ASSESSING THE GHG IMPACT OF BENEFICIAL ELECTRIFICATION IN VERMONT

ABSTRACT

Vermont's electric power portfolio (generation and purchases) has the lowest carbon intensity of any U.S. state. How Vermont regulators and state agencies calculate GHG emissions from electricity currently follow EPA and IPCC protocols, but is incomplete since "pre-generation" emissions (fuel-cycle) are not considered. Part 1 of this paper addresses ways that a fuller and more consistent perspective on electric emissions could supplement our current inventory. Part 2 of the paper addresses the fact that our current estimates of emissions due to future load growth are often incorrect and understate the GHG reduction potential of beneficial electrification. Forecasting electric emissions over time (using a long-run marginal emission rate) is necessary to reflect how Vermont's and the regional electric grid are evolving and will become less carbon intensive. It is also necessary to measure emissions on an hourly basis to understand the time-based impacts of new electric loads such as heat pumps and electric vehicles.

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Beneficial electrification refers to investing in high-efficiency electric heating/cooling systems and electric vehicles to replace ones that rely on more expensive and polluting fossil fuels. A well designed state policy of beneficial electrification can reduce greenhouse gas (GHG) emissions, reduce consumer costs, and help mitigate health impacts of burning fossil fuels. The two primary examples, most important to Vermont, are replacing fossil fuel heating appliances with cold-climate heat pumps and replacing internal combustion engine (ICE) vehicles with all electric vehicles (AEVs).

Understanding beneficial electrification's impacts on existing emissions is extremely important for crafting state policy going forward. While there is general agreement that heat pumps and AEVs can reduce emissions significantly over their fossil fuel counterparts, there is not consensus on methodologies for assessing the GHG emissions from electric generating sources. This leads to competing arguments about the effectiveness of beneficial electrification and hampers development of effective and consistent state policy.

Measuring GHG Emissions from Electricity

VT's current GHG inventory methodology (referred to in this paper as the "Inventory" to distinguish it from other methodologies used for Tier III, efficiency reporting, or other programs) relies on protocols established by the U.S. Environmental Protection Agency (EPA) and Intergovernmental Panel on Climate Change (IPCC), and also recommendations from the 2007 study for the Governor's Commission on Climate Change that laid out the first comprehensive inventory of GHG emissions.[1] Based on these recommendations, the Department of Environmental Conservation (DEC), which is in charge of VT's annual inventory, currently only considers the emissions directly produced by a generation facility, not "pre-generation emissions" (fuel processing, transport, and methane leakage), or life-cycle emissions based on the construction, operation, and eventual decommissioning GHG impacts of a plant. Based on this, the DEC currently assigns a zero emission factor to all hydro, wind, and solar plants (which do not combust fuel but do have on-going emissions) and also to nuclear power plants (which do not release carbon directly from generation but have very carbon intensive fuel processes).

VT's electricity comes from many generation sources that use different fuel types. Decades of forward-thinking state policy, regulation, and innovative efforts by utilities have led to VT having the lowest electric sector carbon emissions of any state in the nation (based on utility in-state generating resources and contract purchases). Figure 1 shows VT's 2020 physical generation sources before Renewable Energy Certificate (REC) transactions are accounted for. This table also shows emissions by source or fuel type based on current DEC inventory methodology.

[1] *Final Vermont Greenhouse Gas Inventory and Reference Case Projections, 1990-2030,* Center for Climate Strategies, September 2007

Figure 1. Current VT GHG Electric Emission Rates[2]

	VT 2020 Physical Generation & Purchases (Pre-REC Accounting)			
Generation Source	TOTAL MWh 2020	% of Total MWh	GHG kg CO2e/MWH	2020 GHG kg CO2e
Biomass	395,481	7.3%	27	10,761,381
Farm Methane	15,233	0.3%	0	-
HQ System Mix	1,363,015	25.3%	0	-
Hydropower (NE & NY)	752,311	13.9%	0	-
Landfill Methane	103,193	1.9%	0	-
Solar	512,419	9.5%	0	-
Wind	616,092	11.4%	0	-
Natural Gas (VT Peaker)	1,588	0.0%	413	655,502
Nuclear	1,494,389	27.7%	0	-
Oil - (VT Peaker)	16,390	0.3%	1002	16,427,008
System Mix (ISO-NE)	126,391	2.3%	288	36,400,726
TOTAL PURCHASES	5,396,503	100.00%		64,244,617
TOTAL RETAIL SALES	5,299,539			
kg CO2e/MWH				**12**
RE Total	3,757,744	70%		
Non RE Total	1,638,758	30%		

Of note is that under VT's current GHG accounting protocols, the state's contractual purchases and in-state generation (physical electricity delivered) is over twenty times cleaner (12 kg CO2e/MWH) than the regional (ISO-NE) "system mix", which had an average carbon intensity of 288 kg CO2e/MWH in 2020.[3]

The reason for this is clear - ISO-NE's generation is dominated by fossil gas plants, whereas VT's electrical portfolio relies mainly on hydro and nuclear low-carbon resources as shown below in Figure 2.

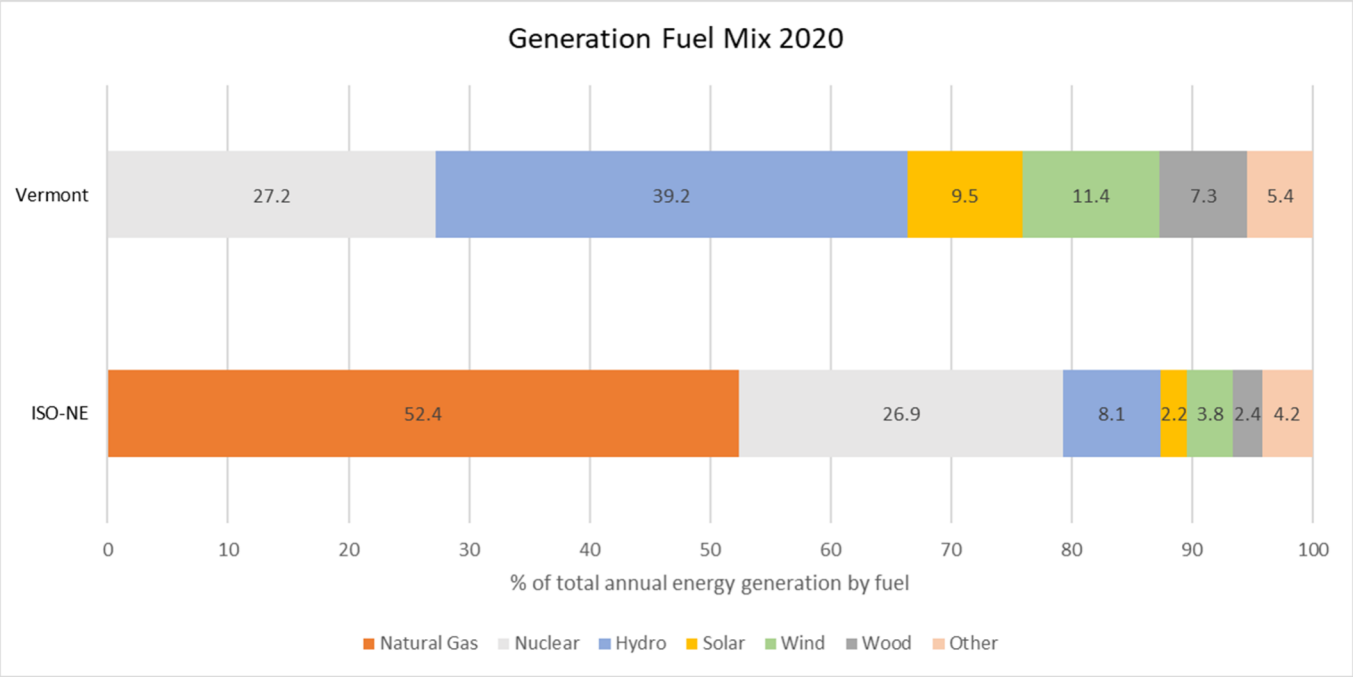
Note: In this paper, GHG emissions are expressed in kilograms CO2e per megawatt-hour of energy. This is also equivalent to grams per kilowatt hour. CO2e is "carbon dioxide equivalent" which include all three major greenhouse gases – carbon dioxide (CO2), methane (CH4), and nitrous oxides (NOx) added together at their 100-year global warming potential (GWP100).

[2] *Energy Action Network*, research by L.W. Seddon

- Based on 2020 MWH generation & utility data from the VT Public Service Department;
- HQ is considered 100% renewable under VT RES. Actual RE generation percentage is certified at 99%; GHG emissions assumed to be zero under current ANR GHG inventory methodology. Most recent research (see footnote #6) indicates operational GHG emissions of 24 kg/MWH;
- ISO-NE mix was 16% renewable in 2020, excluding refuse burning plants, but VT RES accounting classifies the system mix as all non-renewable since RECs are not held by VT utilities;
- Solar, wind, and hydro assumed to emit zero GHG under current "inventory" methodology.

[3] *ISO-NE 2020 Generator Air Emission Report*, April 2022, page 4, includes NY & Canadian imports.

Figure 2. Comparison of VT and ISO-NE Generation Mix[4]



An emissions analysis that accounts for both the pre-generation and direct combustion emissions of electricity generation provided to Vermont could be a useful supplement to the existing DEC inventory methodology. Such an analysis would provide a more comprehensive understanding of the full operational emissions of the existing electricity generation infrastructure (from both fossil, nuclear, and renewable generators) and inform analysis of proposals for new investments in generation, transmission, and storage.

The Cambium Model developed by the National Renewable Energy Laboratory (NREL) uses this methodology to include both "pre-combustion" and "combustion" emissions. NREL researchers are using Cambium to model hourly emissions, costs, and operational data for the U.S. electric grid.[5] This model starts in 2020 and forecasts hourly data year by year to 2050 in order to model the evolution of the U.S. grid, changes in generation technology, and future emissions.

As noted, the Cambium Model includes pre-generation emissions (which the authors call "pre-combustion") for both fossil fuel, nuclear, and renewable generators. This is important for measuring the actual GHG footprint of the regional system grid (ISO-NE), which is heavily dependent on fossil gas generation, but also important for considering the emissions from Hydro Quebec (HQ) and nuclear contracts which made up 53% of VT's electricity purchases in 2020.

[4] 2020 data from ISO-NE and VT Department of Public Service

[5] *Cambium Model Documentation,* Gagnon et al, NREL, 2021. See also the online NREL Cambium Viewer at https://scenarioviewer.nrel.gov/

The latest research on the HQ system estimates that CO2e emissions from HQ due to operations and greenhouse gases (primarily methane) released from flooded reservoirs are on the order of 24 kg CO2e/MWH.[6]

Research on pre-generation emissions from ISO-NE fossil gas plants, which are due to fossil gas extraction and methane leakage from pipelines, indicates their CO2e impact adds about 20% to estimates that are based on just direct combustion emissions.[7]

VT also relies on a significant amount of nuclear power (about 25% of overall portfolio) from contracts with both Seabrook (NH) and Millstone (CT) nuclear plants. The Cambium Model research indicates nuclear power generation has CO2e emissions of about 9 kg/MWH due to pre-generation (fuel processing) emissions.

As shown in Figure 3 below, **if GHG values from this latest research are used to account for the full operational emissions due to a generation facility, VT's average electricity GHG emissions rise to 24 kg CO2e/MWH. This is double the current DEC estimates (done by EPA/IPCC methodology) but still over ten times lower than the ISO-NE regional system mix.**

Figure 3. Pre-generation + Combustion emission accounting

	VT 2020 Physical Generation & Purchases (Pre-REC Accounting)			
Generation Source	TOTAL MWh 2020	% of Total MWh	GHG kg CO2e/MWH	2020 GHG kg CO2e
Biomass	395,481	7.3%	33	13,173,464
Farm Methane	15,233	0.3%	0	-
HQ System Mix	1,363,015	25.3%	24	32,371,604
Hydropower (NE & NY)	752,311	13.9%	0	-
Landfill Methane	103,193	1.9%	0	-
Solar	512,419	9.5%	0	-
Wind	616,092	11.4%	0	-
Natural Gas (VT Peaker)	1,588	0.0%	422	670,276
Nuclear	1,494,389	27.7%	9	13,225,342
Oil - (VT Peaker)	16,390	0.3%	919	15,060,627
System Mix (ISO-NE)	126,391	2.3%	404	51,062,129
TOTAL PURCHASES	5,396,503	100.00%		125,563,441
TOTAL RETAIL SALES	5,299,539			
kg CO2e/MWH				**24**
RE Total	3,757,744	70%		
Non RE Total	1,638,758	30%		

[6] *Improving the accuracy of electricity carbon footprint: Estimation of hydroelectric reservoir greenhouse gas emissions*, Levasseur et al, Renewable and Sustainable Energy Reviews, 2021

[7] *Life-cycle Greenhouse Gas Emissions from Electric Generation, NREL/FS-6A50-80580* September 2021

A final approach to calculating GHG emissions from power plants is a complete life-cycle approach which considers emissions from plant construction, fuel extraction and processing, combustion, on-going operations and maintenance, and decommissioning at the end of a facility's useful life.

The VT Climate Council (VCC) has recommended such an approach as a supplemental GHG accounting for all fuels, not just electricity:

While Vermont continues to update the GHG Inventory, supplemental accounting and further research and data gathering is also called for. Specifically, the Vermont Climate Council and State of Vermont should gather information to allow for supplemental upstream and/or lifecycle accounting of emissions related to the use of energy in Vermont, including those emissions that occur outside the boundaries of the state, as called for in section 578(a) of the GWSA. Future upstream and/or lifecycle accounting is envisioned to stand alongside—but not replace— the current in-boundary GHG inventory.

A recently released RFP by the Agency of Natural Resources seeks to have a life-cycle methodology and life-cycle GHG analysis of energy use in VT completed in time for inclusion as a supplement to the DEC's 2023 GHG Inventory.

This new and supplemental analysis is intended to function as a decision aid, helping to inform future updates to the state's Climate Action Plan (CAP), and ultimately to ensure that Vermont achieves a fuller understanding of the greenhouse gas emissions that Vermont can fairly be understood to be responsible for and options for reducing such emissions.

This will be very important research and should offer new insights into Vermont's actual GHG "footprint" and how to assess the GHG impact of all fuels in a comparable way. But the field of life-cycle assessment (LCA) is relatively young and faces many challenges such as using differing system boundaries, inconsistent characterizations of technologies, and use of different impact assessment frameworks. As a result, LCA estimates by researchers can vary a hundred-fold for the same technology.

To help create an accurate and accepted range for life-cycle assessments, NREL has been working on the "harmonization" of LCA estimates since 2012. After reviewing over 3,000 LCA research reports, subjecting them to three further rounds of peer review, and selecting only the papers (about 15%) that meet standards for quality and transparency, NREL has published median LCA emissions estimates for most generation technologies. The most recent update of this research (2021) is shown below in Figure 4.

Figure 4.

Median Published Life Cycle Emissions Factors for Electricity Generation Technologies, by Life Cycle Phase

	Generation Technology	One-Time Upstream	Ongoing Combustion	Ongoing Non Combustion	One-Time Downstream	Total Life Cycle	Sources
Renewable	Biomass	NR	—	NR	NR	52	EPRI 2013 Renewable Electricity Futures Study 2012
	Photovoltaic[a]	~28	—	~10	~5	43	Kim et al. 2012 Hsu et al. 2012 NREL 2012
	Concentrating Solar Power[b]	20	—	10	0.53	28	Burkhardt et al. 2012
	Geothermal	15	—	6.9	0.12	37	Eberle et al. 2017
	Hydropower	6.2	—	1.9	0.004	21	DOE 2016
	Ocean	NR	—	NR	NR	8	IPCC 2011
	Wind[c]	12	—	0.74	0.34	13	DOE 2015
Storage	Pumped-storage hydropower	3.0	—	1.8	0.07	7.4	DOE 2016
	Lithium-ion battery	32	—	NR	3.4	33	Nicholson et al. 2021
	Hydrogen fuel cell	27	—	2.5	1.9	38	Khan et al. 2005
Nonrenewable	Nuclear[d]	2.0	—	12	0.7	13	Warner and Heath 2012
	Natural gas	0.8	389	71	0.02	486	O'Donoughue et al. 2013
	Oil	NR	NR	NR	NR	840	IPCC 2011
	Coal	<5	1010	10	<5	1001	Whitaker et al. 2012

Values are in grams of carbon dioxide equivalent per kilowatt-hour (g CO2e/kWh) NREL/FS-6A50-80580 Sep 2021

While these results are important and certainly interesting, there are several caveats about LCA accounting that need to be recognized before applying this "cradle to grave" method to Vermont's GHG supplemental assessments.

Since LCA includes GHG emissions from construction, which for existing plants occurred in the past, it is important to distinguish between existing facilities and those yet to be built. GHG construction emissions from existing plants are now unavoidable and are not affected by whether a state or utility buys power from them or not. Since a primary purpose of GHG accounting is to understand the future impact of power purchase decisions, including these "sunk" GHG emissions may result in inappropriate conclusions regarding the overall GHG impact of purchases or investments. While this issue of "sunk" or unavoidable emissions can theoretically be handled by modifying existing LCA estimates, it would require extensive research into LCA estimates and methods.

LCA research also tends to rely on generalized averages of plants either nationwide or worldwide. Often specific research better quantifies emissions from a particular facility or

power system, and thus it makes sense to use that. A case in point, would be hydropower, whose emissions are highly specific to type of plant and location. NREL's harmonized estimate of all hydropower has an on-going GHG emission rate of 1.9 kg CO2e/MWH. But specific research into the HQ system (Levasseur 2021), which is characterized by northern boreal reservoirs that have significant methane emissions, indicates a life-cycle "operational only" emissions rate of 24 kg CO2e/MWH.[8] Even on a full life-cycle basis including construction and decommissioning, the NREL's harmonized median result (21 kg/MWH) is very different from Levasseur's median HQ LCA estimate of 34.5 kg/MWH.

While understanding these different methodologies and viewpoints is important, it still does not change the fundamental conclusion that Vermont's electricity portfolio has the lowest carbon intensity in the nation. Adding pre-generation emission factors (fuel cycle and fugitive emissions) to the proposed supplemental inventory assessments is definitely a way to enhance accuracy and transparency to the accounting of electrical generation emissions. Doing full life-cycle accounting, when accurate information is available, may also provide additional information useful to future Public Utility Commission (PUC) regulatory decisions concerning utility planning and investments.

REC Accounting

The issue of "REC accounting" often comes up when trying to assign a GHG emission number to electricity purchases. Renewable Energy Certificates (also called Credits) track the MWH generated each quarter by renewable generators. RECs come in various "classes" relating to the renewable attributes of a generation source – what technology, fuel type, and when the plant was built. These quarterly credits are bought and sold in various state markets in the ISO-NE region, allowing utilities to meet their state's particular renewable portfolio standard (RPS).

Since RECs define the renewable nature of a generator, they also *indirectly* relate to the emissions of a plant, but they do not necessarily measure actual GHG emissions of a plant. RECs are tracked by ISO-NE and recorded in the New England Power Pool (NEPOOL) GIS database which includes all generation. This database is used by state and federal agencies for their inventories of electrical generation.

RECs can be "bundled" as part of a power purchase contract and accompany delivered energy to a utility. They can also be "unbundled" from power deliveries, transferring legal ownership of renewable MWHs to a utility that is not actually receiving the power. The energy generation associated with unbundled RECs must be physically capable of being delivered to the ISO-NE system, which helps assure that the region as a whole meets its

[8] Ibid footnote 6. This value excludes emissions from construction of facilities but does include ongoing emissions from reservoirs and operations.

combined renewability targets. In this manner, RECs create a regional market that allows utilities to meet their state's RPS requirements in a least cost manner.

The issue of "additionality" is often raised as an argument against the use of RECs in GHG accounting. Since RECs (of different classes and monetary value) cover both existing renewable plants and additions of new renewable generators, the argument is made that REC markets and the resulting trading of RECs from older plants can actually delay the investment in new renewables that are necessary to meet our climate goals. This argument confuses the purpose of RECs and conflates their impact with the goals of additionality built into state RPS policies (such as VT's Tier II requirements).

According to the Center for Resource Solutions, "RECs deliver renewable energy generation and the associated emissions, and in doing so, reduce GHG footprints. Project additionality is not necessary to convey use of renewable generation or to assign emissions to particular consumers. Neither is additionality necessary for RECs to provide a market signal for more renewable and zero-emitting energy".

It is true that the RPS rules concerning state GHG reduction goals, required additionality, and the classification of RECs vary from state to state within in the ISO-NE region. This non-uniformity of policy can lead to different and sometimes conflicting regional goals. **These conflicts may slow down the coordinated effort to jointly lower the carbon footprint of the ISO-NE grid, but it is generally understood that the REC market helps protect the continuing operation of existing renewable plants and also sends a market signal to build additional renewables.**

Despite this state to state non-alignment, all New England states must use the NEPOOL GIS database and RECs to identify individual generators when assessing a facility's GHG emissions to avoid double or under counting. In Vermont, this leads to a "post-REC" electric portfolio that is heavily dominated by low-cost, unbundled hydro RECs from Canada and New England. Figure 5 shows the breakdown of VT's 2020 electricity by fuel type based on RECs that have been reported by each utility.[9]

[9] Based on information provided by the VT Public Service Department for the 2020 RES compliance report. GHG emission rates include "pre-combustion" estimates.

Figure 5. VT 2020 Post-REC Generation & Emissions

	VT 2020 Electricity Purchases (Post-REC Accounting)			
Generation Source	RECs/MWH 2020	% of Total Sales	GHG kg CO2e/MWH	2020 GHG kg CO2e
Biomass	196	0.0%	33	6,468
Farm Methane	21	0.0%	0	-
HQ System Mix	2,316,995	43.7%	24	55,607,880
Hydropower (NE & NY)	1,296,923	24.5%	0	-
Solar	140,858	2.7%	0	-
Wind	171,398	3.2%	0	-
Total RECs (renewable)	3,926,391	74%		55,614,348
Nuclear	1,385,382	26%	9	12,468,438
TOTAL RETAIL SALES	5,299,539			68,082,786
kg CO2e/MWH				**12.85**

Based on 2020 REC reporting, VT's electricity was 74% renewable (as a percentage of sales). **Applying both pre-generation and combustion GHG emissions rates, this post-REC accounting of VT's electricity indicates an average of 13 kg CO2e/MWH, or a little over one-half the emissions of VT's physical electricity deliveries (24 kg CO2e/MWH)** using the same pre and post-combustion methodology as shown in Figure 3.

While the emissions from VT's electricity sector (both pre-REC and post-REC) are already very low, they are expected to decline further as utilities meet VT's Renewable Energy Standard (RES) requirements (currently requiring 75% renewable electricity by 2032, but that may be adjusted upward by the VT Legislature). Already several utilities (Burlington Electric Department, Swanton Electric, and Washington Electric Cooperative) have reached the 100% renewable threshold based on post-REC accounting.

Given VT's current low-carbon electricity portfolio and the likelihood of further reductions due to the buildout of solar with battery storage and off-shore wind, it is reasonable to expect that VT's electricity will be at least 95% carbon-free by 2030.

But this future low-carbon grid is not always reflected in estimates of the GHG impact of load growth due to beneficial electrification. While the latest modeling (LEAP 2021 for the VCC) does attempts to more accurately reflect VT's actual portfolio, other forecasts sometime still assume that new loads will be powered by the current "marginal ISO-NE generators", those generators that are brought on-line during periods of increased or high demand. Since this marginal generation is currently dominated by fossil gas plants, ISO-NE's 2020 average marginal emission rate was 428 kg CO2e/MWH. Applying this emission rate to new load growth grossly overstates the future emissions due to beneficial electrification.

Measuring GHG Impact of New Electric Loads

To fully understand the impact of adding new electric loads to offset fossil fuel use, it is necessary to consider several key metrics:

1. What is the operating life of the measure? A heat pump may last and operate for 15 years, so it is necessary to calculate its GHG impact over its entire operating life as our electric portfolio and its associated emissions change.
2. What is the hourly load profile of a device? Since GHG emissions vary by hour of the day and month, the impact of consuming electricity at midnight (when there is excess hydro capacity) is much different than at peak demand times, such as 7am or 7pm, when that extra load may require purchases of fossil gas peaking power.
3. What is the actual hourly GHG profile of the utility serving the new load and how will this hourly profile change over time?

As we know, VT's portfolio is much less carbon intensive than ISO-NE's and will continue to get cleaner over time, yet some state and regional forecasting (such as the annual AESC Report) uses the average marginal emission rate from an ISO-NE fossil gas plant to calculate the impact of a new heat pump or electric vehicle. This not only overstates the annual impact of new loads but it also fails to identify those peak hourly periods of high emissions where utility load control programs could be very beneficial to reducing emissions and cost.

It should be noted that some programs, such as VT's Tier III requirements for electric utilities, do try to incorporate the carbon intensity of a utility's long-range portfolio to measure savings, but there is no uniform accounting protocol that cover VT's many other existing energy programs and planning efforts.

NREL's Cambium Model has attempted to look at these questions (both the evolution of grid generation and the hourly changes in GHG emissions) to derive regional and state level analyses of the impacts of beneficial electrification. Cambium was built to support NREL's Standard Scenarios—an annually released set of projections of how the U.S. electric sector could evolve across a suite of different potential futures, such as low or high renewable generation costs.

In a recent article, *Planning for the evolution of the electric grid with a long-run marginal emission rate* (iScience, March 2022), NREL researchers Pieter Gagnon and Wesley Cole argue that the current method of just looking at emissions from today's marginal generator is wrong.[10]

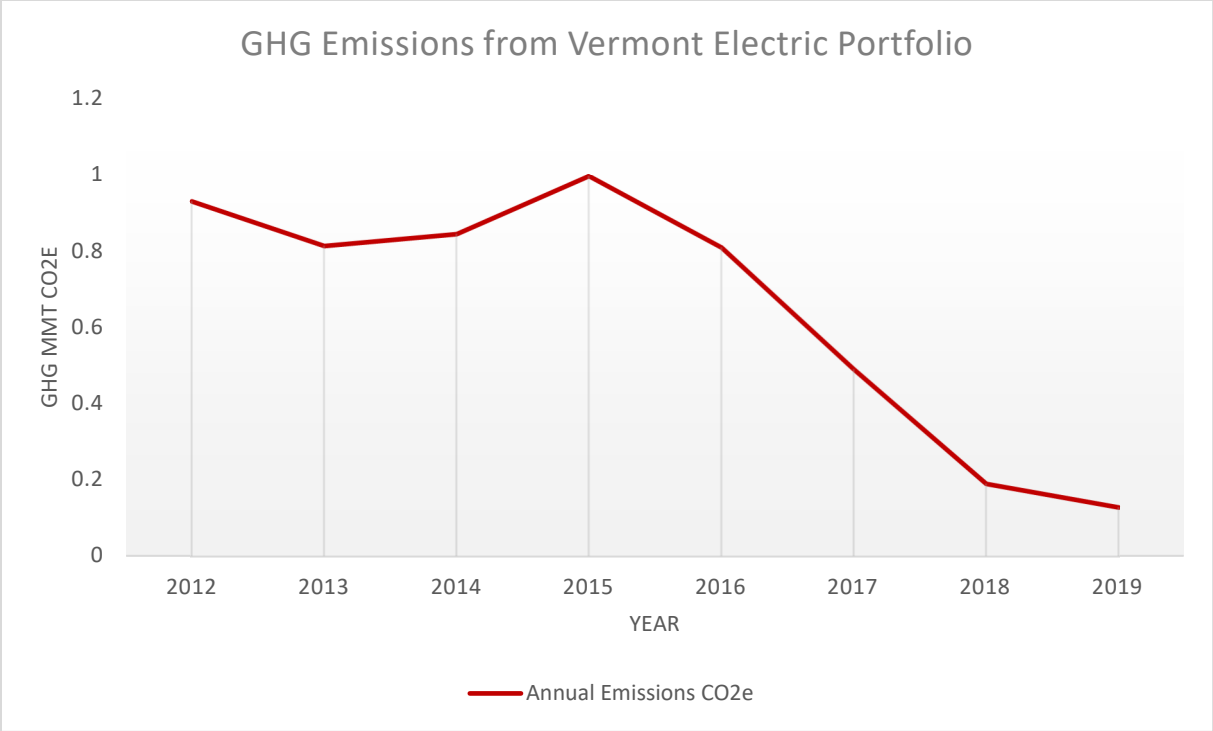
"Emissions factors are widely used to estimate how various interventions would influence emissions from the electric sector. Both of the most commonly used metrics, however, neglect how changes in electricity demand can influence the structural evolution of the grid (the building and retiring of capital assets, such as generators)."

[10] *Planning for the evolution of the electric grid with a long-run marginal emission rate*, iScience, Pieter Gagnon eta al, March 2022

The authors show that a new metric which they call the "long-run marginal emission rate" (LRMER), which relates to the mix of generation as it evolves over the next 20 years, provides the most accurate forecast of GHG impacts due to beneficial electrification. They argue that the "short-run" or current marginal emission rate of the grid does not capture the structural changes in generation and distribution that may be induced by increased demand and future investments. A more detailed discussion of LRMER and the Cambium Model can be found in NREL's 2021 report.[11]

The importance of using LRMER to characterize the impact of beneficial electrification measures is illustrated by Figure 6 which shows the decline in carbon intensity of VT's portfolio since 2012 as reported in VT's annual GHG inventory prepared by the DEC, a division of Agency of Natural Resources.[12]

Figure 6. VT Electric GHG Emissions, 2012 to 2019



Over time, as VT's electric portfolio has relied more on renewable generation and much less on the ISO-NE system mix, that is dominated by fossil gas generation, electric sector emissions have fallen dramatically. **If a heat pump installation in 2015 had been characterized at the then current electric system emission rate for its continuing 15-year life, its lifetime emissions would have been overstated by a factor of five or more.**

NREL's Cambium modeling tool is the first attempt to forecast changes in technology, costs, and emissions that will occur over time. In addition, the model can produce hourly

[11] Ibid, *Cambium Model Documentation,* Gagnon et al, NREL, 2021
[12] *VT Greenhouse Gas Emission Inventory Update,* VT Agency of Natural Resources, 2021

data that can then be matched with the hourly load profile of any new beneficial electrification measure to calculate both the temporal and full operational life emissions of that measure.

This was done for heat pumps in a recent paper by Theresa Pistochini and colleagues at UCLA Davis.[13]

"This paper presents the first detailed emission forecasts for operating either a heat pump or gas furnace for residential heating over a 15-year period, starting in year 2022 through 2036, in six regions across the US. The study accounted for long-run marginal emissions from electricity generation, emissions from natural gas combustion in homes, and fugitive methane and refrigerant emissions from leaks. The population weighted US average results show emission reductions for a heat pump over furnace to be 38–53% for carbon dioxide, 53–67% for 20-Year global warming potential (GWP), and 44–60% for 100-Year GWP, with reductions increasing over time."

For the Northeast, the paper found that a whole house heat pump installation replacing a fossil gas furnace lowered CO2e (measured as GWP100) by approximately 65% in the first year, rising to over 75% in the 15th year. Their analysis relied on the Cambium model which includes pre-combustion GHG emissions for electricity production and used a forecasted ISO-NE long-run marginal emission rate, so the results understate the GHG reductions that would occur in VT with its cleaner generation and purchased portfolio mix.

Since VT relies heavily on #2 fuel oil for heating (approximately 40% of households use fuel oil as their primary heating fuel) and since #2 fuel oil has a higher carbon intensity (CI) than fossil gas, it is also useful to understand the impact of a heat pump system replacing an oil furnace or boiler in VT.

#2 fuel oil contains 40% more carbon than fossil gas (74 vs 53 kg CO2e/MMBTU), and since average combustion efficiency is lower for fuel oil appliances than fossil gas ones, the difference in burner tip carbon emission approaches 50% (93 vs 63 kg CO2e/MMBTU delivered heat).

According to the Cambium model used in the Pistochini paper, VT's long-term marginal emission rate from 2020 to 2035 is estimated to be 35 kg CO2e/MWH. This is probably overstating long-term emissions by at least 50% given that VT's 2020 average emission rate (including fuel cycle emissions) was already down to 24 kg CO2e/MWH, and will decline further over time.

If we assume a marginal long term emission rate of 24 kg CO2e/MWH (no further improvements to the CI of VT's portfolio), then we can conservatively calculate the 15-year GHG reduction due to a whole house heat pump system replacing an oil furnace. Based on standard characterization assumptions for annual heating load and heat pump efficiency (TAG Tier III 2021), **the 15-year GHG savings for a single house converting from an**

[13] *Greenhouse gas emission forecasts for electrification of space heating in residential homes in the US,* Pistochini et al, Energy Policy issue 163, Jan 2022

oil heat system to a heat pump system would be 110,658 kg of CO2e or a 96% reduction in heating system emissions.

The same type of analysis can be done for calculating the emission savings from replacing an ICE vehicle with an AEV vehicle. **The example below shows a 15-year reduction of 70,246 kg of CO2e (98%) for a single EV replacing a current year ICE vehicle**. This assumes a new EV of today's efficiency that remains in VT as a used vehicle after its initial ownership of 7 years (average VT light vehicle turnover).

Figure 7. Comparison of lifetime emissions between an ICE and EV passenger car

	miles/year	MPG	Annual Fuel	CO2e kg/unit	kg CO2e/Year	15-Year Total
ICE	10,900	25.2	433 gal	10.98	4,749	71,239
EV	10,900	-	2,758 kWh	0.024	66	993
GHG Reduction					4,683	70,246

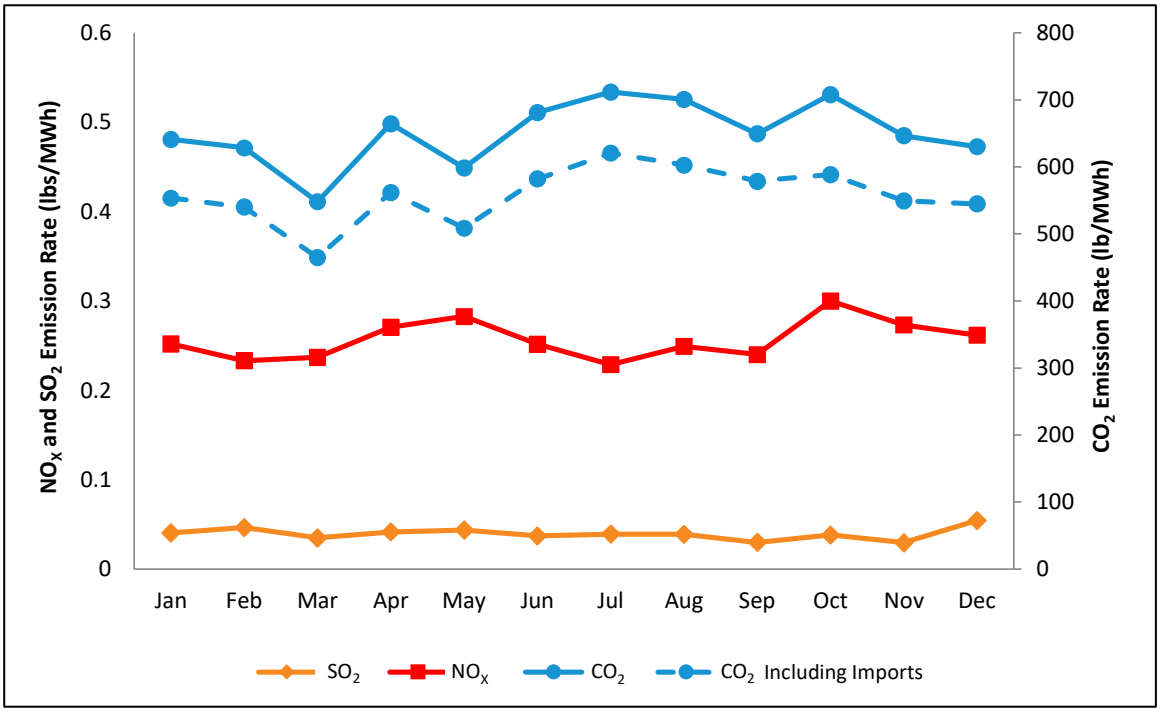
Despite the excellent research behind the Cambium model, its LRMER forecasts are not based on actual utility plans, but on the assumed impact of current regional and state policies and a least-cost generation dispatch model. This lack of more detailed long-range portfolio plans from individual utilities, increases the potential for error in the Cambium estimates of state by state LRMER. If VT were to create a LRMER forecast based on the long-range portfolio planning of each electric utility, this would bring greater accuracy and also greater uniformity to the state's GHG planning and forecasting efforts.

Time Dependency of New Electric Loads & GHG Emissions

It is common practice to evaluate energy consumption and emissions on an annual basis, but a more accurate and useful approach is to evaluate electrical demand and generation mix on an hourly basis. This is due to two reasons. First, because hourly electric load profiles are not flat but exhibit times of peak demand, peaking generators (chiefly fossil gas) are brought on line to supplement base load generators. This causes the emission profile of the electric supply to change during these peak periods. Secondly, because of the increasing amount of variable renewable generation sources, such as solar and wind, balancing resources (again chiefly fossil gas generation) are needed to fill any supply deficits.

Since 1993, ISO-NE has published an annual air emissions report that calculates CO2, NOx, and SOx emissions from its system. **The latest 2020 report (April 2022) is the first to include consideration of the impacts of imports from New York and Canada.[14] Since imports make up 20% of the supply mix, this is an important improvement to ISO-NE's methodology.**

Figure 8. 2020 ISO New England monthly average emission rates (lbs/MWh).

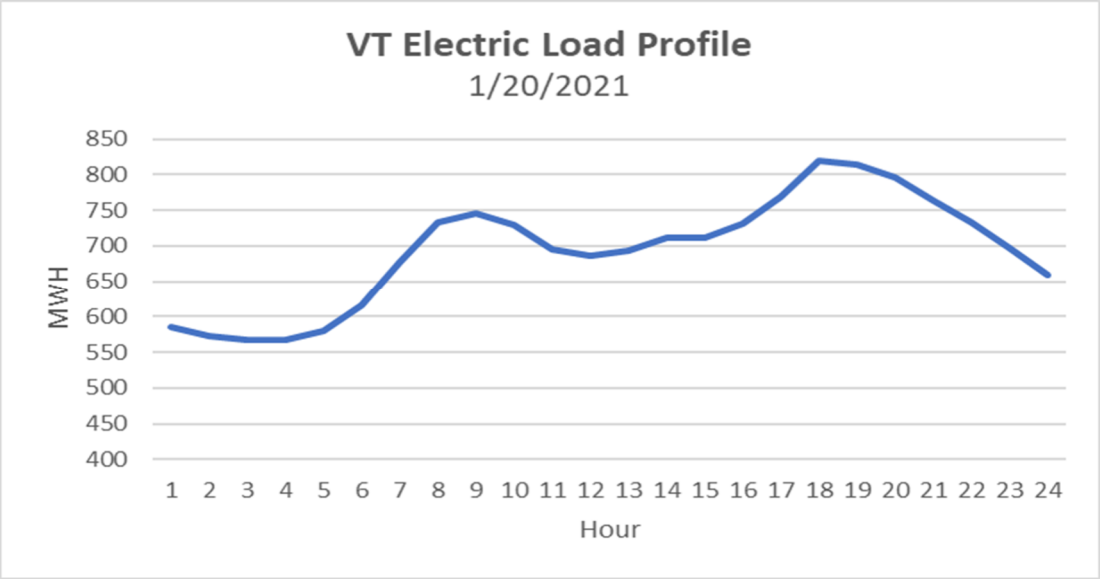


The ISO-NE report clearly shows how emissions vary by month depending on system loads and constraints.

[14] Ibid, *ISO-NE 2020 Generator Air Emission Report*, April 2022

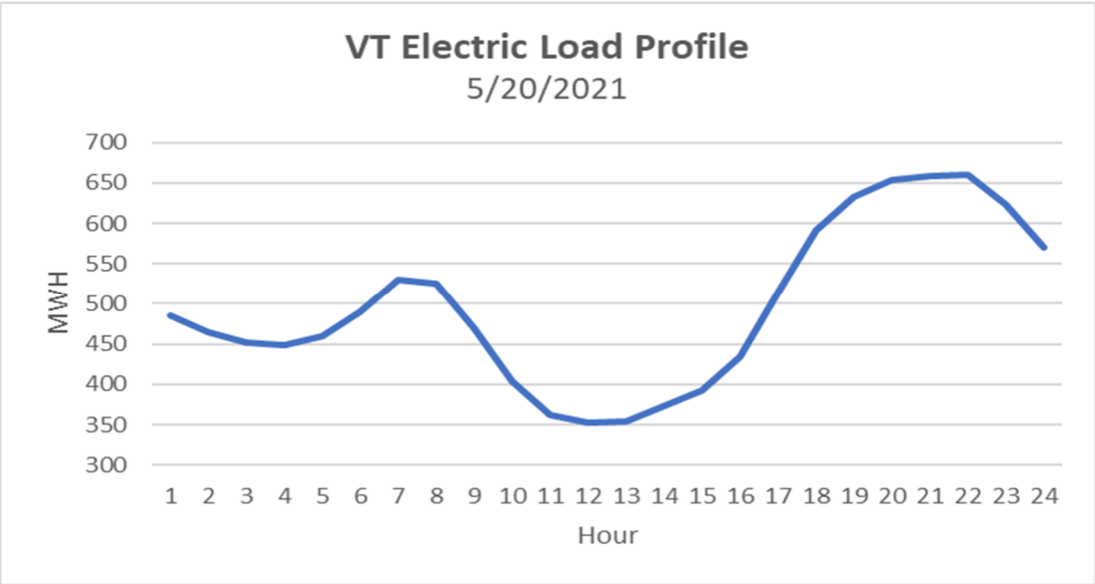
If we look at the hourly profile of VT's electric supply by month, we can get a detailed picture of how peak demand hours and weather dependent generation affect the system. A typical January daily profile is shown below in Figure 9. Both a morning and evening peak are clearly evident. Depending on the size of these peaks, the CI of the electric supply will increase during those hours.

Figure 9. VT Load Profile – January 20, 2021



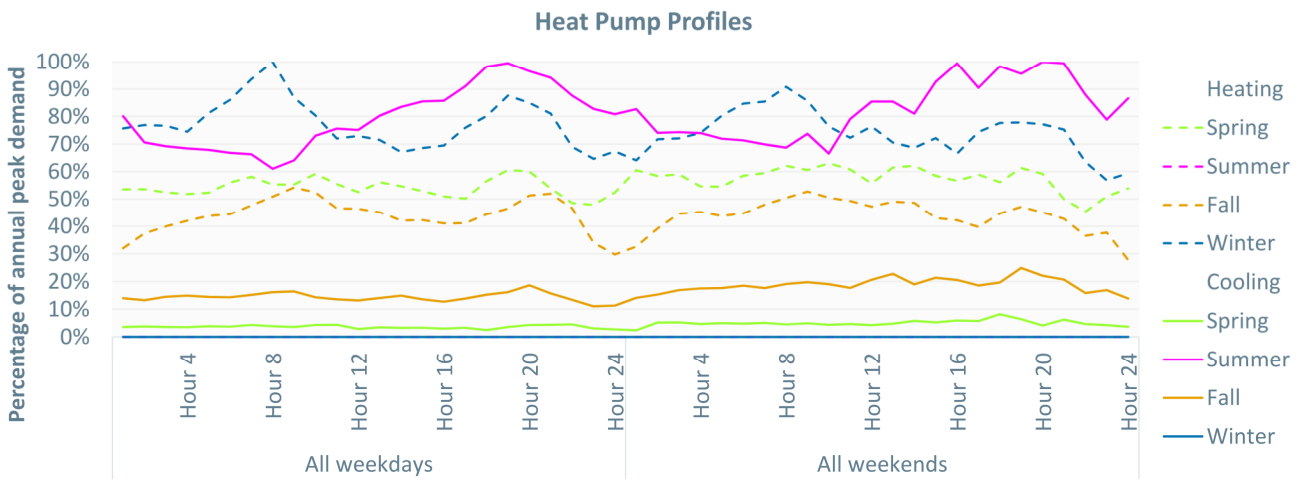
Looking at an hourly profile later in the year (May), the morning and evening peaks are still evident, but lower due to warmer weather. But during mid-day, the impact of solar generation, peaking at noon, is also evident. During these hours, the CI of VT's electricity falls dramatically and is most likely approaching zero.

Figure 10. VT Load Profile – May 20, 2021



Creating an hourly profile of VT's generation sources and assigning appropriate CI values to those sources should be a priority for the PSD working with utilities and VELCO. That profile can then be overlaid with the demand profile for heat pumps, EV charging, and other measures to accurately determine the climate impact of those measures. Figure 11 below shows the hourly load profile associated with heat pumps in VT used for both heating and cooling.

Figure 11. LEAP model assumptions prepared for the VT Climate Council, Stockholm Environment Institute, Nov 2021



Not only will this information provide a more accurate estimate of GHG emissions but it will provide additional data to be used by utilities in determining the most beneficial design of load control programs including both direct control and customer initiated "flexible load" management.

While VT has yet to research and create hourly GHG profiles, ISO-NE has created 15-minute air emission calculations for its mix of generation sources. This data is useful (and informs the NREL Cambium model) but does not reflect VT's electricity purchases and overall portfolio, so is of limited use to guiding our emission research and planning.

Once an hourly GHG profile has been created, it can be used to model changing year-on-year emission rates due to expected changes to VT's load growth, contracts, and transmission system. This would provide a VT specific LRMER that could be used for modeling the impact of beneficial electrification. In conjunction with Vermont's Comprehensive Energy Plan, the LRMER could be updated every six years to adjust for changes in technology or utility planning.

Links to Cited Source Information

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2. *Energy Action Network*, research by L.W. Seddon
   - Based on 2020 MWH generation & utility data from the VT Public Service Department
   - HQ is considered 100% renewable under VT RES. Actual RE generation percentage is about 96%. GHG emissions assumed to be zero under current ANR GHG inventory methodology. Most recent research (see Source #6) indicates operational GHG emissions of 24 kg/MWH
   - ISO-NE mix was 17% renewable in 2019, excluding refuse burning plants. Solar, wind, and hydro assumed to be zero GHG. ISO-NE "emitting plants" had an average CO2e emission rate of 388 kg/MWH in 2019 (includes NOx)
3. *ISO-NE 2020 Generator Air Emission Report*, April 2022. https://www.iso-ne.com/static-assets/documents/2022/05/2020_air_emissions_report.pdf
4. 2020 data from ISO-NE and VT Department of Public Service
5. *Cambium Model Documentation,* Gagnon et al, NREL, 2021. https://www.nrel.gov/docs/fy22osti/81611.pdf
   See also the online NREL Cambium Viewer at https://scenarioviewer.nrel.gov/
6. *Improving the accuracy of electricity carbon footprint: Estimation of hydroelectric reservoir greenhouse gas emissions*, Levasseur et al, Renewable and Sustainable Energy Reviews, 2021 https://www.sciencedirect.com/science/article/pii/S1364032120307206
7. *Life-cycle Greenhouse Gas Emissions from Electric Generation, NREL/FS-6A50-80580* September 2021 https://www.nrel.gov/docs/fy21osti/80580.pdf
8. Based on information provided by the VT Public Service Department for the 2020 RES compliance report. GHG emission rates include "pre-combustion" estimates. https://publicservice.vermont.gov/content/annual-res-reports
9. *Planning for the evolution of the electric grid with a long-run marginal emission rate*, iScience, Pieter Gagnon eta al, March 2022 https://www.sciencedirect.com/science/article/pii/S2589004222001857
10. *VT Greenhouse Gas Emission Inventory Update,* VT Agency of Natural Resources, 2021 https://dec.vermont.gov/air-quality/climate-change
11. *Greenhouse gas emission forecasts for electrification of space heating in residential homes in the US,* Pistochini et al, Energy Policy issue 163, Jan 2022 https://www.sciencedirect.com/science/article/pii/S0301421522000386