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Comments on regulation to reduce and cap carbon dioxide (CO_2) from fossil fuel fired electric power generating facilities by means of an interstate trading program (Revision C17)

Contents

Introduction and summary

Partnership for Policy Integrity (PFPI), the Appalachian Mountain Club, the Center for Biological Diversity, Dogwood Alliance, and Michelle's Earth Foundation appreciate the opportunity to comment on Virginia's plan to reduce and cap carbon dioxide (CO_2) from fossil fuel fired electric power generating facilities through an interstate trading program. Our comments focus on making Virginia's carbon trading program comprehensive and effective by urging the state to regulate emissions from all power sector facilities greater than 25 MW, including industrial facilities and facilities that burn solid biomass. Due to exemptions in the current draft plan for industrial, biomass, and waste-to-energy facilities, we estimate that up to 23 percent of the Commonwealth's carbon dioxide emissions from the energy sector would not be covered under the program. These gaps would create incentives to shift electric generation from regulated sources like coal and natural gas to potentially even higher-emitting sources of power like biomass that are not covered under the cap. Leaving these facilities uncovered by the plan will virtually ensure that they constitute an even larger proportion of the state's carbon and air pollution emissions in 2030, the plan's deadline date. Virginia should adopt a strategy for its carbon trading program that is comprehensive from inception.

Climate scientists say that we must reduce carbon dioxide emissions immediately and dramatically to avoid catastrophic climate change. There is no "do-over" – the time to take action is now.

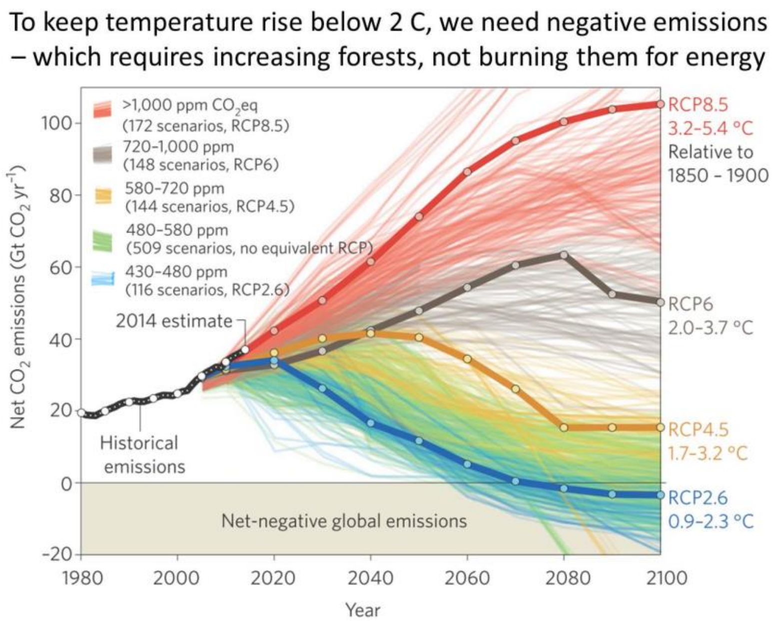


Figure 1. Global climate modeling projections[1] show that the only pathways to maintaining temperature rise below 2 C require steep and immediate reductions in CO_2 emission, followed by negative emissions – locking up CO_2 – consistent with significantly expanding forests, not burning them.

Virginia is particularly vulnerable to sea level rise caused by climate change among other climate change-related impacts. The state should not lose precious time in the effort to reduce emissions by exempting so many facilities from coverage under the cap. Virginia has an opportunity to get its carbon trading program right the first time, thus we recommend that Virginia cap stack emissions from all electric power sources greater than 25 megawatts. The state can credit facilities that employ combined heat and power (CHP), and can use a net emissions impact methodology, proposed below, to credit bioenergy emissions.

Background on Virginia's draft cap-and-trade plan

Virginia's draft plan seeks to cap and reduce carbon dioxide emissions from fossil fuel-based electric power plants with a nameplate capacity of at least 25 megawatts.[2] "'Fossil fuel-fired' means the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 10% of the annual heat input on a Btu basis during any year."[3] The plan aims to reduce emissions from covered plants by 30 percent (three percent per year) between 2020 and 2030 by issuing allowances for each ton of carbon dioxide emitted by a facility.[4] The company operating the facility must decide whether to reduce its pollution and sell additional allowances or buy additional allowances to cover the excess pollution. The program is designed to be compatible with the Regional Greenhouse Gas Initiative, a similar program in which nine northeastern states participate.[5] The current draft plan exempts fossil fueled power plants owned by an individual facility and located at the facility that produces electricity and heat primarily to operate the facility.[6] Under the proposed rule, facilities co-firing biomass with fossil fuels would need to purchase allowances for all the

CO_2 they emit. However, facilities that burn biomass and less than 10% fossil fuels are exempted from regulation.

Findings and recommendations

We analyzed Energy Information Administration (EIA) 2016 data on the fuels burned and energy generated from VA's power sector[7] and calculated CO_2 emissions using EIA emissions factors[8] for each fuel. We found that some of the biggest sources of CO_2 and conventional air pollution in Virginia are facilities that would not be covered under the current proposal. Exempting the industrial sector, biomass burners, and waste-to-energy plants would ignore a large proportion of VA's energy sector emissions.

Virginia should cover all power facilities greater than 25 MW under the cap

To achieve effective reductions in the state's carbon emissions, and to administer the program fairly, Virginia should cover all plants greater than 25 MW under the cap, including industrial facilities that generate heat and power, standalone bioenergy plants and waste-to-energy plants in the utility sector. This policy would reduce CO_2 emissions more effectively, remove incentives to re-fire fossil plants with biomass, and help reduce emissions of air pollution at some of the most polluting plants in Virginia, producing significant co-benefits for health and the environment. The financial impact of air pollution is well demonstrated; EPA's risk analysis for the Clean Power Plan showed monetized benefits associated with reduced emissions of CO_2 exposure to PM_2 and ozone of $11 billion to $51 billion by 2025.[9]

Table 1 shows the EIA data on emissions; we added a column, "Excl," to show the plants that we presume would be excluded from regulation because EIA has designated them as biomass burners, waste-to-energy plants, or in the industrial sector. The presumably excluded plants are indicated in the column by acronyms showing the type of fuel they burn or whether they are industrial facilities: "Bio" (biomass), "WTE" (waste-to-energy), "Ind" (industrial). We did not have access to data on plant capacity, only on net generation, so we were not able to determine which plants would escape regulation by virtue of being less than 25 MW in capacity. The table also shows the percent of total 2016 power sector emissions contributed by each plant. "State-level fuel increment" represents cumulative emissions from facilities that are too small to trigger EIA's specific reporting requirements. The data show that Virginia's energy sector emitted about 49.1 million tons in 2016. About 11.3 million tons, or 23 percent, was emitted by plants classified as biomass (4 percent), industrial (16 percent), or waste-to-energy (3 percent). (Some proportion of these emissions would not be covered due to facilities being smaller than 25 MW).

Table 1. Plants recorded by EIA as generating electricity in Virginia in 2016. Total CO_2 emissions differ from electric generation emissions at CHP plants. The contribution of each plant's emissions to total power sector CO_2 is noted in the last column.

Excl	Plant Name	EIA Sec #	Sec Name	CHP?	Operator Name	Tot CO2 (tons)	Elec CO2 (tons)	% tot
	Chesterfield	1	Electric Utility	N	Virginia Electric & Power Co	7,669,843	7,669,843	15.6%
	Clover	1	Electric Utility	N	Virginia Electric & Power Co	5,644,923	5,644,923	11.5%
	Virginia City Hybrid Energy Center	1	Electric Utility	N	Virginia Electric & Power Co	3,582,002	3,582,002	7.3%
	Warren County	1	Electric Utility	N	Virginia Electric & Power Co	3,441,714	3,441,714	7.0%
Ind	Covington Facility	7	Industrial NAICS Cogen	Y	MeadWestvaco Corp	3,379,950	498,950	6.9%
	Brunswick County Power Station	1	Electric Utility	N	Virginia Electric & Power Co	2,528,670	2,528,670	5.1%
	Doswell Energy Center	2	NAICS-22 Non-Cogen	N	Doswell Ltd Partnership	2,220,798	2,220,798	4.5%
	Tenaska Virginia Generating Station	2	NAICS-22 Non-Cogen	N	Tenaska Virginia Partners LP	2,189,464	2,189,464	4.5%
Ind	State-Fuel Level Increment	7	Industrial NAICS Cogen	Y	State-Fuel Level Increment	1,983,815	243,132	4.0%
Ind	WestRock-West Point Mill	7	Industrial NAICS Cogen	Y	WestRock-West Point Mill	1,623,133	265,172	3.3%
	Possum Point	1	Electric Utility	N	Virginia Electric & Power Co	1,564,413	1,564,413	3.2%
	Bear Garden	1	Electric Utility	N	Virginia Electric & Power Co	1,438,583	1,438,583	2.9%
WTE	Covanta Fairfax Energy	2	NAICS-22 Non-Cogen	N	Covanta Fairfax Inc	996,894	996,894	2.0%
	Spruance Genco LLC	3	NAICS-22 Cogen	Y	Spruance Genco LLC	859,747	172,512	1.8%
Ind	International Paper Franklin Mill	7	Industrial NAICS Cogen	Y	International Paper	691,779	119,592	1.4%
	Hopewell Cogeneration	3	NAICS-22 Cogen	Y	GDF Suez NA - Hopewell	652,889	592,399	1.3%
WTE	Wheelabrator Portsmouth	5	Commercial NAICS Cogen	Y	Wheelabrator Environmental Systems	640,817	279,890	1.3%
	State-Fuel Level Increment	2	NAICS-22 Non-Cogen	N	State-Fuel Level Increment	567,769	567,769	1.2%
	Yorktown	1	Electric Utility	N	Virginia Electric & Power Co	534,334	534,334	1.1%
	Birchwood Power	2	NAICS-22 Non-Cogen	N	Birchwood Power Partners LP	495,984	495,984	1.0%
Bio	Hopewell Power Station	1	Electric Utility	N	Virginia Electric & Power Co	484,978	484,978	1.0%
	Bellmeade Power Station	1	Electric Utility	N	Virginia Electric & Power Co	478,681	478,681	1.0%
Bio	Southampton Power Station	1	Electric Utility	Y	Virginia Electric & Power Co	466,376	373,480	0.9%
	Ladysmith	1	Electric Utility	N	Virginia Electric & Power Co	447,572	447,572	0.9%
Bio	Altavista Power Station	1	Electric Utility	N	Virginia Electric & Power Co	442,011	442,011	0.9%

Table 1, continued.

Excl	Plant Name	EIA Sec #	Sec Name	CHP?	Operator Name	Tot CO2 (tons)	Elec CO2 (tons)	% tot
	Gordonsville Energy LP	1	Electric Utility	N	Virginia Electric & Power Co	438,994	438,994	0.9%
	State-Fuel Level Increment	3	NAICS-22 Cogen	Y	State-Fuel Level Increment	401,700	57,475	0.8%
	Remington	1	Electric Utility	N	Virginia Electric & Power Co	395,648	395,648	0.8%
	Mecklenburg Power Station	1	Electric Utility	N	Virginia Electric & Power Co	375,515	375,515	0.8%
	Marsh Run Generation Facility	1	Electric Utility	N	Old Dominion Electric Coop	350,249	350,249	0.7%
	State-Fuel Level Increment	4	Commercial NAICS Non-Cogen	N	State-Fuel Level Increment	348,203	348,203	0.7%
Bio	Halifax County Biomass	2	NAICS-22 Non-Cogen	N	South Boston Energy LLC	292,439	292,439	0.6%
Bio	Multitrade of Pittsylvania LP	1	Electric Utility	N	Virginia Electric & Power Co	263,212	263,212	0.5%
	Bremo Bluff	1	Electric Utility	N	Virginia Electric & Power Co	253,401	253,401	0.5%
	Louisa Generation Facility	1	Electric Utility	N	Old Dominion Electric Coop	249,050	249,050	0.5%
	Clinch River	1	Electric Utility	N	Appalachian Power Co	203,120	203,120	0.4%
	State-Fuel Level Increment	5	Commercial NAICS Cogen	Y	State-Fuel Level Increment	110,325	22,582	0.2%
	Elizabeth River Power Station	1	Electric Utility	N	Virginia Electric & Power Co	109,163	109,163	0.2%
	Gravel Neck	1	Electric Utility	N	Virginia Electric & Power Co	105,409	105,409	0.2%
	Commonwealth Chesapeake	2	NAICS-22 Non-Cogen	N	Commonwealth Chesapeake Co LLC	82,925	82,925	0.2%
	Wolf Hills Energy	2	NAICS-22 Non-Cogen	N	Middle River Power II, LLC	65,753	65,753	0.1%
	Darbytown	1	Electric Utility	N	Virginia Electric & Power Co	28,828	28,828	0.1%
	State-Fuel Level Increment	1	Electric Utility	N	State-Fuel Level Increment	6,143	6,143	0.0%
Ind	State-Fuel Level Increment	6	Industrial NAICS Non-Cogen	N	State-Fuel Level Increment	2,177	2,177	0.0%
	Chesapeake	1	Electric Utility	N	Virginia Electric & Power Co	229	229	0.0%
	1st Energy	1	Electric Utility	N	Virginia Electric & Power Co	-	-	0.0%
	Bath County	1	Electric Utility	N	Virginia Electric & Power Co	-	-	0.0%
	Eastern Shore Solar, LLC	2	NAICS-22 Non-Cogen	N	Dominion Renewable Energy	-	-	0.0%
	John H Kerr	1	Electric Utility	N	USCE-Wilmington District	-	-	0.0%
	North Anna	1	Electric Utility	N	Virginia Electric & Power Co	-	-	0.0%
	Smith Mountain	1	Electric Utility	N	Appalachian Power Co	-	-	0.0%
	Surry	1	Electric Utility	N	Virginia Electric & Power Co	-	-	0.0%

Industrial facilities should be regulated under the cap

DEQ has asked for input on whether the plan should cover industrial facilities. To make the plan fair and effective, we believe the answer is yes. Industrial power plants are a significant source of CO_2 in Virginia. As a whole, the industrial sector emitted 16 percent of power sector CO_2 in the state in 2016 (Table 2).

Table 2. The contribution of each sector to total and electric generation CO_2 emissions in Virginia, 2016.

EIA Sector Number	Sector Name	Total CO2 (tons)	Elec CO2 (tons)
1	Electric Utility	31,503,061	31,410,165
2	NAICS-22 Non-Cogen	6,912,026	6,912,026
3	NAICS-22 Cogen	1,914,336	822,386
4	Commercial NAICS Non-Cogen	348,203	348,203
5	Commercial NAICS Cogen	751,142	302,472
6	Industrial NAICS Non-Cogen	2,177	2,177
7	Industrial NAICS Cogen	7,678,678	1,126,846
	sum	**49,109,623**	**40,924,275**

Total emissions from industrial and non-industral faciities

non-industrial sum	41,428,768	39,795,252
industrial sum	7,680,855	1,129,023

Perentage of total emissions from industrial and non-industrial facilities

non-industrial %	84%	97%
industrial %	16%	3%

As currently proposed, the plan would specifically exclude from regulation some of the biggest polluters in Virginia. For instance, the WestRock Covington plant would presumably be exempted under the industrial exemption as a plant that generates on-site heat and power. This facility is recorded by EIA as burning natural gas, bituminous coal, distillate fuel oil, residual fuel oil, black liquor, and wood, and was responsible for 7% of VA's power sector CO_2 emissions in 2016 (emissions were even higher in 2015, as the plant burned nearly 1.2 million tons of wood that year, higher than in 2016). The company brought a new 75 MW wood-fueled generator online in 2013, which led to a dramatic increase in wood consumption and emissions (Figure 2). The facility is a large source of conventional pollution, and has recently been penalized by EPA for excessive particulate matter emissions.[10]

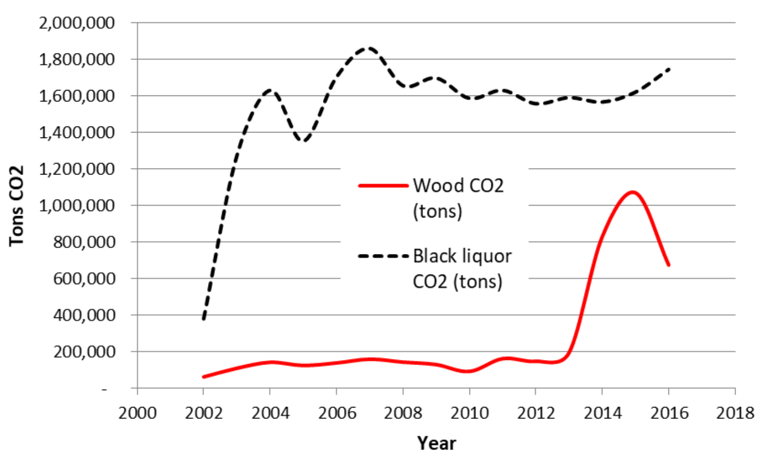


Figure 2. CO_2 emissions from wood and black liquor burning at the WestRock Covington facility.

Similarly, the WestRock West Point mill is recorded as burning coal, black liquor, distillate fuel oil, natural gas, residual fuel oil, sludge waste, and wood solids in 2016. It was responsible for 3.3% of the state's CO_2 emissions (Table 1) but as an industrial burner would be exempted under the proposed rule, as would be the International Paper Franklin mill, which emitted about 700,000 tons of CO_2 from black liquor and natural gas in 2016.

Utility biomass plants should be regulated under the cap

Virginia has several dedicated biomass-fueled power plants, thus the proposed plan's failure to cover these facilities will exempt a significant amount of CO_2 pollution from coverage, and, like the industrial exemption, give a free pass to some of the largest sources of air pollution in the state. The 50 MW Halifax County South Boston plant is a standalone facility. While the plant is shown as burning less than 300,000 tons of wood in 2016, its capacity is upwards of 600,000 tons.[11] The plant has been recently subject to consent decrees for air quality violations.[12] Dominion Energy operates one of the largest biomass power stations in the United States, the 83 MW Pittsylvania station, and recently converted three nearly mothballed coal plants to burn biomass at Altavista, Hopewell, and Southampton, for a total of about 153 MW. Initial construction permits for the facilities reveal that their combined permitted emissions annually were 253.2 tpy of $PM_{2.5}$, 114.6 tpy sulfur dioxide, 1,237 tpy nitrogen oxides, 2,748 tpy carbon monoxide, and 129.4 tpy volatile organic compounds. Dominion also built the 585-megawatt Virginia City plant to burn up to 20 percent wood with 80 percent fossil fuels; this facility would need to purchase allowances for biomass-derived CO_2 under the plan. The plan also apparently exempts plants that generate electricity by burning municipal waste, a portion of which is considered biogenic. Combined, biomass burned in Virginia facilities emitted over 8 million tons of CO_2 in 2016; the non-biogenic portion of municipal waste emitted another 1 million tons. However, under Virginia's draft cap-and-trade plan, only about 2.5 percent of this CO_2 would be recognized and regulated under the cap – the approximately 230,000 tons emitted by co-firing biomass at Dominion's Virginia City Hybrid plant.

Why it is important to regulate biomass plants under Virginia's plan

Covering biomass plants under Virginia's carbon plan will dramatically increase the plan's effectiveness because it will regulate what is currently a large source of CO_2, and remove an incentive for fossil-fired plants to re-fire with biomass. Burning solid biomass undermines efforts to reduce emissions, in part because biomass fuels inherently emit a large amount of CO_2 per unit energy. The following chart is derived from VA's 2016 emissions data and shows the EIA fuel emissions factors per unit fuel energy content. The top three highest-emitting categories of solid fuel per unit energy (lb/MMBtu) are biomass.

Table 3. EIA ranking of emissions per MMBtu heat input for various fuels and their contribution to total and electric generation CO_2 emissions in Virginia, 2016.

Fuel code	Fuel	lb/MMBtu	Total CO2	Electric CO2
OBS	other biomass solids	233	11,226	1,509
BLQ	black liquor	222	3,785,418	597,021
WDS	wood solids	207	3,595,979	2,302,422
BIT	bituminous coal	206	19,451,445	17,254,908
MSB	biogenic muni waste	200	999,984	816,431
MSN	non-biogenic muni waste	200	964,192	787,837
SLW	sludge waste	185	13,482	2,203
DFO	distillate fuel oil	163	285,760	277,071
RFO	residual fuel oil	163	210,288	202,645
LFG	landfill gas	130	508,705	508,705
OBG	other biomass gases	127	2,177	2,177
NG	natural gas	117	19,280,967	18,171,345

These data are expressed on a heat-input basis (pounds of CO_2 per million Btu of energy inherent in the fuel). When fuels are burned in a power plant, the efficiency of conversion of fuel to energy affects the CO_2 emission rate on an output basis (lb CO_2 per MWh). Wood-burning power plants are extraordinarily inefficient, in part because wood tends to have a high moisture content. This further increases the greenhouse gas impact of bioenergy. For instance, Table 4 shows EIA data on a coal plant and three biomass plants – Dominion's Altavista plant (getting an assist with some natural gas to assist wood-burning), their Pittsylvania plant, and the brand-new South Boston Halifax plant. The two older biomass plants are highly inefficient, and all three fall far short of the efficiency of Dominion's Clover coal plant from the mid-1990's, which is 34 percent efficient with an assist from some distillate fuel oil (newer coal plants can achieve even higher efficiencies).

Table 4. Facility efficiency for three biomass plants and a coal plant, calculated based on fuel heat input and net generation. CO_2 emissions are also shown.

Fuel	Plant Name	Operator Name	Fuel code	Elec fuel (MMBtu)	Net generation (MWh)	elec CO2	efficiency
	Altavista Power Station	Virginia Electric & Power Co	NG	18,526	1,215	1,083	
Biomass	Altavista Power Station	Virginia Electric & Power Co	WDS	4,264,296	281,462	440,928	23%
Biomass	Multitrade of Pittsylvania LP	Virginia Electric & Power Co	WDS	2,545,568	146,658	263,212	20%
Biomass	Halifax County Biomass	South Boston Energy LLC	WDS	2,828,229	208,730	292,439	25%
	Clover	Virginia Electric & Power Co	DFO	80,129	7,931	6,543	
Coal	Clover	Virginia Electric & Power Co	BIT	54,762,819	5,436,987	5,638,380	34%

To illustrate how this inefficiency translates to high CO_2 emissions per MWh, Figure 3 compares 2016 data from two Dominion plants: the Chesterfield plant, which has several burners combusting coal, oil, and gas, and the Pittsylvania plant, which burns wood. The wood-burners's stack emissions are 170 percent those of the coal burner at the Chesterfield plant, and 414 percent those of the natural gas burner.

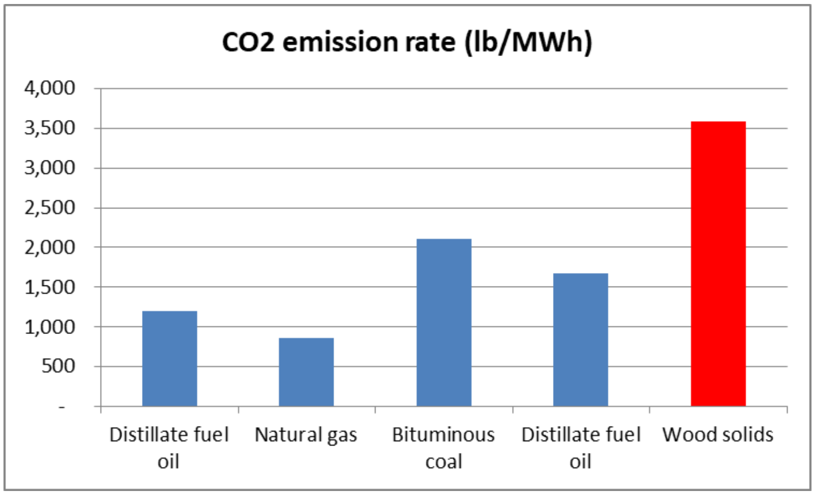


Figure 3. CO_2 emission rate for the wood-fired boiler at the Pittsylvania plant, versus emission rates for different fuels at the Chesterfield plant.

We support DEQ's decision to include emissions from co-fired biomass under the cap. The high moisture content of biomass co-fired with fossil fuels can decrease the efficiency of the facility overall, meaning that it emits more CO_2 per unit energy not only from the biomass, but from co-fired fossil fuels as well. There are numerous reports of degradation in efficiency for coal plants co-firing biomass, though results vary depending on biomass moisture content and composition.[13] Southern Company reported for co-firing where switchgrass replaced 5 percent of coal, "boiler efficiency has been found to be somewhat less than for coal-alone operation."[14] A report from the Electric Power Research Institute (EPRI)[15] states that cofiring "virtually always reduces the power plant boiler efficiency," though reductions can be "managed as an economic issue." A USDA summary provides data on decreases in efficiency at a number of US cofiring operations.[16]

Debunking claims about treatment of bioenergy as "carbon neutral"

The fact that DEQ has proposed to fully count stack emissions from biomass co-firing with no exemption for "eligible" biomass that has been "sustainably harvested" suggests that the Agency may see through the various arguments in favor of bioenergy carbon neutrality made by biomass proponents. Nonetheless, it is worth exploring some of these arguments, because they are so pervasive. It is particularly important to examine claims by Dominion.

In early comments to DEQ on the carbon plan, Dominion claimed the following:

"*In 2013, Dominion made significant investments to converted (sic) three 51 MW units that used coal to 100% biomass, encouraged by EPA's prior determination that biomass was carbon neutral for PSD permitting. Close proximity to an ample supply of waste wood biomass as well as EPA's "carbon-neutral" policy for permitting under the PSD effective at that time were key economic drivers for these projects. Given Dominion's significant investment in renewable wood waste and forest residuals biomass, it is important for our customers that biomass emissions be considered carbon neutral*."

This statement highlights how treating bioenergy as having zero emissions serves as a powerful incentive for more tree-burning power plants. Beyond that, however, it contains several inaccuracies.

First, Dominion did not convert three "51 MW units that used coal." The units were 63 MW[17] and the boiler de-rating that occurred with the conversion to biomass downgraded the units to 51 MW.

Second, it is not true that EPA had made a "prior determination that biomass was carbon neutral" when the Dominion plants were permitted. When EPA initially began regulating power plant CO_2 under the federal Clean Air Act's Prevention of Significant Deterioration (PSD) permitting program in early 2011, biomass power plants were regulated alongside fossil fueled power plants - all the CO_2 was counted. In July 2011, EPA suspended regulation of CO_2 from bioenergy facilities under the PSD program for a period of three years and convened a Panel of its Science Advisory Board (SAB) to advise the agency on how to regulate biogenic CO_2 emissions. The EPA had not determined that bioenergy was "carbon neutral" – it explicitly admitted the topic required study, while suspending regulation. The suspension was immediately challenged, however, and in 2013 a federal court ruling vacated EPA's regulatory deferral for biogenic CO_2 emissions (*Center for Biological Diversity v. EPA*, D.C. Cir. No. 11-1101, July 12, 2013). The court identified *nothing* in the Clean Air Act that would allow EPA to exempt biogenic CO_2 from being counted when determining whether a facility meets the emissions thresholds that trigger PSD permitting.[18]

The permit for Dominion's first conversion, of the Altavista plant, is dated May 22, 2012 – prior to the ruling but concurrent with the court case. Dominion knew that EPA had not concluded that bioenergy was "carbon neutral" and knew there was a possibility that plants would be regulated in the future. Further confirming that Dominion knew the status of bioenergy greenhouse gas permitting was indeterminate, the company submitted comments on March 26, 2012 to the EPA Science Advisory Panel charged with determining how bioenergy emissions should be counted. In those comments, Dominion requests that the Science Panel make an "*a priori*" determination that biomass is carbon neutral. (In fact, the panel later went out of their way to say the exact opposite, perhaps in response to this very letter, stating in the report biomass is **not** *a priori* carbon neutral.) The issue was still in play in 2014, when EPA published the New Source Performance Standards for greenhouse gas emissions in the federal register (January 8, 2014).[19] The NSPS both acknowledges the importance of feedstocks for net carbon impacts and conclusion of the panel that biomass cannot be considered *a priori* carbon neutral (emphasis added):

"*Issues related to accounting for biogenic CO2 emissions from stationary sources are currently being evaluated by the EPA through its development of an Accounting Framework for Biogenic CO2 Emissions from Stationary Sources (Accounting Framework). In general,* ***the overall net atmospheric loading of CO2 resulting from the use of a biogenic feedstock by a stationary source, such as an EGU, will ultimately depend on the stationary source process and the type of feedstock used, as well as the conditions under which that feedstock is grown and harvested****. In September 2011, the EPA submitted a draft of the Accounting Framework to the Science Advisory Board (SAB) Biogenic Carbon Emissions (BCE) Panel for peer review. The SAB BCE Panel delivered its Peer Review Advisory to the EPA on September 28, 2012.82. In its Advisory, the SAB recommended revisions to the EPA's proposed accounting approach, and also noted that* ***biomass cannot be considered carbon neutral a priori, without an evaluation of the carbon cycle effects related to the use of the type of biomass being considered****."*

Notably, a 2013 article[20] in Power Engineering by Paul Ruppert, a senior vice president at Dominion, mentions several reasons for the coal plant conversions, even stating "Benefits to the environment would include reductions in nitrogen oxides, sulfur dioxide, particulate matter and mercury" – but nowhere mentions a reduction in carbon dioxide emissions as a rationale. Perhaps this claim represented a bridge too far for this particular executive; perhaps he was aware of the skepticism that met Dominion's claims about bioenergy at the Virginia State Corporation Commission (SCC) when the company applied to convert the plants. In its application and 2011 testimony to the SCC supporting the biomass conversions,[21] Dominion made numerous claims regarding biopower. A notable exchange occurred between a Dominion witness and a Commissioner:

> COMMISSIONER CHRISTIE: Before you leave that. This has always fascinated me. Walk me through again -
> THE WITNESS: Yes.
> COMMISSIONER CHRISTIE: -- why a commodity that when you burn it produces twice as much carbon as coal is considered carbon neutral. Just walk me through that again.

The witness then went on to describe that residues would decompose in 10 to 15 years, or 25 years for large logs, and that burning these residues should therefore be considered carbon neutral.[22] While this argument might be valid if Dominion's converted coal plants operated for a single year and then shut down, for facilities in continuous operation, the net cumulative atmospheric CO_2 loading over this period would be many millions of tons more than if the residues had simply decomposed, as we demonstrate below.

Dominion and other bioenergy proponents also like to argue that as long as forest growth exceeds harvesting, that burning wood should be considered as having zero emissions. This is a common definition of "sustainable" harvesting, though there is no standard definition of the term. Even under the industry's terms, however, this argument is erroneous. To understand why, consider that forests are like a bank for carbon dioxide. Growing one ton of forest wood takes just over one ton of CO_2 out of the atmosphere, adding it to the bank's total deposits. Likewise, burning one ton of wood emits one ton of CO_2, withdrawing it from the bank and adding it to the atmosphere. When forests are cut and burned for electricity or heat, the forest bank's deposits are smaller than they would have been if the trees had been left standing, and there is more carbon dioxide in the atmosphere. When the bioenergy industry claims that current forest growth should be considered as offsetting bioenergy emissions, the bioenergy industry is effectively arguing that the bank's deposits can be transferred from one customer's account to another to cover up for the fact that some customers have withdrawn their money. This violates a simple physical concept, that mass must be conserved. As the Intergovernmental Panel on Climate Change (IPCC) states, "*If bioenergy production is to generate a net reduction in emissions, it must do so by offsetting those emissions through* ***increased*** *net carbon uptake of biota and soils*"[23] (emphasis added).

The biomass industry also likes to argue that the Intergovernmental Panel on Climate Change treats bioenergy as carbon neutral. This is not the case. The IPCC greenhouse gas reporting protocols count carbon loss from bioenergy in the land-use sector, when trees are harvested, and thus to avoid double-counting, does not count it in the energy sector – not at all the same as treating it as having zero emissions. The false representation of this position has become so pervasive, the IPCC was compelled to state, "*The IPCC approach of not including bioenergy emissions in the Energy Sector total should not be interpreted as a conclusion about the sustainability or carbon neutrality of bioenergy*."[24]

Policy precedent for counting bioenergy emissions

DEQ's decision to count biomass emissions from co-firing without an exemption for "eligible" biomass is a sensible step that should be extended to cover emissions from utility sector and industrial sector bioenergy emissions. Adding these plants would require raising the cap but should not entail other difficulties; the plants would simply increase the number of units covered, and should not interfere with the program's ability to interface with RGGI. Policy precedents for counting biomass carbon exist elsewhere. Massachusetts ended renewable energy subsidies for utility-scale wood-burning power plants in 2012,[25] based on the results of the state-commissioned Manomet Study,[26] which found it would take multiple decades to offset CO_2 emitted by biomass power plants, thus conflicting with the state's goals of reducing power sector emissions. The District of Columbia enacted a similar law in 2015.[27] Policymakers given the opportunity to examine the science around bioenergy carbon accounting tend to withdraw their support for bioenergy; for instance in Vermont, the Public Service Board denied a Certificate of Public Good to a proposed biomass plant, concluding after filings that "*the evidentiary record supports a finding that the Project would release as much as 448,714 tons of CO2e per year, and that sequestration of those greenhouse gases would not occur until future years, possibly not for decades, and would not occur at all in the case of forest-regeneration failures*."[28] As a result, the plant was not built.

Virginia has an opportunity to adopt a strategy that avoids the mistakes of previous carbon trading programs. Treatment of bioenergy as having zero emissions under the European Union's carbon trading program has led to explosive growth of the wood pellet industry in the US Southeast, including in Virginia. Forests, including bottomland hardwood wetlands that represent some of the most carbon-rich and biodiverse ecosystems in the US, are being clear-cut for biomass fuel. The UK is waking up to the damage its policies are causing, and also to the fact that bioenergy doesn't actually reduce emissions. A recent document from the UK's Department of Business, Energy, and Industrial Strategy admitted in a discussion of bioenergy that "*other renewable generation technologies have matured to the point where they can be deployed reliably at large scale, and they are becoming increasingly affordable. When compared with these technologies, **carbon savings from biomass conversion or co-firing are low or non-existent**, and the cost of any savings is high*"[29] (emphasis added). As stated in an op-ed titled "Burning wood on an industrial scale is daft," by a Member of Parliament Tommy Sheppard,

"Who's kidding who? Just because the carbon in wood pellets isn't fossilised doesn't mean the carbon dioxide you get when it burns isn't really carbon dioxide.

"The argument that this is carbon neutral because the trees absorbed an equal amount of carbon dioxide while they were growing has got to be one of the stupidest I've ever heard. You might as well say that some fossil fuels are carbon neutral because they're made out of plants which absorbed carbon dioxide a million years ago.

"To be carbon neutral, an equal amount of CO_2 needs to be taken out of atmosphere as is released into it over the same period of time. Even fast-growing trees take many years to photosynthesise carbon dioxide into wood. If you can't see that incinerating the same tree in a matter of seconds adds to CO_2 levels in today's atmosphere, then you're not thinking about this hard enough."[30]

A proposal for weighting bioenergy emissions in Virginia's carbon trading program

DEQ has gone part of the way toward regulating bioenergy emissions by proposing that co-fired facilities be required to hold allowances for 100% of the CO_2 they emit, whether it be from biomass or fossil fuels. We particularly appreciate that DEQ has not repeated the mistakes of the Regional Greenhouse Gas Initiative program in allowing "eligible" biomass to be treated as having zero emissions when it is co-fired in electric plants and defining eligible biomass as "sustainably harvested" wood. As stated above, "sustainably harvested" is a largely undefined term and is not meaningful for carbon accounting.

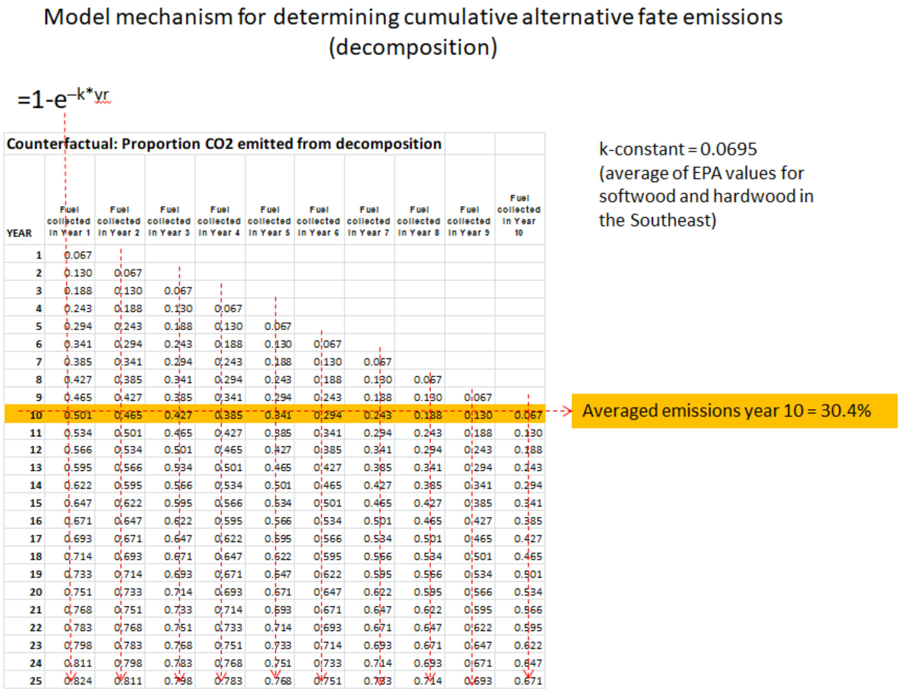
However, it is important for DEQ to cover all plants under the cap, including those that primarily or exclusively burn biomass. We believe that accomplishing this might be facilitated by counting bioenergy *net* emissions under the carbon plan, rather than stack emissions. Net emissions are a cumulative measure assessed over some time period, and represent the difference between stack emissions and emissions if the biomass underwent some alternative fate.

There are four basic categories of wood-derived biomass that are defined by the alternative fate if the material is not burned in a power plant:

1. trees that if not used for fuel would continue growing, or be harvested for some other purpose;
2. forestry residues that would otherwise remain onsite to decompose, or in limited cases would be burned for disposal;
3. mill residues that would be incinerated for disposal even if not burned for energy (black liquor, some sawdust and other wood);
4. mill residues that can be used for other purposes like mulch, animal bedding, and particle board.

This framework matches in part Dominion's argument about forestry residues that "*Unless re-purposed for other uses, such as energy production, this material is often left on-site after a harvesting operation is completed and will eventually be burned on-site or nearby, or will decompose, releasing carbon into the atmosphere and turned into organic matter on the forest floor and soil*."[31] What is different is that we show that the emissions from burning residues for energy are significantly greater than those from decomposition over decades, and thus net emissions – the *difference* between "stack" emissions and alternative fate emissions – should be regulated under Virginia's carbon trading program.

Figure 4 shows the mechanism for calculating decomposition emissions. Wood cut in each year is assumed to follow a course of decomposition determined by an averaged decomposition rate for Virginia's forests, and the cumulative proportion of potential emissions at any point, in this case year 10, corresponding to the carbon plan's 2030 target date, can be calculated as the averaged emissions up to that point.



Counterfactual: Proportion CO2 emitted from decomposition

YEAR	Fuel collected in Year 1	Fuel collected in Year 2	Fuel collected in Year 3	Fuel collected in Year 4	Fuel collected in Year 5	Fuel collected in Year 6	Fuel collected in Year 7	Fuel collected in Year 8	Fuel collected in Year 9	Fuel collected in Year 10
1	0.067									
2	0.130	0.067								
3	0.188	0.130	0.067							
4	0.243	0.188	0.130	0.067						
5	0.294	0.243	0.188	0.130	0.067					
6	0.341	0.294	0.243	0.188	0.130	0.067				
7	0.385	0.341	0.294	0.243	0.188	0.130	0.067			
8	0.427	0.385	0.341	0.294	0.243	0.188	0.130	0.067		
9	0.465	0.427	0.385	0.341	0.294	0.243	0.188	0.130	0.067	
10	0.501	0.465	0.427	0.385	0.341	0.294	0.243	0.188	0.130	0.067
11	0.534	0.501	0.465	0.427	0.385	0.341	0.294	0.243	0.188	0.130
12	0.566	0.534	0.501	0.465	0.427	0.385	0.341	0.294	0.243	0.188
13	0.595	0.566	0.534	0.501	0.465	0.427	0.385	0.341	0.294	0.243
14	0.622	0.595	0.566	0.534	0.501	0.465	0.427	0.385	0.341	0.294
15	0.647	0.622	0.595	0.566	0.534	0.501	0.465	0.427	0.385	0.341
16	0.671	0.647	0.622	0.595	0.566	0.534	0.501	0.465	0.427	0.385
17	0.693	0.671	0.647	0.622	0.595	0.566	0.534	0.501	0.465	0.427
18	0.714	0.693	0.671	0.647	0.622	0.595	0.566	0.534	0.501	0.465
19	0.733	0.714	0.693	0.671	0.647	0.622	0.595	0.566	0.534	0.501
20	0.751	0.733	0.714	0.693	0.671	0.647	0.622	0.595	0.566	0.534
21	0.768	0.751	0.733	0.714	0.693	0.671	0.647	0.622	0.595	0.566
22	0.783	0.768	0.751	0.733	0.714	0.693	0.671	0.647	0.622	0.595
23	0.798	0.783	0.768	0.751	0.733	0.714	0.693	0.671	0.647	0.622
24	0.811	0.798	0.783	0.768	0.751	0.733	0.714	0.693	0.671	0.647
25	0.824	0.811	0.798	0.783	0.768	0.751	0.733	0.714	0.693	0.671

Figure 4. A section of the excel model that calculates emissions for forestry residues and other biomass fuels where the alternative fate is decomposition.

Visually, this looks like a slice through a series of curves:

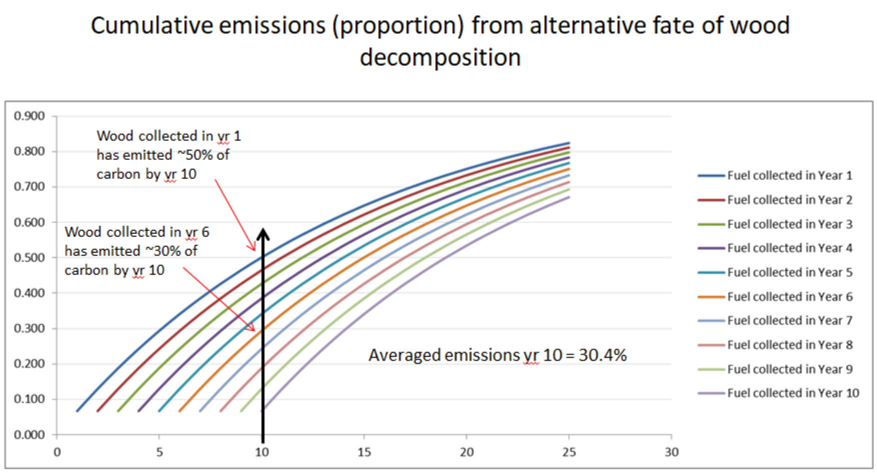


Figure 5. Graphical representation of the emissions shown in Figure 4.

These alternative fate emissions are subtracted from the "direct" emissions of biomass combustion to calculate the net additional CO_2 that was emitted by burning the wood rather than letting it decompose.

The following example assumes one ton of wood is burned each year for ten years; the alternative fate decomposition emissions are also calculated over ten years. (Burning one ton of wood at typical moisture content of 45 percent emits just over one ton of CO_2, so wood burned and CO_2 are functionally equivalent).

Calculation of net emissions and
Net Emissions Impact (NEI)

$$\overset{\text{7 tons}}{\text{Net } CO_2} = \overset{\text{10 yrs x 1 ton/yr = 10 tons}}{\text{direct } CO_2} - \overset{\text{30\% of 10 tons = 3 tons}}{\text{alternative fate } CO_2}$$

$$\text{NEI} = \frac{\text{net } CO_2}{\text{direct } CO_2} \qquad \text{7 tons} \div \text{10 tons} = 70\%$$

Figure 6. Worked example of net emissions and the net emissions impact (NEI) for a case where one ton of wood is burned for energy each year, versus being allowed to decompose. The alternative fate emissions taken from Figure 4 are subtracted from the direct combustion emissions to calculate net emissions.

The NEI at year 10 is 70%, meaning that 70% of the direct stack emissions represent a net increase of CO_2 loading to the atmosphere over that time period. Applying this figure to the carbon trading situation would mean that facilities burning forestry residues would be obligated to purchase 0.7 allowances for every ton of CO_2 they emitted. However, for facilities burning black liquor or other materials where the alternative fate was unquestionably incineration without energy recovery, the net difference between direct emissions (combustion) and alternative fate emissions (also combustion) is zero, meaning the facility would be obligated to purchase zero allowances for the carbon it emits. Since many industrial facilities burn black liquor and other mill residues that may arguably be incinerated if not burned for energy, this provides an “industrial exemption” in the Virginia carbon trading program, but one that is based on a scientific and explainable rationale, rather than an arbitrary exemption.

We support counting carbon dioxide emissions at the stack as the best way to account for carbon dioxide emissions from industrial, waste-to-energy, and biomass facilities. Counting stack emissions is a closer approximation of the net atmospheric impact to which EPA referred in the NSPS than the assumption that emissions are zero, which is the functional outcome of not regulating wood-burning power plants under the cap. Stack emissions are further an underestimate of the actual net carbon impact of cutting and burning whole trees that would have otherwise continued growing and removing CO_2 from the atmosphere.[32] However, as a secondary option, we support the NEI methodology because it is relatively simple, science-based, and would ensure that some emissions are counted even if companies claim to use residues and, in fact, use whole trees. It would also provide an “intelligent” industrial exemption for facilities that burn materials where the alternative fate is genuinely incineration. Regulating these facilities is important because they can be very large sources of both fossil fuel and biogenic CO_2, and need the same incentives as the rest of the power sector to reduce emissions.

A proposal for incentivizing combined heat and power (CHP) plants under the cap

CHP plants contributed 22 percent of Virginia's power sector CO_2 in 2016, and electric-only plants emitted 78 percent. Most CHP plants are in the industrial sector; those not designated as industrial include Hopewell Cogeneration (a different plant than the Hopewell biomass burner owned by Dominion); Spruance Genco LLC, a coal-burner; and the Southampton biomass power station owned by Dominion, which reported a total heat input of 25 percent greater than its heat input for electricity only. This plant received 4 percent of its heat input from distillate fuel oil in 2016.

The existence of cogeneration plants outside the industrial sector suggests that DEQ will need to find a way to accommodate these facilities in the carbon trading program even if the industrial exemption is maintained. However, we recognize DEQ's dilemma in not wanting to overregulate CHP. Promoting CHP is helpful if it leads to genuine reductions in fuel burning. To effectively and meaningfully incentivize use of CHP, DEQ should ensure the carbon trading plan covers CHP plants, but provide a reduction in allowance obligations based on generation of useful thermal energy, as EPA proposed in the Clean Power Plan. It is not advisable to simply exempt CHP plants from the carbon trading program for at least two reasons. First, some plants may claim to operate as CHP plants, but not generate a meaningful amount of "useful" thermal energy, and exempting CHP plants could incentivize this kind of cheating. Second, many industrial sector CHP plants burn a variety of dirty and inefficient fuels and are extremely polluting. Subjecting these plants to carbon trading program will ensure that they, like electricity-only plants, seek to minimize emissions and generate energy where possible from zero-emissions technologies.

We appreciate the opportunity to submit comments and are happy to answer any questions.

Sincerely,

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