facility's metered data. Supervisory Control and Data Acquisition ("SCADA") output data may be used when meter data is not available. The

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Company will issue payment for the Redispatch Credit at regular annual intervals in the form of a line item to offset charges.

VII. PAYMENT FOR COMPANY PURCHASES OF CAPACITY

Company purchases of capacity are applicable only where the QF elects the Fixed Mode of Operation under Section IV.C.

The Company shall pay a levelized capacity payment for each year of the contract term. A swine or poultry waste-fueled generator, or a hydroelectric facility with a capacity of 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed contract term prior to the termination of the Operator's existing contract term is considered to avoid a future capacity need for these designated resource types beginning in the first year following the Operator's existing PPA, pursuant to N.C.G.S. § 62-156(b)(3), as amended. For other types of generation, an Operator's commitment to sell and deliver energy and capacity over a future fixed term is considered to avoid an undesignated future capacity need beginning only in the first year when there is an avoidable capacity need identified in the Company's most recent IRP. Levelized payments to such Operators shall therefore incorporate the need for capacity only in those years that the Company's most recent IRP forecast period has demonstrated a capacity need.

The QF will receive payments for capacity based on the pricing below. Capacity payments are applicable during on-peak hours only. Contract terms no longer than 10 years are available only for QFs described in Paragraph I.A.

For hydroelectric facilities with no storage capability and no other type of generation:	
	Capacity Price
On-Peak (¢/kWh) Summer	7.477

(Continued)

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On-Peak (¢/kWh) Winter	6.805
On-Peak (¢/kWh) Shoulder	1.531

VII. PAYMENT FOR COMPANY PURCHASES OF CAPACITY (Continued)

For all other facilities:	
	Capacity Price
On-Peak (¢/kWh) Summer	4.000
On-Peak (¢/kWh) Winter	3.641
On-Peak (¢/kWh) Shoulder	0.819

Payments will be made to the QF by applying the levelized capacity purchase price above to all kWh delivered to the Company during each on-peak hour, up to 100% of the Contracted Capacity in such hour. There will be no compensation for capacity in excess of the QF's Contracted Capacity in an hour. This capacity price shall be paid for the length of term for capacity sales so established in the contract.

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VIII. PROVISIONS FOR COMPANY PURCHASE OF THE QF GENERATION

A. The QF shall own and be fully responsible for the costs and performance of the QF's:

1. Generating facility in accordance with all applicable laws and governmental agencies having jurisdiction;

2. Control and protective devices as required by the Company on the QF's side of the meter.

B. The sale of electrical output to the Company by a QF at avoided cost rates pursuant to this Schedule 19-FP does not convey ownership to the Company of the renewable energy credits or green tags associated with the QF facility.

C. The QF is responsible for obtaining an interconnection service agreement for delivery of electrical output generated by its facility onto the Company's electrical system. Information on interconnection procedures for the QF's generation interconnection is provided through the Internet at the Company's website:

https://www.dominionenergy.com/large-business/using-our-facilities/parallel-generation-and-interconnection

If the interconnection is subject to FERC jurisdiction, the interconnection will be in accordance with FERC and PJM Interconnection, L.L.C. requirements.

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(Continued)

IX. MODIFICATION OF RATES AND OTHER PROVISIONS HEREUNDER

The provisions of this schedule, including the rates for purchase of energy and Contracted Capacity by the Company, are subject to modification at any time in the manner prescribed by law, and when so modified, shall supersede the rates and provisions hereof. However, payments to QFs with contracts for a specified term at payments established at the time the obligation is incurred shall remain at the payment levels established in their contract.

If the QF terminates its contract to provide Contracted Capacity and energy to the Company prior to the expiration of the contract term, the QF shall, in addition to other liabilities, be liable to the Company for excess capacity and energy payments.

Such excess payments will be calculated by taking the difference between (1) the total capacity and energy payments already made by the Company to the QF and (2) capacity and energy payments calculated based on the levelized capacity and energy purchase price corresponding to the actual term completed by the QF. These excess payments shall also include interest, from the time such excess payments were made, compounded annually at the rate equal to the Company’s most current issue of long-term debt at the time of the contract’s effective date.

X. TERM OF CONTRACT

The term of contract shall be mutually agreed upon by the Company and QF, subject to the applicable maximum term limits set forth in Section I. A and B.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Reply Comments of Dominion Energy North Carolina* filed in Docket No. E-100, Sub 167 was served electronically or via U.S. mail, first class postage prepaid, upon all parties of record.

This, the 5th day of March, 2021.

/s/Andrea R. Kells

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