COMMONWEALTH OF VIRGINIA

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STATE CORPORATION COMMISSION

PUBLIC UTILITY REGULATION

February 25, 2019

Mr. Michael G. Dowd
Director, Air & Renewable Energy Division
Virginia Dept. of Environmental Quality
1111 E. Main St.
Richmond, VA 223219

Dear Mr. Dowd:

This letter is in response to your request for a written narrative describing the development of the SCC Staff's estimate of Regional Greenhouse Gas Initiative ("RGGI")-related customer bill impacts. Enclosed please find a document that more fully describes Staff's RGGI analysis that was discussed at the February 8, 2019 meeting between Staff and DEQ.

If you have any other questions or need additional assistance, please contact me or Greg Abbott at 804-371-9611.

Respectfully,

William Stephens

SCC STAFF ANALYSIS OF CUSTOMER BILL IMPACTS OF VIRGINIA PARTICIPATING IN RGGI
February 21, 2019

EXECUTIVE SUMMARY

During the 2019 Virginia General Assembly session, bills were introduced regarding Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI). Using currently available information and applying certain assumptions, the Staff of the State Corporation Commission ("SCC") made estimates of the potential cost and rate impacts of *joining* or *linking* to RGGI. This document was prepared at the request of the Virginia Department of Environmental Quality ("DEQ") to explain the method and assumptions used by SCC Staff which produced these estimates.

Since DEQ's proposed RGGI rule envisions Virginia linking to RGGI, this document will address the implications of Virginia linking to RGGI. SCC Staff estimates the total cost to Dominion Energy Virginia ("DEV") of linking to RGGI to be about $3.3 billion. SCC Staff estimates the total cost to DEV of joining RGGI to be about $5.9 billion. SCC Staff estimates that linking to RGGI will *increase* the typical DEV ("DEV") residential customer's monthly bill by an average of $6.95 from $120.52 to $127.48 over the 25-year study period.[1]

DEQ estimates that the typical monthly bill for a residential customer served by DEV will *decrease* by an average of $0.54 over the 2020-2030 time period. Given that RGGI is a government imposed cap and trade mechanism designed to impose a carbon tax on the use of fossil fuel generation, and given that DEV owns a significant portfolio of coal and natural gas generation units, the SCC Staff finds DEQ's projection of falling customer bills to be counterintuitive.

DEQ modeled DEV as if it was solely a purchaser of electricity from the grid. In contrast, SCC Staff modeled DEV's actual market structure as a vertically integrated utility that owns fossil fuel generation resources. SCC Staff correctly modeled DEV as both a purchaser of electricity from the grid and as a seller of electricity into the grid.

Chesterfield Units 5 and 6 and Clover Units 1 and 2 are forced into retirement prematurely under SCC Staff's modeling. These units must be paid for by DEV's customers whether the units operate or not. Furthermore, as a member of the PJM Interconnection, LLC ("PJM"), DEV is required to meet PJM's capacity obligation. SCC Staff's analysis shows that approximately 1,500 MWs of capacity will have to be constructed earlier than would otherwise be the case to replace the 4 retired units. DEV's customers essentially pay twice. First, they must pay for the 4 retired units for capacity that they will no longer receive due to RGGI. Secondly, they must pay for the costs of new capacity constructed sooner than otherwise necessary to replace these retired units.

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[1] Given that SCC Staff used a 25-year study period, this should be viewed as the average increase in the typical residential customer's monthly bill (averaged over the 25-year period in constant dollars). Thus, these bill impacts will likely be lower than $6.95 in the beginning of the study period and higher than that amount at the end of the study period. Measured in future inflated dollars, these average bill impacts will likely be greater than $6.95 over the 25-year period.

SCC STAFF ANALYSIS OF CUSTOMER BILL IMPACTS

OF VIRGINIA PARTICIPATING IN RGGI

February 21, 2019

Q. What is the SCC Staff's understanding of the Regional Greenhouse Gas Initiative ("RGGI")?

A. RGGI is a "cap and trade" market mechanism to cap and reduce CO_2 emissions from the electric power sector. It is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. The number of allowances, or "cap," is ratcheted down each year. Each of the RGGI member states is allocated the number of CO_2 emissions allowances corresponding to its share of the overall RGGI cap. Generally, each member state must submit its CO_2 emissions allowances for sale in the RGGI auction with the revenues received from these sales flowing back to each state. Fossil fuel electric power generators with a capacity of 25 megawatts ("MWs") or greater are required to hold allowances equal to their CO_2 emissions. The required offsetting CO_2 emissions allowances must be purchased by each fossil fuel generator. The Virginia Department of Environmental Quality ("DEQ") proposes to link to RGGI and its allowance auction system by way of a "consignment auction." Essentially, RGGI levies a carbon tax on fossil fuel generation, payable by electric generators in each RGGI state, with the goal of making fossil fuel generation less competitive, thus leading to reductions in fossil fuel generation and corresponding reductions in CO_2 emissions.

Q. What is the SCC Staff's understanding of DEQ's estimate of the bill impact on a typical residential customer under RGGI?

A. DEQ estimates that the typical monthly bill for a residential customer served by Dominion Energy Virginia ("DEV") will decrease by an average of $0.54 over the 2020-2030 time period. Given that RGGI is a government imposed cap and trade mechanism designed to impose additional costs on the use of fossil fuel generation, and given that DEV owns a significant portfolio of coal and natural gas generation units, the SCC Staff finds DEQ's projection of falling customer bills to be counterintuitive.

Q. Has the SCC Staff separately analyzed the cost and rate impacts of Virginia participating in RGGI?

A. Yes. SCC Staff estimates that RGGI will impose costs on DEV's customers. SCC Staff estimates that a typical monthly residential bill will see an average increase between $7 and $12, over the 2019-2043 time period, depending on whether Virginia *links* to RGGI or *joins* RGGI. SCC Staff estimates the total cost of linking to RGGI to be about $3.3 billion. SCC Staff estimates the total cost of joining RGGI to be about $5.9 billion.

Since DEQ's proposed RGGI rule envisions Virginia linking to RGGI, the remainder of this document will address the implications of Virginia linking to RGGI.[2]

Q. Why is the SCC Staff's bill impact of linking to RGGI higher than the bill impact calculated by DEQ?

A. As will be discussed in more detail later in this document, the most important difference between SCC Staff and DEQ is the market structure that was used in the modeling. DEQ modeled DEV as a deregulated utility and Virginia as a deregulated market. As a result, DEQ modeled DEV as if it was solely a purchaser of electricity from the grid. In contrast, SCC Staff modeled DEV's actual market structure as a vertically integrated utility that owns fossil fuel generation resources. SCC Staff correctly modeled DEV as both a purchaser of electricity from the grid and as a seller of electricity into the grid.

The deregulated market approach modeled by DEQ is consistent with the market structure that exists in all other RGGI member states except Vermont. It does not, however, reflect the market reality that exists in Virginia, and it is not appropriate to use this market structure to measure customer bill impacts of RGGI compliance for Virginians. Simply put, DEQ's model assumes that DEV does not own fossil fuel generation units that will be impacted by the new Virginia RGGI CO_2 regulations. However, DEV does own fossil fuel generation units and its customers will pay for the increased operating costs of the fossil fuel units that continue to run. Furthermore, DEV's customers will pay for these units whether the units are run or not.

[2] SCC Staff modeling assumed that if Virginia links to RGGI, 95% of the revenues received through the sale of CO_2 emissions allowances in the RGGI auctions would flow back to customers though the utilities to offset customer bill impacts. There are a variety of ways that emissions allowances revenues could serve to reduce DEV's customer bills. SCC Staff's analysis assumes that these revenues will benefit customers in one way or another.

Q. The 2018 Grid Transformation and Security Act ("2018 GTSA" or "SB966") contained several policy objectives[3] for DEV to potentially achieve by 2028 including: (1) the construction and/or purchase of 5,000 MWs of solar/wind generation capacity; (2) $870 million of proposed spending on energy efficiency programs; and (3) the construction of 30 MWs of battery storage. Will achieving these policy objectives alone result in DEV meeting its CO_2 emissions reductions targets under RGGI?

A. No. Determining the impact of 2018 GTSA policy goals must be done in the context of DEVs' membership and participation in the PJM Interconnection, LLC ("PJM") energy and capacity markets.[4]

PJM dispatches generation based on the economics of each individual unit. The addition of 5,000 MWs of solar/wind resources in Virginia, 30 MWs of battery storage, and $870 million of spending on energy efficiency will displace generation from the least efficient and highest cost generating units in the PJM footprint.[5] These units will most likely be aging coal and/or natural gas generating units. These fossil fuel generating units, while located within PJM, may or may not be in Virginia.[6] As a result, even if DEV achieves all of the 2018 GTSA's policy objectives described above, it may nevertheless be required to (i) prematurely retire currently operational coal generation units to meet RGGI CO_2 emissions reduction goals, and (ii) concurrently construct new natural gas fired generating units in order to meet its generation capacity obligation in PJM.

Q. Please provide the results of the SCC Staff's model simulations of Virginia linking to RGGI.

A. The SCC Staff's analysis[7] used the PLEXOS®[8] model to simulate several different scenarios as follows:

[3] SB966 also included the policy goals of grid modernization, the undergrounding of transmission lines, and the undergrounding of tap lines.
[4] PJM coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. For purposes of generation unit dispatch, the utilities in these states operate together as one large utility system.
[5] Likewise, the construction of renewable facilities or the implementation of energy efficiency measures in other PJM states may lead to less CO_2 emissions in Virginia.
[6] For example, the construction of additional solar facilities in Virginia may lead to the retirement of a coal unit in West Virginia or Ohio.
[7] DEV owns the PLEXOS® software and performed the model runs contained in this document at the direction of the SCC Staff.
[8] The PLEXOS® Integrated Energy model is a power market simulation software that uses mathematical programming and stochastic optimization techniques and is widely used by electric utilities including both DEV and Appalachian Power Company in Virginia.

1. A base scenario which represents a least cost plan for DEV to meet its customers' electricity requirements and that assumes that Virginia does not participate in RGGI;

2. A GTSA scenario in which the model is required to select the 5,000 MWs of solar/wind, 30 MWs of battery storage, and $870 million of energy efficiency contained in the 2018 GTSA and which also assumes that Virginia does not participate in RGGI; and

3. A GTSA-RGGI scenario in which the model is required to select the 5,000 MWs of solar/wind, 30 MWs of battery storage, and $870 million of energy efficiency contained in the 2018 GTSA and which also assumes that Virginia <u>links</u> to RGGI.

The model results showing the resulting DEV generating unit build plans and the net present value ("NPV") costs under each scenario are presented below:

	Base No RGGI		GTSA No RGGI		GTSA RGGI Link	
	Renewable MWs	Fossil MWs	Renewable MWs	Fossil MWs	Renewable MWs	Fossil MWs
2020	-	-	480	-	480	-
2021	80	-	491	-	491	-
2022	-	458	480	458	480	458
2023	-	458	480	458	480	458
2024	-	458	480	458	480	458
2025	-	458	480	-	480	458
2026	-	458	480	-	480	458
2027	-	458	480	-	480	458
2028	-	-	480	-	480	-
2029	-	458	480	-	480	458
2030	-	-	160	458	160	-
2031	-	-	-	-	-	-
2032	-	458	-	458	80	458
2033	-	458	-	-	480	-
Total	**80**	**4,122**	**4,971**	**2,290**	**5,531**	**3,664**
2034	480	-	-	458	-	458
2035	480	-	320	-	80	-
2036	160	-	-	458	-	458
2037	-	458	-	-	160	-
2038	160	-	-	458	-	-
2039	-	-	-	-	-	-
2040	-	458	-	458	-	-
2041	-	-	-	-	-	-
2042	-	458	-	458	-	-
2043	-	-	-	-	-	-
Total	**1,360**	**5,496**	**5,291**	**4,580**	**5,771**	**4,580**

NPV ($B)	**$26.75**	**$27.54**	**$29.95**

Q. What are the differences in the build plans under each scenario?

A. SCC Staff utilized a 25-year study period, which is the standard study period used by the State Corporation Commission ("Commission") to evaluate utility Integrated Resource Plans and utility applications for Certificates of Public Convenience and Necessity for the construction of utility proposed generation projects. In all three scenarios, the model selected the nuclear license extensions for the Surry and North Anna nuclear units on a cost optimization basis. All three scenarios under SCC Staff's modeling also include the retirements of all current cold reserve generating units[9] and Possum Point Unit 5. Under the GTSA-RGGI scenario, the additional retirements of Chesterfield Units 5 and 6 in 2022 and Clover Units 1 and 2 in 2025 are required as the added costs of purchasing the required offsetting CO_2 emissions allowances for these units make them uneconomic. The cost implications of these premature retirements will be discussed later in this document.

Q. Based on the SCC Staff's model results, what is the incremental cost of linking to RGGI?

A. Assuming the generation and energy efficiency related components contained in the 2018 GTSA are implemented, SCC Staff estimates that linking to RGGI will impose an incremental additional NPV cost of $2.41 billion[10] ($29.95 billion minus $27.54 billion) over the 25-year study period.

Q. How did the SCC Staff develop its estimate of a $7 typical residential customer bill impact for linking to RGGI?

A. First, SCC Staff developed a ratio of the NPV cost of the GTSA-No RGGI scenario divided by the NPV cost of the Base–No RGGI scenario. SCC Staff then applied this ratio to the base generation, generation rate adjustment clauses ("RACs"), and fuel factor portion of the current typical residential customer's monthly bill to determine the bill impact of the generation and energy efficiency-related components of the 2018 GTSA. SCC Staff estimates that the generation and energy efficiency-related components of the 2018 GTSA will increase the typical residential customer's monthly bill by $2.28 from $118.24 to $120.52.

SCC Staff then developed a ratio of the NPV cost of the GTSA-RGGI Link scenario divided by the NPV cost of the GTSA-No RGGI scenario. This ratio was applied to the

[9] The following units were placed in cold reserve status during 2018: Bellemeade 1, Bremo 3 & 4, Mecklenberg 1 & 2, Pittsylvania 1, Chesterfield 3 & 4, and Possum Point 3 & 4, representing 1,292 MW of generating capacity.
[10] This is equivalent to approximately $3.3 billion in nominal dollars.

base generation, generation RACs, and fuel factor components of the estimated typical residential customer's monthly bill described above for the generation and energy efficiency-related components 2018 GTSA. SCC Staff estimates that linking to RGGI will increase the typical residential customer's monthly bill by an average of $6.95 from $120.52 to $127.48 over the 25-year study period.[11]

Q. Identify the key assumptions the SCC Staff used in its RGGI bill analysis for DEV customers.

A. Some of the key assumptions are as follows:

- SCC Staff used a RGGI CO_2 emissions cap for Virginia of 28 million tons beginning in 2020 which decreases 3% per year through 2030, as proposed in Virginia State Air Pollution Control Board regulations currently under review.

- SCC Staff modeled DEV as the vertically integrated utility that it is, i.e., a utility that owns generation resources – and whose customers will pay for these units regardless of whether they are run or not;

- SCC Staff used the CO_2 emission containment reserve ("ECR") trigger price floor for CO_2 emission allowances published by RGGI;

- SCC Staff used a discount rate of 6.31%, which represents DEV's after tax weighted average cost of capital used in its most recent Integrated Resource Plan proceeding before the Commission; and

- SCC Staff assumed that 5,000 MWs of solar, 30 MWs of battery storage, and $870 million of spending on energy efficiency programs, consistent with the 2018 GTSA, are built or implemented.

- SCC Staff's analysis reflects the Commission's findings in its December 7, 2018 Order in Case No. PUR-2018-00065 regarding DEV's 2018 Integrated Resource Plan. Namely, Staff's analysis used: (1) the coincident peak PJM load and energy forecast scaled down to the DEV load serving entity level; and (2) a capacity factor of 23% for solar generating resources.

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[11] Given that SCC Staff used a 25-year study period, this should be viewed as the average increase in the typical residential customer's monthly bill (averaged over the 25-year period in constant dollars). Thus, these bill impacts will likely be lower than $6.95 in the beginning of the study period and higher than that amount at the end of the study period. Measured in future inflated dollars, these average bill impacts will likely be greater than $6.95 over the 25-year period.

Q. Why is the SCC Staff's bill impact of participating in RGGI higher than the bill impact calculated by DEQ?

A. SCC Staff's customer bill impacts showing an increase to customer bills significantly differs from DEQ's estimates of RGGI compliance resulting in lower customer bills. This is due to differing modeling assumptions. Some of DEQ's key assumptions are as follows:

- DEQ modeled DEV as if it were a deregulated utility that does not own generation resources operating in a deregulated competitive energy market. Thus, DEQ omitted the customer bill impact of increased fuel costs and prematurely retiring generating units and of additional costs to operate DEV's fossil fuel generating units that continue to run;

- DEQ used CO_2 emission allowance prices that are lower than the ECR trigger price for carbon emission allowances published by RGGI;

- DEQ used a discount rate of 2.1%;

- DEQ assumed that the generation and energy efficiency-related policy objectives contained in the 2018 GTSA are implemented.

The impact of these key DEQ assumptions is discussed below.

Q. What is the practical effect of DEQ using a CO_2 emission allowance price that is lower than the RGGI ECR trigger price floor for carbon emission allowances published by RGGI?

A. To the extent that the carbon emission allowance prices are lower, this will result in a lower cost estimate for RGGI compliance and lower typical bill impacts. A comparison of DEQ's CO_2 emission allowance prices, the RGGI ECR trigger price floor, and the RGGI CO_2 cost containment reserve ("CCR") trigger price ceiling is shown below.

	RGGI ECR Trigger Price Floor	RGGI CCR Trigger Price Ceiling	DEQ Price
2020	$6.00	$10.77	N/A
2021	$6.00	$13.00	N/A
2022	$6.42	$13.91	$4.01
2023	$6.87	$14.88	N/A
2024	$7.35	$15.92	N/A
2025	$7.86	$17.03	$4.55
2026	$8.41	$18.22	N/A
2027	$9.00	$19.50	N/A
2028	$9.63	$20.87	$5.18
2029	$10.30	$22.33	N/A
2030	$11.02	$23.89	$5.65

Q. Please explain why SCC Staff views the RGGI ECR trigger price as a floor and the RGGI CCR trigger price as a ceiling.

A. The RGGI ECR and CCR trigger prices establish a range of CO_2 emissions allowance prices which represent the policy goals of RGGI. These trigger prices should be viewed as a "soft" price floor and a "soft" price ceiling. Actual prices for CO_2 emissions allowances can clear at a price below the ECR trigger price or above the CCR trigger price in any given year. However, if the auction price clears below the ECR trigger price, RGGI will remove CO_2 emissions allowances from future auctions to force prices back above the ECR trigger price floor. Similarly, if the auction price clears above the CCR trigger price, then RGGI would inject additional CO_2 emissions allowances into the market to force prices back below the CCR trigger price ceiling.

Q. Does the SCC Staff view DEQ's assumed CO_2 emissions allowance prices to be too low?

A. Not necessarily. Historically, CO_2 emissions allowances have cleared the RGGI auction at relatively low prices. DEQ is assuming that this will continue to be the case in the future. In addition, as mentioned above, the RGGI market can clear at a price below the ECR trigger price. However, when estimating the costs of RGGI compliance going forward for Virginia, SCC Staff believes it is more realistic to use CO_2 emissions allowance prices that are consistent with RGGI's allowance price trigger mechanisms described above. SCC Staff used the ECR trigger price floor which SCC Staff views as being a conservative assumption.

Q. What is the practical effect of DEQ using a discount rate lower than DEV's weighted average cost of capital?

A. Using a lower discount rate understates the true costs of future capital investments. The Commission has consistently used DEV's weighted average cost of capital in evaluating CPCN applications for proposed generation and transmission projects. This is appropriate because it reflects DEV's actual costs of raising capital for these large capital projects.

Q. What is the practical effect of DEQ modeling DEV as if it were a deregulated utility that does not own generation resources operating in a deregulated competitive energy market?

A. Virginia is unique compared to the RGGI member states which are fully deregulated. Local Distribution Companies ("LDCs") in those deregulated states do not own generation assets. All generation is provided by merchant generators selling into the grid. All power consumed by the LDCs is purchased from the grid or through bilateral power purchase agreements with merchant generators.

In contrast, DEV is a vertically integrated utility that owns generation, transmission, and distribution resources. The LDCs in other RGGI states are purchasers of electricity from the grid. DEV is both a purchaser of electricity from the grid and a producer of electricity sold into the grid. DEV's ownership of generation resources is a key factor that must be considered in any RGGI analysis and it appears that DEQ did not fully consider this factor.

Q. Focusing on the impacts of RGGI on DEV as a purchaser of electricity, explain how DEQ calculated customer bill impacts.

A. DEQ calculates the incremental increase of PJM Interconnection, LLC ("PJM") power prices assuming that Virginia links to RGGI. DEQ then multiplies this incremental increase in cost per kilowatt-hour ("kWh") by the average monthly bill usage to arrive at the bill increase cost of RGGI compliance. DEQ then adjusts this bill impact by subtracting the expected pro-rata share of the RGGI CO_2 emissions allowance revenues that DEV will receive from the sale of CO_2 emissions allowances in the RGGI auction. It appears that DEQ's estimate of RGGI CO_2 emissions allowance revenues is greater than the increase in PJM power prices which results in DEQ's estimate of falling customer bills under RGGI.

Q. Does the SCC Staff agree that Virginia linking to RGGI will put upward pressure on PJM energy prices?

A. Yes. SCC Staff estimates that Virginia linking to RGGI will cause PJM power prices to increase by an average of $0.44 per megawatt hour ("MWh") over the 2020 to 2030 time period. Hourly PJM energy prices are determined by the marginal unit that clears the market each hour. The imposition of additional costs on Virginia fossil fuel units for the required offsetting CO_2 emissions allowances under RGGI will generally lead to higher cost marginal units setting the hourly PJM energy price, thus putting upward pressure on PJM energy prices.

Q. Does the SCC Staff agree that Virginia linking to RGGI will result in DEV receiving revenues from the sale of CO_2 emissions allowances into the RGGI auctions?

A. Yes, the table below shows SCC Staff's estimate of expected revenues from the sale of CO_2 emissions allowances. SCC Staff assumed that DEV would be allocated 70% of the Virginia total. SCC Staff further assumed that 5% of this total would go to the Virginia Department of Mines, Minerals and Energy ("DMME").[12]

[12] 5% of the revenues will go to DMME to defray the costs of oversight and implementation of Virginia's participation in RGGI.

	VA RGGI Carbon Cap (tons)	DEV Carbon Cap 70% of VA	DEV Cap @ 95% (tons)	RGGI ECR Prices	RGGI Allowance Revenues
	(a)	(b)	(c)	(d)	(e) = (c) x (d)
2020	28,000,000	19,600,000	18,620,000	$6.00	$111,720,000
2021	27,160,000	19,012,000	18,061,400	$6.00	$108,368,400
2022	26,320,000	18,424,000	17,502,800	$6.42	$112,367,976
2023	25,480,000	17,836,000	16,944,200	$6.87	$116,406,654
2024	24,640,000	17,248,000	16,385,600	$7.35	$120,434,160
2025	23,800,000	16,660,000	15,827,000	$7.86	$124,400,220
2026	22,960,000	16,072,000	15,268,400	$8.41	$128,407,244
2027	22,120,000	15,484,000	14,709,800	$9.00	$132,388,200
2028	21,280,000	14,896,000	14,151,200	$9.63	$136,276,056
2029	20,440,000	14,308,000	13,592,600	$10.30	$140,003,780
2030	19,600,000	13,720,000	13,034,000	$11.02	$143,634,680

Q. What is missing from DEQ's RGGI cost analysis?

A. As mentioned earlier, SCC Staff modeled DEV as a vertically integrated utility that owns a portfolio of fossil fuel generation resources. DEV is both a purchaser of power from the PJM market and a seller of power into the PJM market. DEQ's RGGI cost analysis does not include the costs of the CO_2 emissions allowances that DEV must purchase for each of its fossil fuel units. These costs will flow back to customers and increase customer bills. The cost of CO_2 emissions allowances will impact customers in two different ways.

First, many of DEV's fossil fuel units will continue to clear the PJM energy and capacity markets and will continue to run. However, given that these units will now have a higher unit dispatch cost, these units will return far less value back to the customer through the fuel factor.[13]

Secondly, Chesterfield Units 5 and 6 and Clover Units 1 and 2 are forced into retirement prematurely under SCC Staff's modeling. These units must be paid for by DEV's customers whether the units run or not.

[13] For a hypothetical example, if the unit dispatch cost for a fossil fuel unit is $30/MWh without RGGI and the PJM energy price is $33/MWh, then this unit will provide $3/MWh of value back to DEV's customers for every MWh sold into PJM. If the unit dispatch cost is increased to $32.50/MWh under RGGI reflecting the costs to the utility of the required offsetting CO_2 emissions allowances, then this unit will still run but it will now only provide $0.50/MWh of value back to the customer. The DEV fuel factor will increase to recover the $2.50/MWh of required RGGI costs under this hypothetical example.

Q. Why must customers pay for these prematurely retired units?

A. As a regulated utility, DEV has a legal obligation to provide service to every customer in its service area. When these units were approved for construction, they formed a necessary part of the generation "fleet" used to supply power to customers; thus, under the regulatory framework, the utility is entitled to recover the entire cost.

Q. What happens to the unrecovered costs of prematurely retired units in DEQ's analysis?

A. DEQ treated all generation units as merchant generators. As such, the shareholders of the entities that own the retiring fossil fuel unit would bear these unrecovered costs. Similarly, even for fossil fuel units that continue to run, DEQ's analysis assumes that the cost of the required offsetting CO_2 emissions allowances will be borne by the shareholders of the entities that own the affected fossil fuel generating units. That is, DEQ assumes that these shareholders will earn a lower profit as a result. In reality, since DEV owns the fossil fuel generating units, the cost of the required offsetting CO_2 emissions allowances will be collected from DEV's customers most likely through a higher fuel factor than would otherwise be the case.

Q. What are the costs that DEV will incur under RGGI for its fossil fuel units that will continue to run under RGGI?

A. SCC Staff estimated these costs to be the product of the expected CO_2 emissions (tons) for the GTSA-RGGI Link scenario and the ECR trigger price. This is presented in the table below.

	RGGI ECR Prices (a)	RGGI/GTSA DEV Carbon Output (tons) (b)	RGGI Allowance Costs (c) = (a) x (b)
2020	$6.00	26,488,641	158,931,846
2021	$6.00	25,240,860	151,445,160
2022	$6.42	25,715,612	165,094,229
2023	$6.87	25,617,605	175,992,946
2024	$7.35	24,970,901	183,536,122
2025	$7.86	24,767,813	194,675,010
2026	$8.41	24,441,398	205,552,157
2027	$9.00	26,013,263	234,119,367
2028	$9.63	22,956,099	221,067,233
2029	$10.30	24,424,271	251,569,991
2030	$11.02	22,877,523	252,110,303

Q. How would including the costs of CO_2 emissions allowances for DEV's fossil fuel units that will continue to run impact DEQ's RGGI cost analysis?

A. This is displayed in the table below.

	DEV Energy Consumed (MWh)	RGGI PJM Energy Price Increase ($/MWh)	Increased Cost of Purchased Energy	DEV RGGI Allowance Revenues	DEQ RGGI Cost Analysis	DEV RGGI Allowance Costs	SCC Staff RGGI Cost Analysis
	(a)	(b)	(c) = (a) x (b)	(d)	(e) = (c) - (d)	(f)	(g) = (c) - (d) + (f)
2020	88,217,000	$0.44	$38,534,790	$111,720,000	($73,185,210)	$158,931,846	$85,746,636
2021	88,602,520	$0.44	$38,703,192	$108,368,400	($69,665,208)	$151,445,160	$81,779,952
2022	89,374,730	$0.44	$39,040,507	$112,367,976	($73,327,469)	$165,094,229	$91,766,760
2023	89,917,040	$0.44	$39,277,398	$116,406,654	($77,129,256)	$175,992,946	$98,863,690
2024	90,556,640	$0.44	$39,556,787	$120,434,160	($80,877,373)	$183,536,122	$102,658,749
2025	90,793,260	$0.44	$39,660,147	$124,400,220	($84,740,073)	$194,675,010	$109,934,937
2026	91,353,920	$0.44	$39,905,053	$128,407,244	($88,502,191)	$205,552,157	$117,049,966
2027	92,017,840	$0.44	$40,195,066	$132,388,200	($92,193,134)	$234,119,367	$141,926,233
2028	93,082,110	$0.44	$40,659,958	$136,276,056	($95,616,098)	$221,067,233	$125,451,135
2029	94,001,280	$0.44	$41,061,468	$140,003,780	($98,942,312)	$251,569,991	$152,627,680
2030	94,927,940	$0.44	$41,466,250	$143,634,680	($102,168,430)	$252,110,303	$149,941,874

The table above is based on SCC Staff's RGGI model outputs for the GTSA-RGGI Link scenario. Applying DEQ's methodology shows a net cost reduction as the revenues received from the sale of CO_2 emissions allowances is greater than the increased cost of purchased power in all years. However, DEQ's methodology fails to include the required purchases of CO_2 emissions allowances to cover the CO_2 emissions from DEV's fossil fuel units that continue to run. SCC Staff's methodology includes those costs and results in a net cost increase in all years. The costs of the required CO_2 emissions allowances will increase the dispatch costs of DEV's fossil fuel units, which will cause these units to provide less value back to DEV's customers. This will be seen on customers' bills as an increase in the fuel factor. This increase in the fuel factor is captured in the SCC Staff's estimate of a $6.95 increase in the typical residential customer's bill.

It should be noted that DEQ's analysis stops at 2030 (11 years). However, RGGI will continue to impose costs beyond 2030. SCC Staff's analysis includes the costs of RGGI compliance over a 25-year study period, as discussed above.

It is important to note that the table above does <u>not</u> include the costs associated with DEV's fossil fuel units that are forced to retire prematurely nor the increased fuel costs from dispatch changes.

Q. What additional costs are imposed on DEV's customers from Chesterfield Units 5 and 6 and Clover Units 1 and 2 retiring prematurely?

A. SCC Staff's RGGI analysis shows that Chesterfield Units 5 and 6 and Clover Units 1 and 2 are forced into early retirement in 2022 and 2025, respectively. These 4 units have a combined capacity of nearly 1,500 MWs. These units are forced into retirement prematurely because the increase in their dispatch costs from including the costs of CO_2 emissions allowances under RGGI make them no longer competitive in the PJM power market.

Chesterfield Units 5 and 6 would retire in 2034 and 2039, respectively, without RGGI. Likewise, Clover Units 1 and 2 would retire in 2050 and 2051, respectively, without RGGI. Thus, RGGI will result in these units retiring between 12 and 26 years early.

The combined end of year 2018 net book value for DEV of these 4 units is $781 million.[14] The entire $781 million will be collected from DEV's customers.[15]

Furthermore, as a member of PJM, DEV is required to meet PJM's capacity obligation. SCC Staff's analysis shows that approximately 1,500 MWs of capacity will have to be constructed earlier than would otherwise be the case to replace the 4 retired units. Under the SCC Staff's modeling results, most of this will be natural gas-powered combustion turbine units (1,376 MWs), with the remainder being additional solar units (560 MWs nameplate).[16] SCC Staff estimates that this replacement capacity will cost approximately $1.3 billion, excluding financing costs and a profit margin. This investment will also be collected from DEV's customers.

[14] Chesterfield Units 5 and 6 have a net book value of $626,986,555. Clover Units 1 and 2 have a net book value of $307,710,398. DEV has a 50% ownership in Clover Units 1 and 2. The remaining 50%, or $153,855,199, is owned by ODEC. SCC Staff has not performed an analysis of the customer bill impacts on Electric Cooperative customers in Virginia due to the premature retirement of Clover Units 1 and 2.

[15] In addition, there are lost property taxes and lost jobs implications associated with these 4 units retiring prematurely. SCC Staff's analysis did not attempt to capture or quantify these impacts.

[16] 560 MWs of nameplate solar capacity translates into about 129 MWs for purposes of meeting the PJM capacity obligation.

DEV's customers essentially pay twice. First, they must pay for the capacity of the retired units for capacity that they will no longer receive due to RGGI. Secondly, they must pay for the costs of new capacity constructed sooner than otherwise necessary to replace these retired units.

The costs of the units required to replace the capacity of the prematurely retired units will most likely be recovered through future RAC's. These bill impacts of these new RACs are captured in the SCC Staff's estimate of a $6.95 increase in the typical residential customer's bill.