ONTARIO ENERGY BOARD

EB-2020-0293

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S. O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF an application for leave to construct natural gas pipeline and associated facilities in the City of Ottawa.

Environmental Defence Compendium - Volume 2

March 2, 2022

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Note: This compendium was previously filed in EB-2020-0091 (Exhibit K2.1). See https://www.rds.oeb.ca/CMWebDrawer/Record/705615/File/document. The cover page has been updated.

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ONTARIO ENERGY BOARD

EB-2020-0091

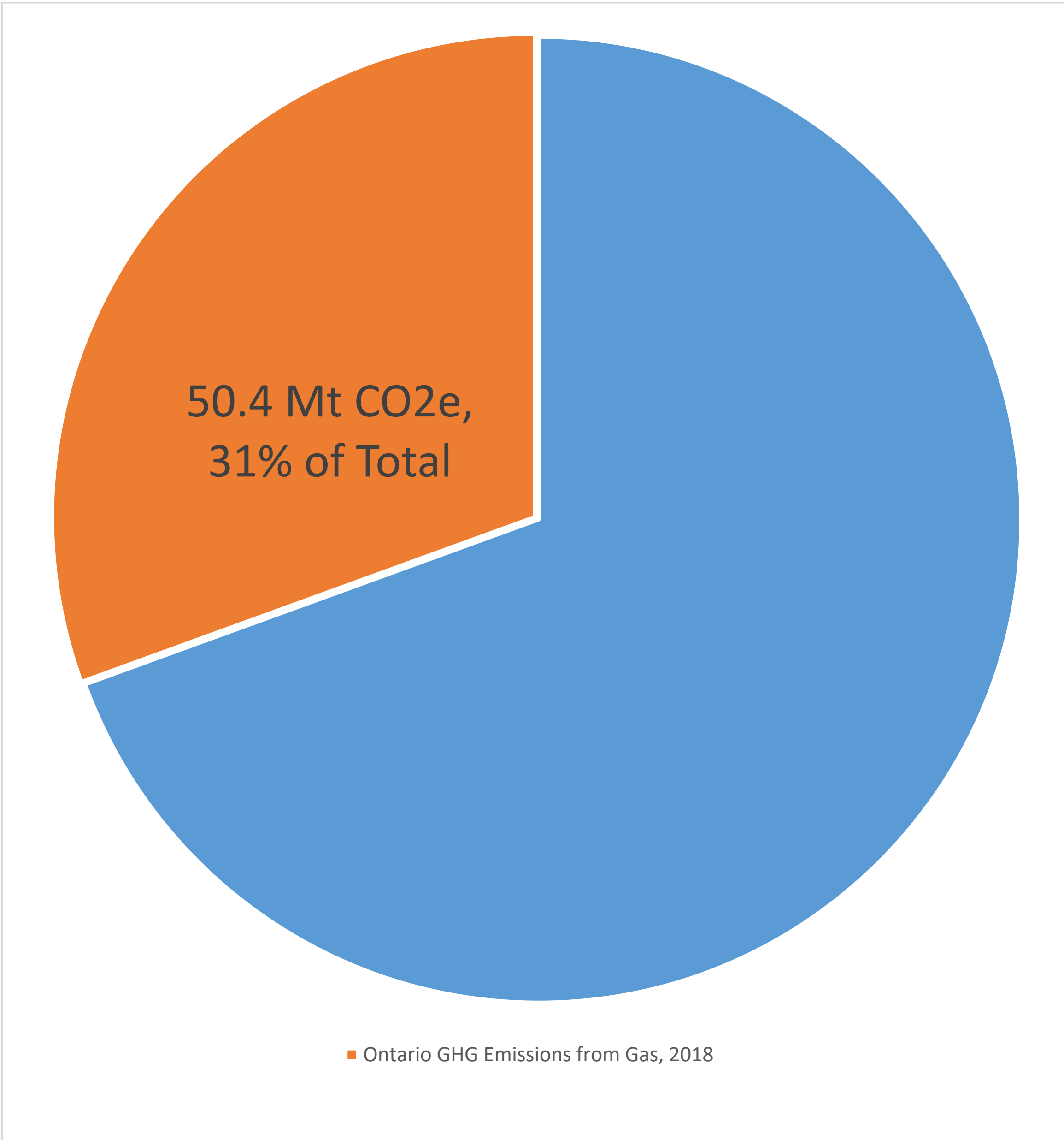
IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S. O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF a generic hearing on Integrated Resource Planning.

Figures Created with Enbridge Evidence and OEB Reports

Contents

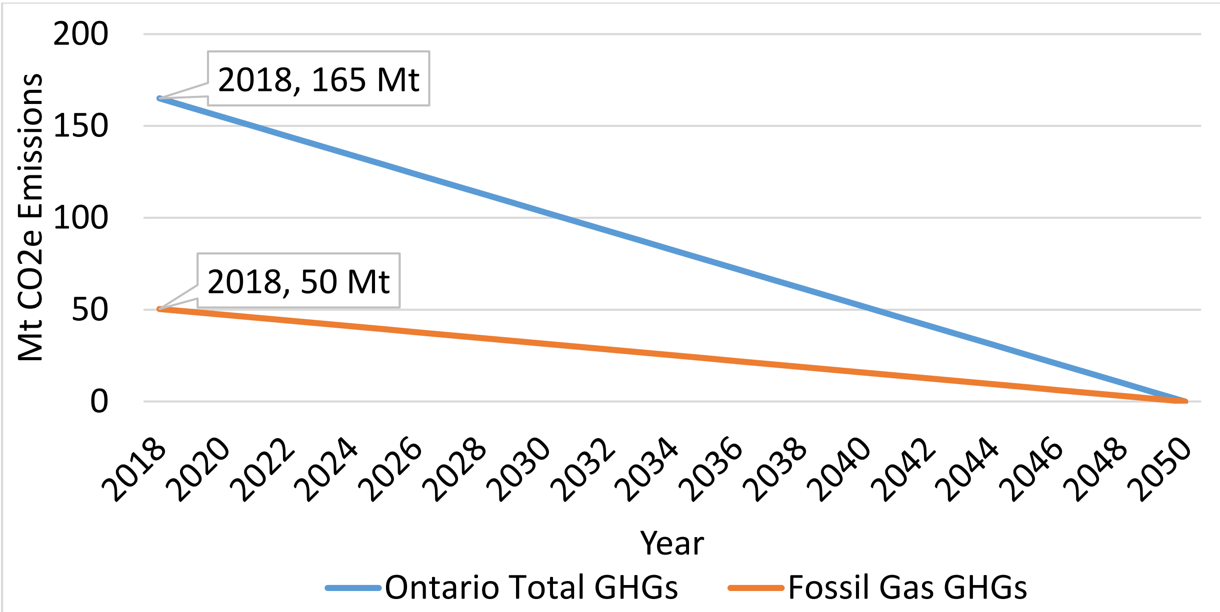
Ontario GHG Emissions from Fossil Gas as % of Total Ontario Emissions (2018)



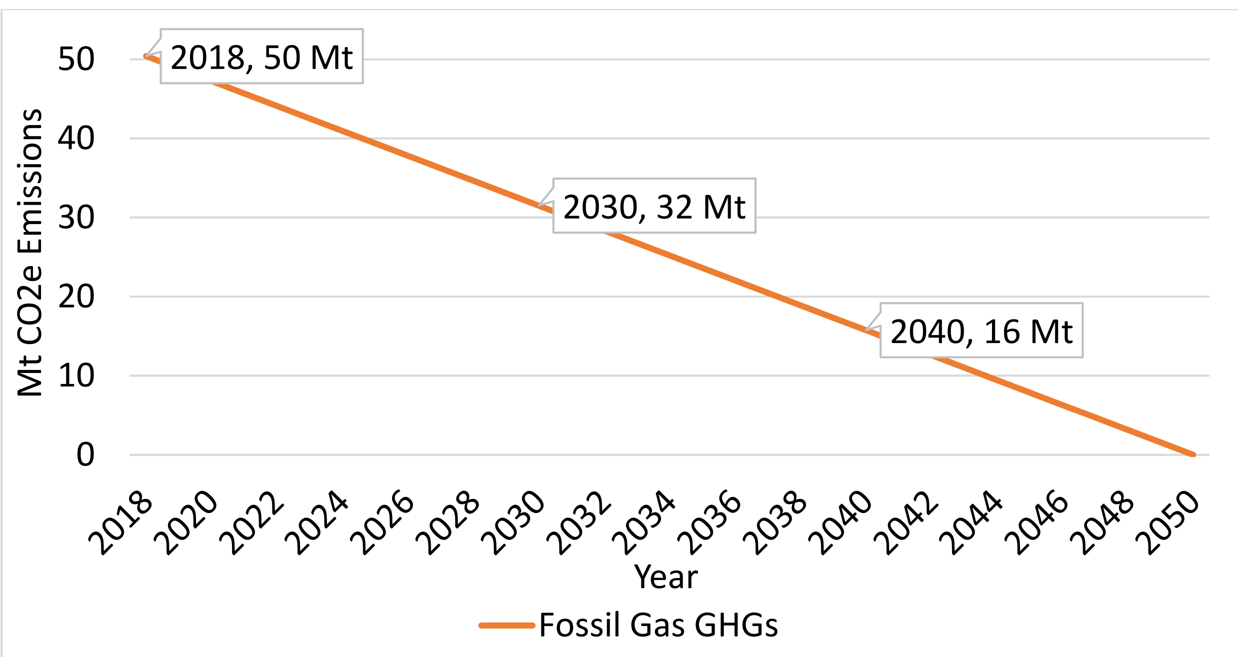
Ontario GHG Emissions from Natural Gas as % of Total Ontario Emissions (2018)			
	Ontario GHG Emissions Total	Ontario GHG Emissions from Gas, 2018	Gas Emissions as % of Total
Mt CO2e	165	50.4	31%

Source: EB-2020-0136, Exhibit I.ED.7 (link, PDF p. 112)

Linear GHG Emission Decline to Net Zero
Ontario Total and Fossil Gas

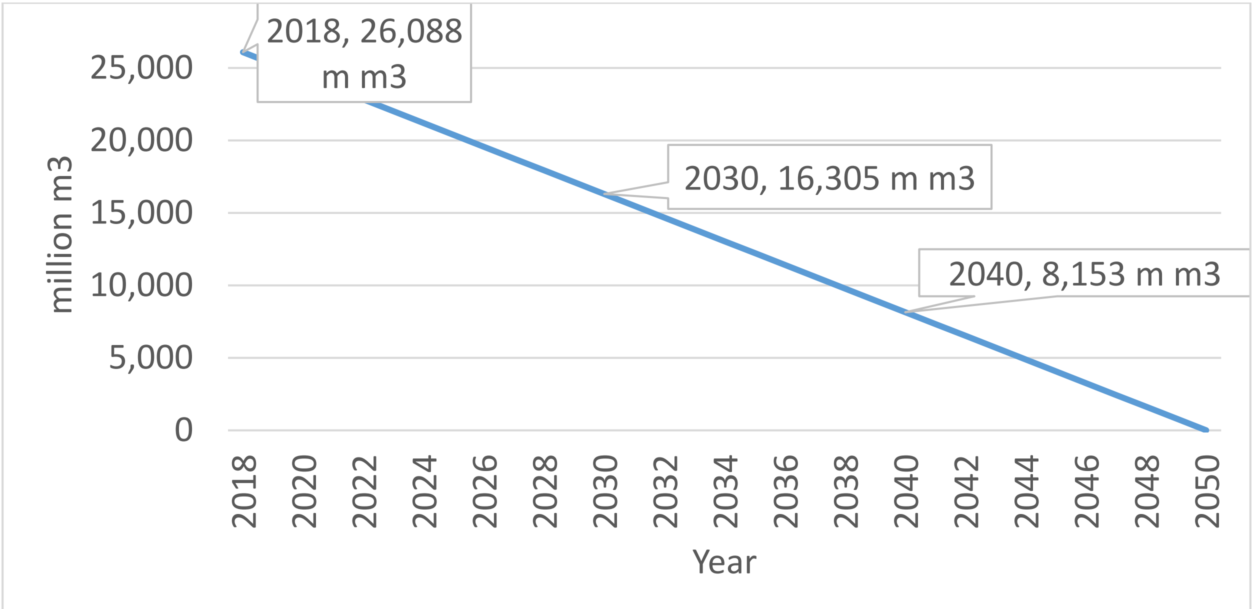


Linear GHG Emission Decline to Net Zero
Fossil Gas Only

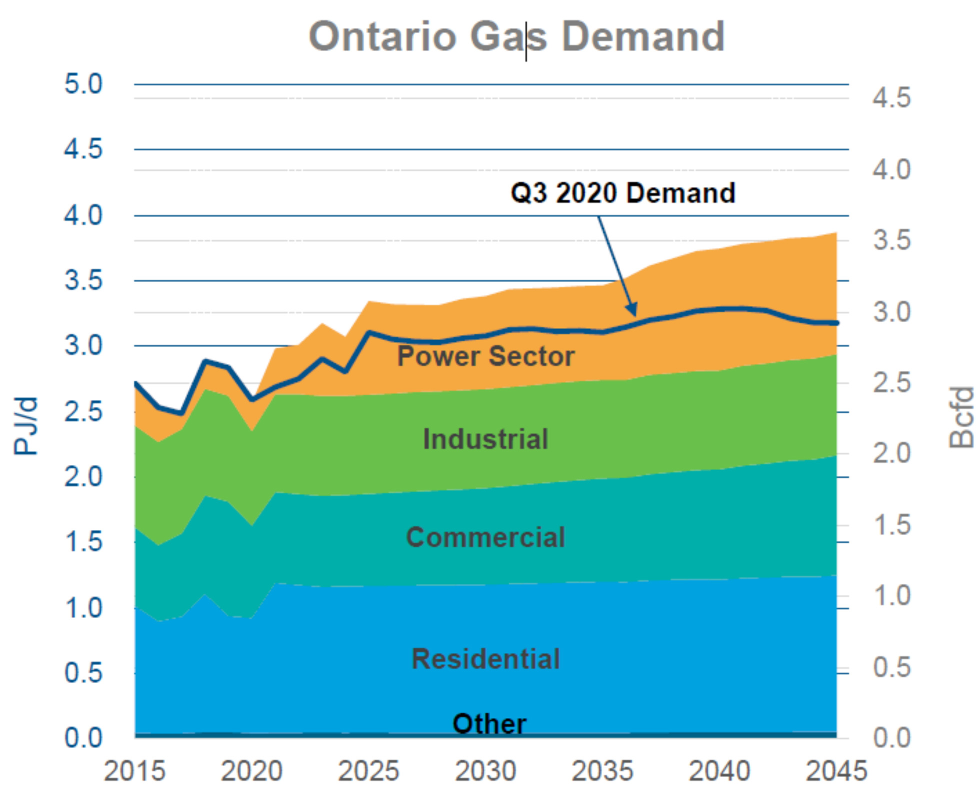


Source: EB-2020-0136, Exhibit I.ED.7 (link, PDF p. 112)

Linear Decline in Fossil Gas to Net Zero

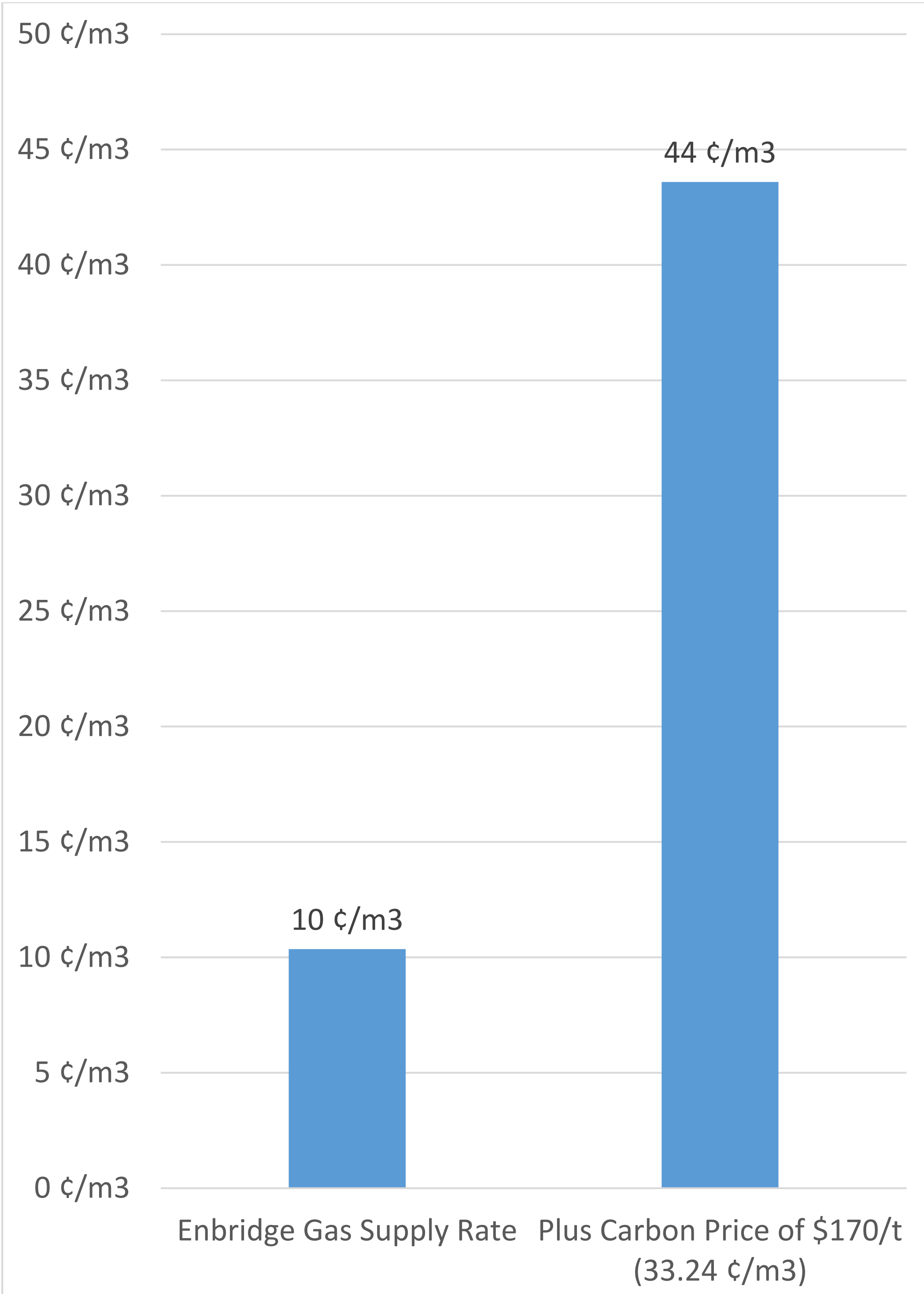


Enbridge 2021 Annual Gas Supply Plan



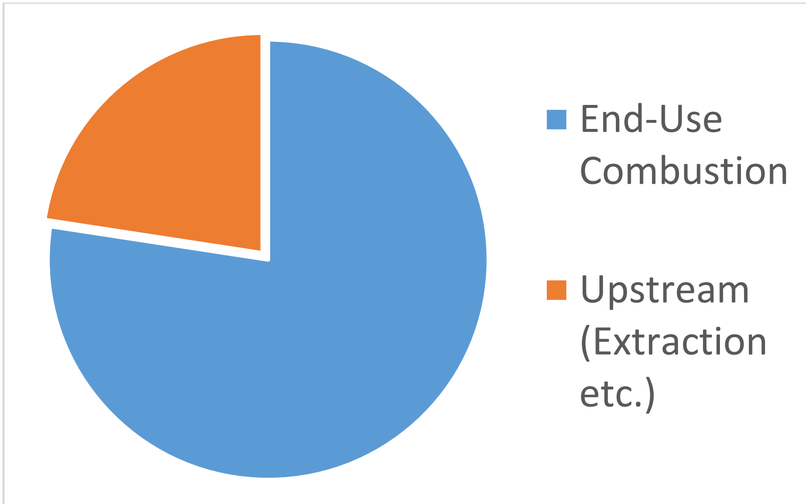
Sources: Ontario Energy Board, *Yearbook of Natural Gas Distributors*, 2018 (total gas volumes = 26,088 million m3) (link, PDF p. 2); EB-2021-0004, 2021 Annual Gas Supply Plan Update, Enbridge Gas Inc., February 1, 2021, p. 13

Impact of $170/tonne Carbon Price on Current Gas Supply Rate



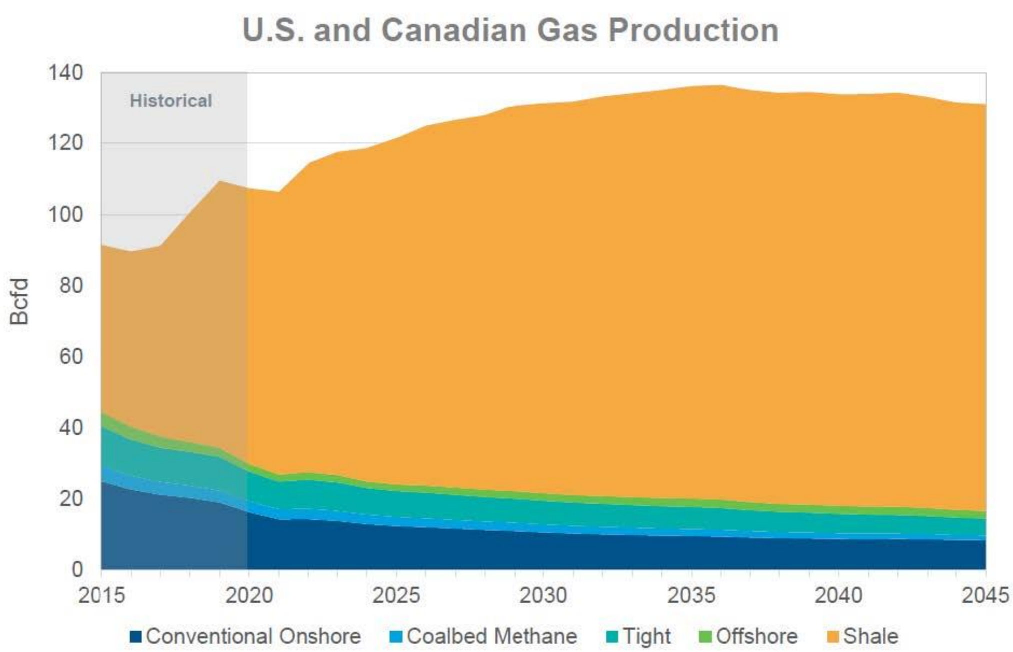
Source: OEB, Natural Gas Rates, (link); Enbridge, Federal Carbon Charge, (link)

Upstream GHG Emissions from Fossil Gas Per Enbridge Evidence



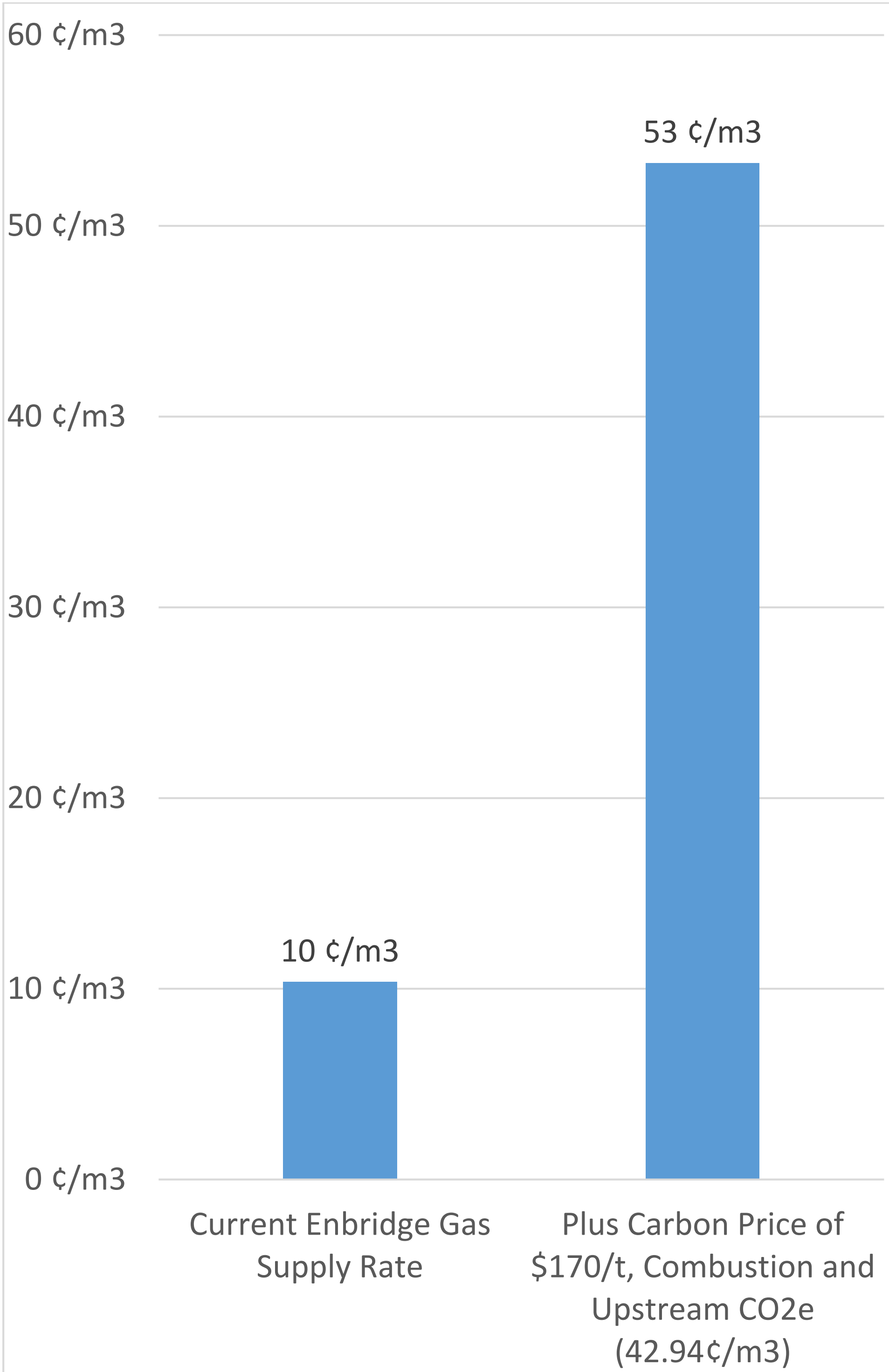
Upstream natural gas emissions (e.g. extraction) represent approximately an additional 29.2% of emissions incremental to those from combustion per Enbridge's evidence (EB-2020-0066, Exhibit JT1.7).

Fossil Gas – Conventional vs. Hydraulic Fracturing



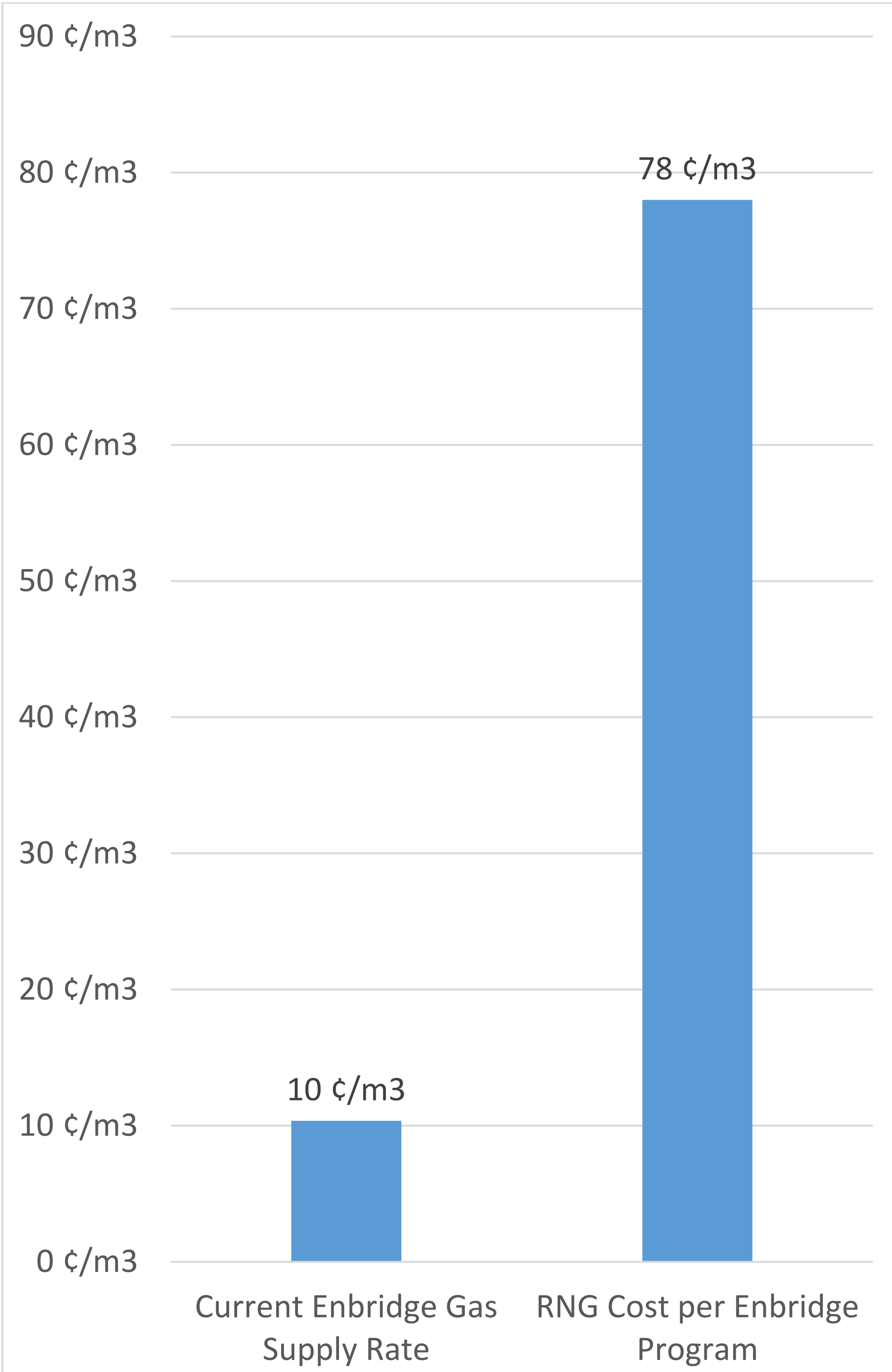
Source: EB-2020-0066, Exhibit JT1.7 (link); EB-2021-0004, 2021 Annual Gas Supply Plan Update, Enbridge Gas Inc., February 1, 2021, p. 11.

Impact of $170/tonne Carbon Price on Current Gas Supply Rate (Combustion and Upstream)



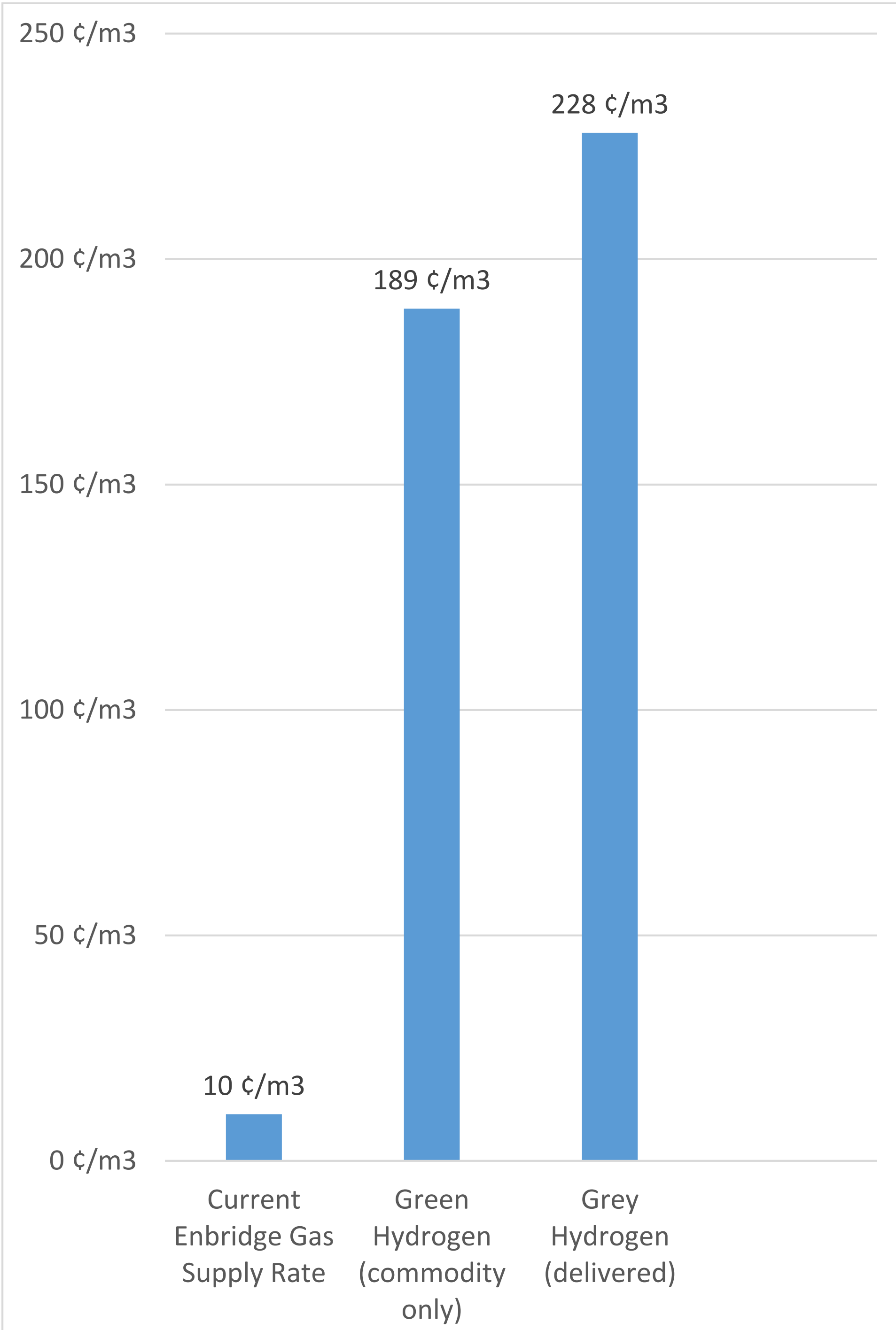
Source: OEB, Natural Gas Rates, (link); Enbridge, Federal Carbon Charge, (link); EB-2020-0066, Exhibit JT1.7 (link).

Current Gas Supply Rate vs. Cost of Renewable Natural Gas in Enbridge's RNG Program



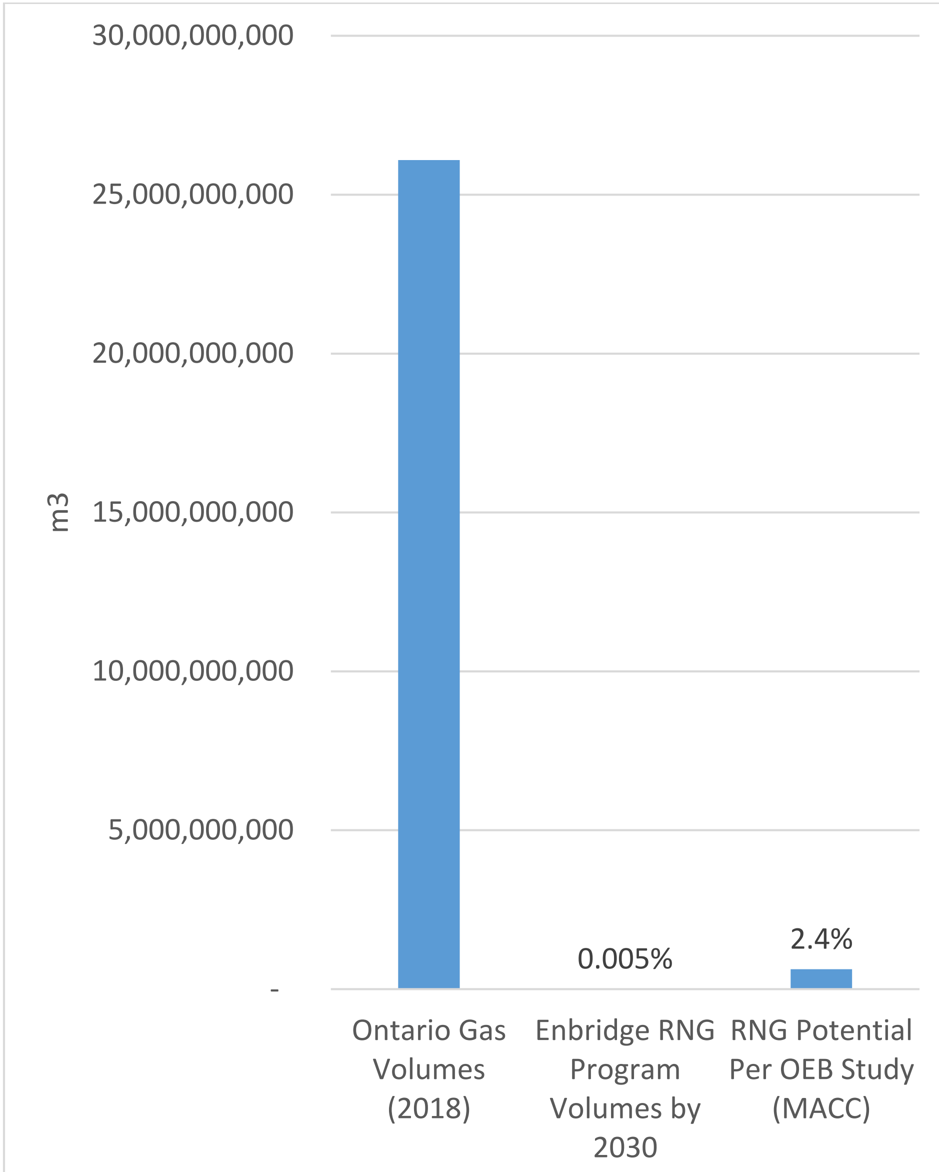
Source: OEB, Natural Gas Rates, (link); EB-2020-0066, Exhibit I.STAFF.8, Page 3 (link, PDF p. 22)

Current Gas Supply Rate vs. Cost of Hydrogen per Enbridge's Evidence



Notes: Green hydrogen: created from electrolysis; Grey hydrogen: created from fossil gas. Hydrogen price given as an equivalent to an m3 of fossil gas (hydrogen has 1/3rd the heating value of fossil gas per EB-2019-0294, Exhibit B, Tab 1, Schedule 1, Page 3, link).
Source: EB-2019-0294, Exhibit I.ED.6(g)&(i) (link, PDF p. 172-173).

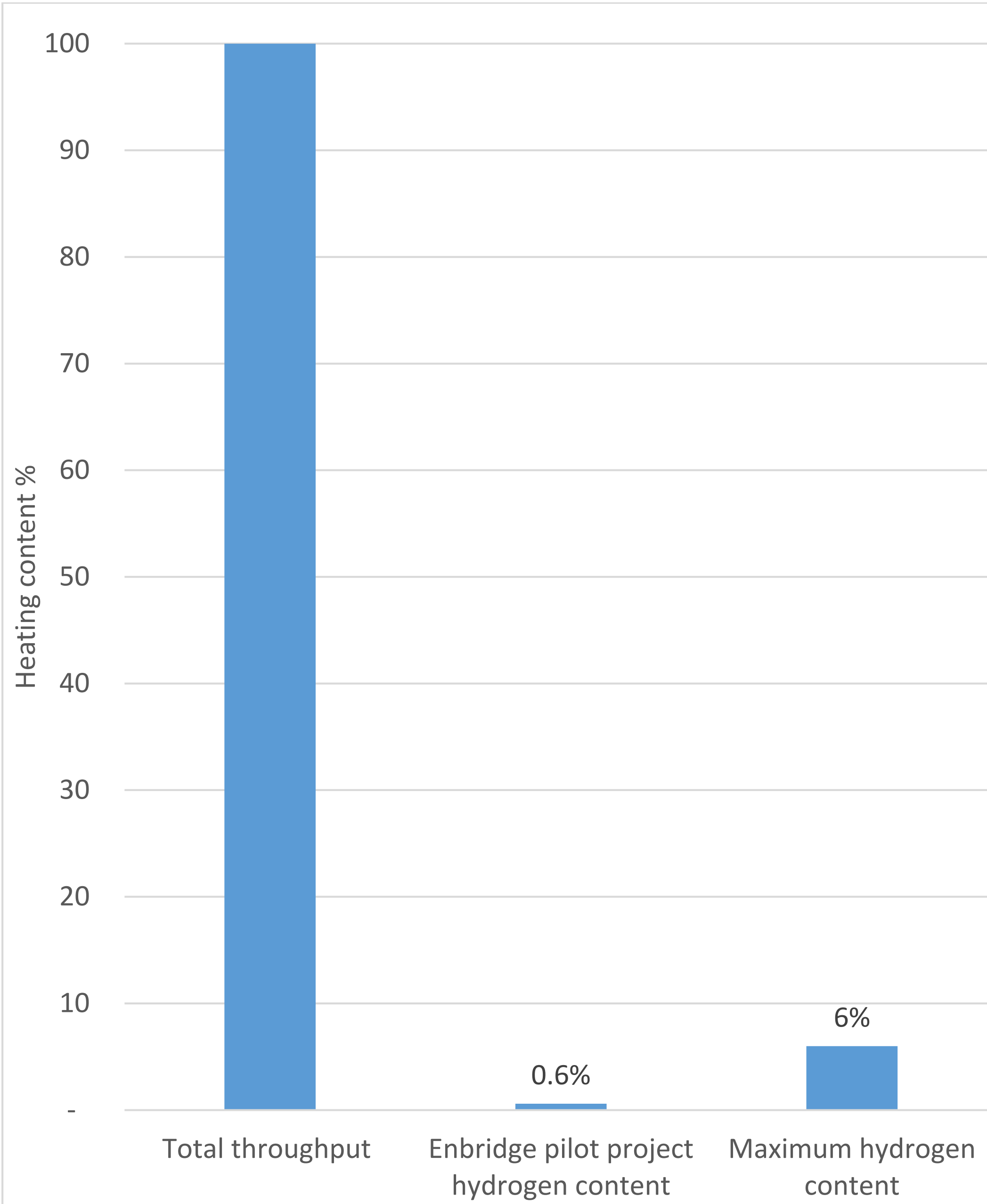
RNG - Volumes from Enbridge RNG Program and Ontario's RNG Potential



	Ontario Gas Volumes (2018)	Enbridge RNG Program Volumes by 2030	RNG Potential Per OEB Study (MACC)
m3	26,088,000,000	1,398,974	627,000,000
Percent of Ontario Volumes		0.005%	2.4%

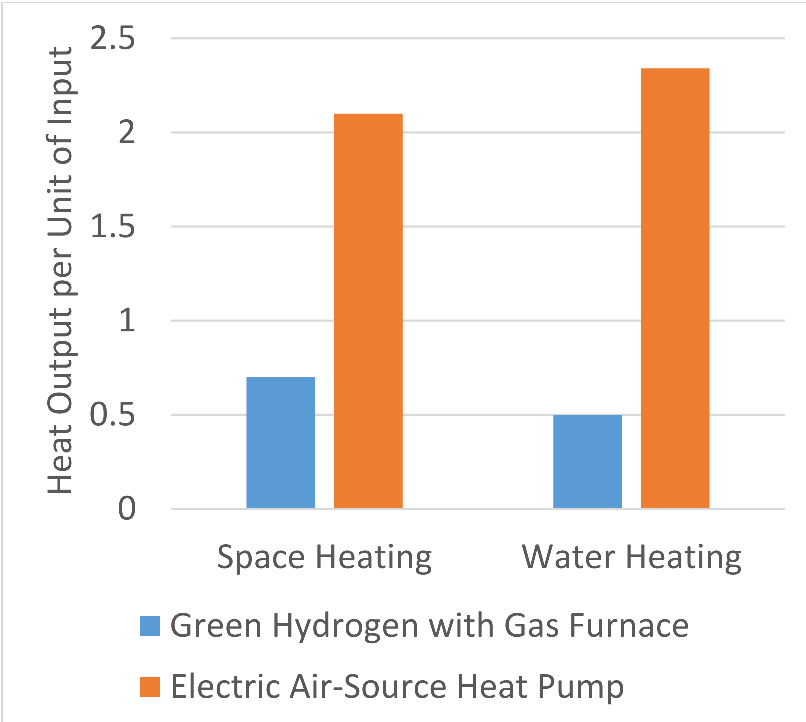
Sources: OEB, Natural Gas Rates, (link); EB-2020-0066, Exhibit I.STAFF.8, Page 2 (link, PDF p. 21); EB-2016-0359, ICF, *Marginal Abatement Cost Curve*, July 20, 2017, prepared for the OEB, p. 47 (link, pdf p. 47).

Hydrogen – Potential for Fossil Gas Replacement with Existing Equipment and Pipes



Notes and sources: Enbridge's pilot project will blend 2% hydrogen by volume. Because hydrogen is less energy dense, this amounts to 0.6% by energy content. See Exhibit I.ED.12, p 14-15 (h)&(i) (link, PDF p. 15-16). No studies are considering blending beyond 20% by volume (per Exhibit I.ED.7, link, PDF p. 177), which equates to 6% by energy content. Hydrogen has 1/3rd the heating value of fossil gas per EB-2019-0294, Exhibit B, Tab 1, Schedule 1, Page 3, link).

Energy Efficiency Comparison Between Green Hydrogen with Gas Furnace and Electric Heat Pumps for Space and Water Heating



	Space Heating		**Water Heating**	
	Gas Furnace	**Heat Pump**	**Gas Heater**	**Heat Pump**
Energy input	1 kWh	1 kWh	1 kWh	1 kWh
Hydrogen conversion loss[1]	25%	n/a	25%	n/a
Energy input minus loss[2]	0.75 kWh	1 kWh	0.75 kWh	1 kWh
Annual heating efficiency[3]	95%	210%	67%	234%
Heat output[4]	0.7 kWh	2.1 kWh	0.5 kWh	2.34 kWh
Output difference[5]	295%		465%	

[1] Enbridge acknowledges that electrolysis results in approximately 25% conversion loss. The amount of electricity to run the electrolysis equipment is about 4.7 kWh/m³ per Exhibit I.ED.6(g) [link, PDF p. 173]. One m³ of hydrogen equals 3.5278 kWh of hydrogen per the conversion factors in I.ED.3(c) [link, PDF p. 165]. An input of 4.7 kWh and output of 3.5278 kWh amounts to approximately 25% energy loss. Per EB-2020-0091, Exhibit I.ED.7, the annual coefficient of performance of Cold Climate Air Source Heat Pumps in climates similar to Ontario is reported to be in the range of 2.5 to 2.75.
[2] Calculation: 1 kWh minus 25% loss for hydrogen conversion.
[3] EB-2016-0359, ICF, *Marginal Abatement Cost Curve*, July 20, 2017, prepared for the OEB, p. A-3 [link]. Note that this report uses annual heating efficiency percentages for standard heat pumps, not the more efficient cold climate heat pumps.
[4] Calculation: "Energy input minus loss" multiplied by "Annual heating efficiency."
[5] Calculation: heat output of heat pumps divided by heat output of the gas equipment.

Comparison of Ontario Fossil Gas Decarbonization Options

	Cost-effectiveness ($/t$CO_2$e, combustion only)	**Decarbonization potential** (% of Ontario gas demand)
Hydrogen	>$900 (commodity cost) + ~$4,000 (capital cost) [6]	6%[7]
Cost-effective energy efficiency	$0 to -$140 (i.e. savings)[8]	25%[9]
Heat pumps	$130 to $200[10] (commodity & capital cost)	Near 100%[11]
RNG	$338[12]	2.5%[13]

[6] Exhibit I.ED.11(a)&(b), p. 2-3 [link, PDF p. 197-198]; Per Exhibit JT1.7 in EB-2020-0066 [link, PDF p. 398], if upstream emissions are accounted for, the cost is over $700/tCO2e for commodity costs and over $3,000 for capital costs.

[7] Enbridge is proposing to blend 2% hydrogen by volume. Because hydrogen is less energy dense, this amounts to 0.6% by energy content. See Exhibit I.ED.12, p 14-15 (h)&(i), link, PDF p. 15-16. No studies are testing blending beyond 20% by volume (per Exhibit I.ED.7, link, PDF p. 177), which equates to 6% by energy content.

[8] EB-2016-0359, ICF, *Marginal Abatement Cost Curve*, July 20, 2017, prepared for the OEB, p. 14 [link]; Per Exhibit JT1.7 in EB-2020-0066 [link, PDF p. 398], if upstream emissions are accounted for, the cost is $0 to -$108/tCO2e.

[9] Navigant, *2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study*, prepared for the IESO and OEB, December 18, 2019, p. ix [link].

[10] EB-2016-0359, ICF, *Marginal Abatement Cost Curve*, July 20, 2017, prepared for the OEB, p. A-4 to A-5 14 [link] (heat pumps are $130/t$CO_2$e for new homes and $200/t$CO_2$e for existing homes according to this study, but prices are declining significantly as cold climate heat pumps become more commonplace); Per Exhibit JT1.7 in EB-2020-0066 [link], if upstream emissions are accounted for, the cost is $101 to $155/tCO2e.

[11] EB-2016-0359, ICF, *Marginal Abatement Cost Curve*, July 20, 2017, prepared for the OEB, p. 25 [link].

[12] EB-2020-0066, Exhibit I.SEC.15 [link]; Per Exhibit JT1.7 in EB-2020-0066 [link, PDF p. 398], if upstream emissions are accounted for, the cost is $262/tCO2e.

[13] EB-2016-0359, ICF, *Marginal Abatement Cost Curve*, July 20, 2017, prepared for the OEB, p. 47 [link]; This report estimates a potential of 627 million m^3/yr, which is 2.41% of Ontario's consumption of 26 billion m^3/yr. This potential was considered achievable by 2028 based on a study conducted in 2013. In Exhibit JT1.5 [link], Enbridge estimates the potential as 402 million m^3/yr by 2025, which is 1.55% of Ontario's gas consumption of 26 billion m^3/yr.

Filed: 2020-10-21
EB-2020-0136
Exhibit I.ED.7
Page 1 of 1

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit B, Schedule 1, Pages 8 & 25-30

Question:

(a) Please confirm the percentage of Ontario's annual greenhouse gas emissions that are attributable to natural gas combustion.

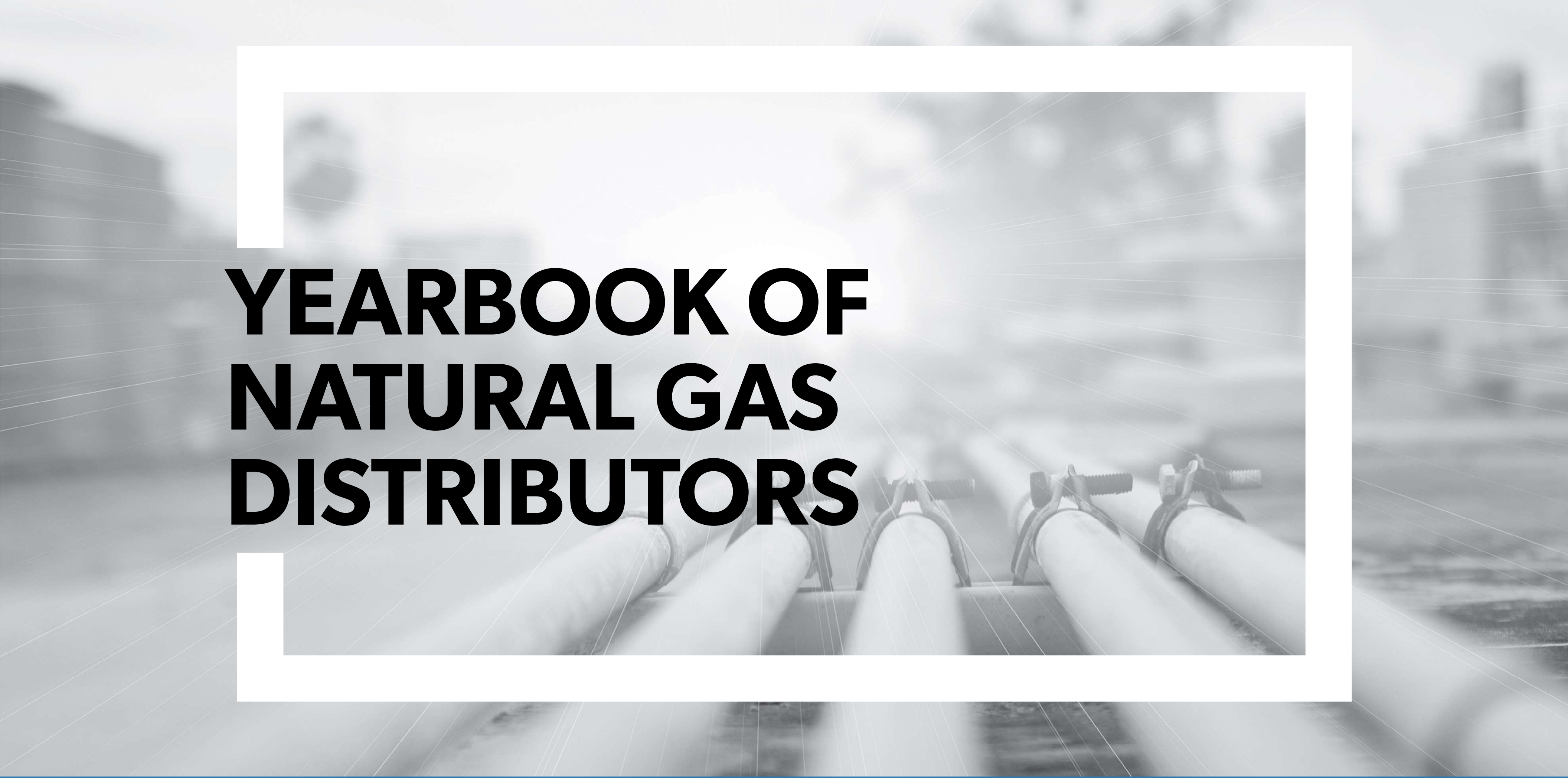
(b) Please estimate the probability (%) that electric heat pumps will be a significantly less expensive method to heat most buildings compared to natural gas (e.g. due to carbon pricing, improved equipment, etc.) in: (i) 2030, (ii) 2040, and (iii) 2050. Please provide a specific percentage with any caveats as necessary.

Response:

a) The percentage of Ontario's annual greenhouse gas emissions that are attributable to natural gas combustion is 31% as of 2018, the most recent year for which data was available.[1]

b) Please see Exhibit I.ED.2 e).

[1] Based on natural gas consumption data from Statistics Canada (Canadian Monthly Natural Gas Distribution, Table 25-10-0059-01) and GHG emissions data from Environment Canada (2020 National Inventory Report, Table A11-12). Emissions from natural gas combustion in Ontario were 50,376 ktCO_2e in 2018. Total GHG emissions in Ontario were 165,000 ktCO_2e in 2018.



YEARBOOK OF NATURAL GAS DISTRIBUTORS

2018

Published on August 19, 2019

Ontario

Ontario Energy Board

Key Metrics Overview of Ontario Natural Gas Distributors' Sector of Electricity Distributors

Industry Metrics Snapshot

Financial Item / Metric	2014	2015	2016	2017	2018
Operating Revenues ($) [1]	5,181,639,409	5,355,148,952	4,629,905,581	5,446,016,294	**5,388,183,841**
Net Income ($)	442,065,542	421,783,556	433,988,410	481,665,263	**565,379,399**
Return on Shareholders' Equity (%) [2]	10.54%	9.31%	8.69%	8.93%	**11.45%**
Operating Expenses ($) [3]	3,944,081,790	4,133,742,026	3,336,245,690	4,050,734,331	**3,874,781,299**
Depreciation Expense ($)	495,727,421	512,240,846	558,697,466	594,168,499	**608,808,669**
Net Property, Plant and Equipment ($)	11,445,517,496	12,836,248,365	13,993,950,193	15,312,793,338	**15,037,654,293**
Number of Customers [4]	3,489,238	3,540,089	3,598,700	3,653,986	**3,701,403**
Gas Volumes (in million cubic meters) [5]	27,271	25,702	24,564	24,533	**26,088**

[1] Operating revenues include revenues derived from utility operations.

[2] ROE is calculated as the sum of gas utilities' net income divided by total shareholders' equity.

[3] Operating expenses includes gas cost, operating and maintenance expenses.

[4] Total customers include system gas customers and direct purchase customers of gas marketers licensed by the OEB.

[5] Annual gas volumes include quantities of gas sold to system gas customers and quantities of gas delivered to direct purchase customers.

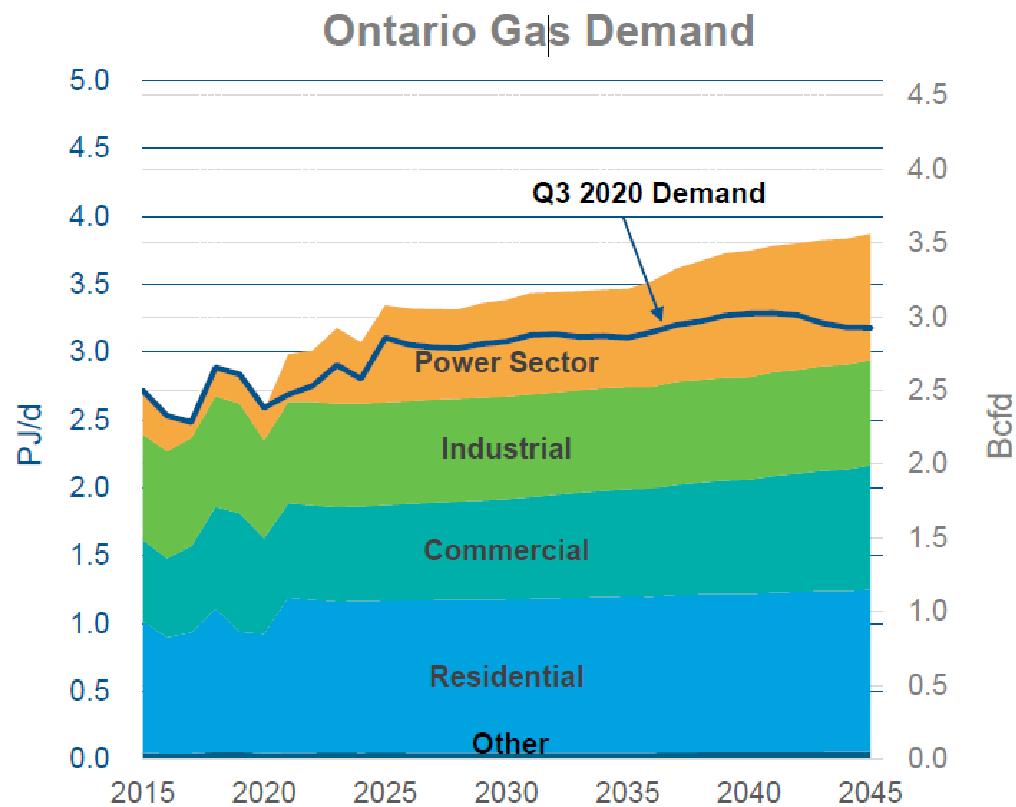
2021 Annual Gas Supply Plan Update

EB-2021-0004

Enbridge Gas Inc.
February 1, 2021

ENBRIDGE

Figure 3 - Ontario Natural Gas Demand



Source: ICF Q4 2020 Natural Gas – Strategic. Used with permission.

Natural Gas Price Signals

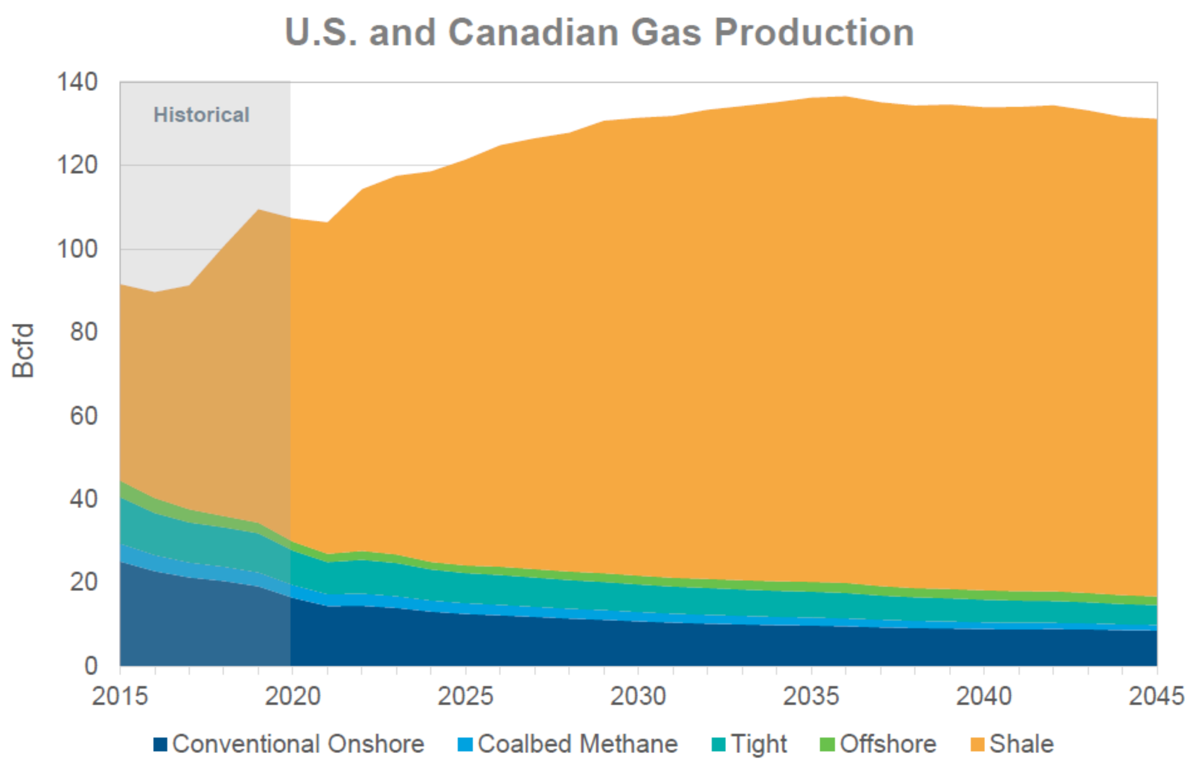
Throughout the winter of 2019/20, natural gas prices were historically low. This was driven by warmer than normal winter temperatures which kept demand for natural gas low, while continued supply from Marcellus, Utica, Permian, and Haynesville production basins kept supply buoyant. North American storage levels were consistently above the five-year average, providing downside pressure on prices. According to the U.S. Energy Information Administration ("EIA")[22] October 2020 storage levels across North America were more than 5% higher than the five-year average. However, EIA forecasts that declines in U.S. natural gas production this winter compared with last winter will more than offset the declines in natural gas consumption, which will contribute to inventory withdrawals outpacing the five-year average during the remainder of the winter season that ends in March 2021. Forecast natural gas inventories are expected to end March 2021 at 1.6 Tcf, 12% lower than the 2016-20 average. This is expected to place upward pressure on near-term natural gas prices. Despite these near-term forecasted price increases, natural gas prices remain low relative to historic averages.

Natural gas prices set at Henry Hub are generally seen to be the primary price for the North American natural gas market with locational basis differentials based off the New York Mercantile

[22] EIA January 2020 Short-term Energy Outlook: https://www.eia.gov/outlooks/steo/report/natgas.php

of all U.S. and Canadian gas production. Conventional production is expected to decline by 2.6% annually.[18]

Figure 1 - U.S. and Canadian Natural Gas Production by Type



Source: ICF Q4 2020 Natural Gas – Strategic. Used with permission.

In its 2020 Energy Future ("EF2020"), the Canada Energy Regulator ("CER") projects Western Canadian Sedimentary Basin ("WCSB") natural gas production will remain consistent until 2025 and then grow to 18.4 Bcf/d by 2040. In the longer term, rising prices and the onset of LNG export demand support higher capital expenditures from producers and therefore natural gas production growth.[19]

Natural Gas Demand

The impact of restrictions related to COVID-19 on Canadian energy consumption has been significant with the greatest impact to Refined Petroleum Products ("RPP's") used for transportation such as gasoline, diesel, and jet fuel. Consumption of natural gas in Canada fell in early 2020, but not as significantly as RPP consumption.[20] U.S. and Canadian natural gas demand is expected to decline due to the slowdown in economic activity in 2020. Gas demand from the residential sector increases slightly while the commercial demand continues to fall with some recovery starting in 2021. The decline in industrial demand in 2020 included a significant reduction in refinery demand for natural

[18] ICF Q4 2020 Natural Gas Strategic
[19] CER – Canada's Energy Future 2020
[20] CER – Canada's Energy Future 2020

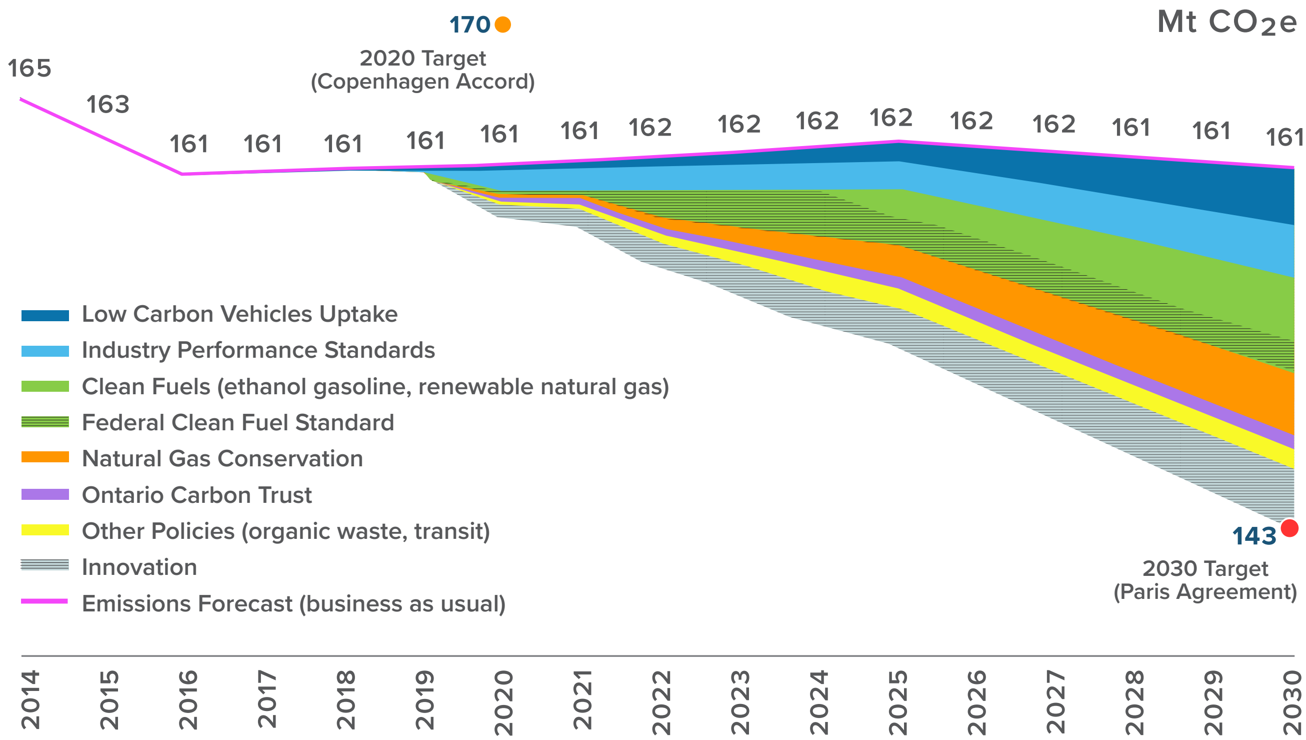
Preserving and Protecting our Environment for Future Generations

A Made-in-Ontario Environment Plan

Ministry of the Environment,
Conservation and Parks

Ontario

Path to Meeting Ontario’s 2030 Emission Reduction Target



The chart above shows where we expect Ontario’s emissions to be if we take no action (161 megatonnes) compared to where we expect our emissions to go if we take actions in specific sectors. Our target is equivalent to 143 megatonnes in 2030 and we will need reductions in key sectors identified in the graph to get there.

The coloured portions of the chart above refer to emissions reductions we expect to see from actions in this plan and the shaded portions represent the potential we have to enhance some of those actions.

The actual reductions achieved will depend on how actions identified in our plan are finalized based on feedback we get from businesses and communities. The estimated reductions are explained in more detail below.

The **Low Carbon Vehicles** uptake portion refers primarily to electric vehicle adoption in Ontario and in small part to the expansion of compressed natural gas in trucking.

Industry Performance Standards refer to our proposed approach to regulate large emitters of greenhouse gas emissions, as described later in this plan. The final impact of this approach will depend on consultation with industry partners.

Clean Fuels refer to increasing the ethanol content of gasoline to 15% as early as 2025, and encouraging uptake of renewable natural gas and the use of lower carbon fuels.

The Federal **Clean Fuel Standard** is an estimate of the additional impact of the proposed federal standards, which could expand the use of a broad range of low-carbon fuels, energy sources and technologies, such as ethanol, renewable natural gas, greener diesel, electricity, and renewable hydrogen.

The Natural Gas Conservation action reflects programs that are well established in Ontario to conserve energy and save people money. This case assumes a gradual expansion of programs delivered by utilities, which would be subject to discussions with the Ontario Energy Board.

2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study

Prepared for

Submitted: 2019-09-13

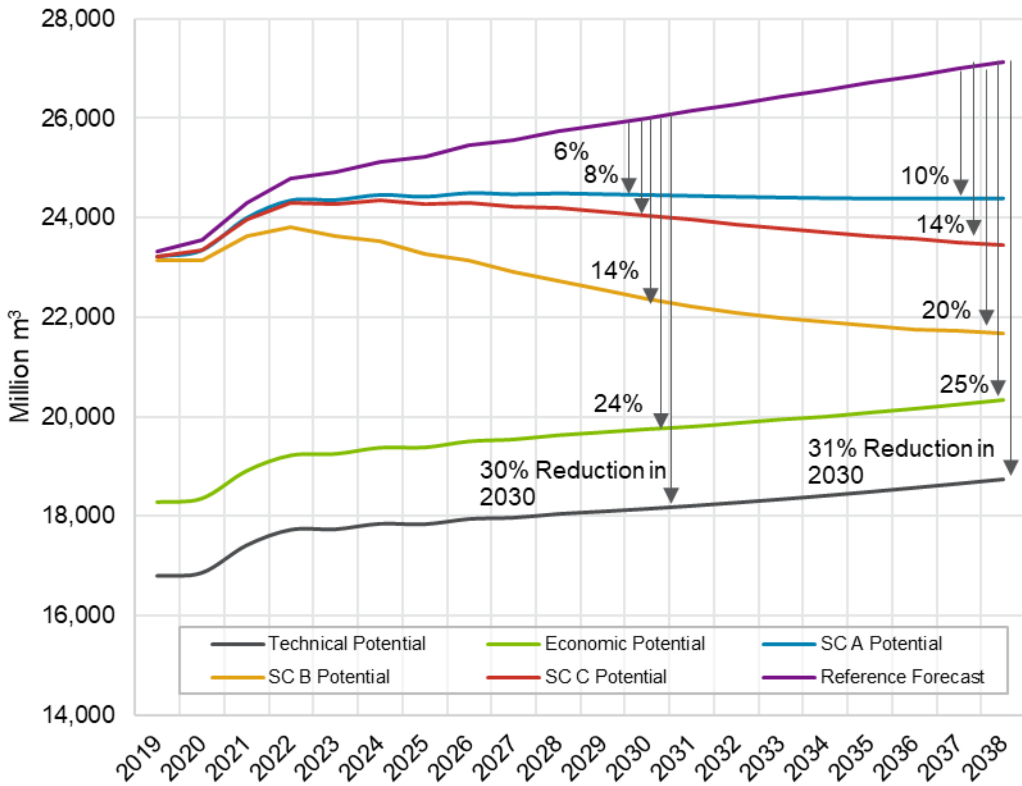
Prepared by:

Navigant
100 King Street West | Suite 4950
Toronto, ON M5X 1B1

416.777.2440
navigant.com

Growth in the natural gas reference forecast is driven predominantly by growth in industrial sector consumption (27% between 2019 and the end of 2038). Growth in the residential and commercial sectors' reference forecast in the same period is 9% and 11%, respectively.

Figure ES-6. Natural Gas Potential – Compared with Reference Forecast



Source: Navigant analysis

Comparison of Potential Across Sectors and Scenarios

This section provides a summary of the potential savings opportunities in each sector.

Electricity Potential by Sector

Figure ES-7 shows the total achievable annual electric energy savings potential in 2038 for all measures installed over the potential reference forecast period broken down by sector and scenario. By 2038, Scenarios B, C, A, and D reach 82%, 69%, 62%, and 59% of the economic potential, respectively.

As part of our mandate, we set the rates for the gas you use for your home or business if you're a customer of Enbridge Gas, Union Gas and EPCOR Natural Gas Limited Partnership. We also approve the rates these utilities charge to deliver natural gas to you. We do not set rates for Kitchener Utilities or Utilities Kingston.

We also **do not** regulate the prices that natural gas marketers charge in their contracts. Or what companies charge to rent, repair or maintain water heaters.

See a description of all of the charges that appear on your natural gas bill

Current gas rates for supply

January 1, 2021 natural gas rates (view detailed rates below)	
Union Gas (South) *	13.4224 ¢/m^3
Enbridge Gas	10.3563 ¢/m^3
EPCOR Natural Gas Limited Partnership (Aylmer) **	13.5143 ¢/m^3

** The rate for Union South includes transportation charges.*
*** The rate for EPCOR includes storage and transportation charges.*
To see how these natural gas rates relate to your overall bill, visit our ***natural gas bill calculator****.*

View past natural gas rates

How often does the Ontario Energy Board set new rates?

We set rates for the natural gas that you use (supply) 4 times a year.

Natural gas is a commodity that is traded on North American markets. Market prices rise and fall based on current supply and demand. Major weather events can also affect the market price.

Federal Carbon Charge

Natural gas is dependable and affordable energy that enhances people's quality of life and helps local business and industry prosper and grow. It continues to be the lowest-cost energy source and remains the most economical choice for home and water heating in Ontario.

What is the federal carbon charge?

In 2019, the federal government implemented a carbon pricing program in Ontario. As part of this program, a carbon charge applies to fossil fuels sold in Ontario, including natural gas. On April 1, 2020, the federal carbon charge for natural gas increased to **5.87 cents per cubic metre (m^3).** This charge will increase annually each April. In April 2021, the charge will increase to 7.83 cents per cubic metre. You can see how the price changes each year in the chart below.

2019 – 2022 Federal Carbon Charge Rates for Marketable Natural Gas		
Year	**$/ tCO_2e**	**cents/m^3**
2019	$20	3.91
2020	$30	5.87
2021	$40	7.83
2022	$50	9.79

There is also a facility carbon charge included in the delivery or transportation charge on your bill, which for the average residential customer will add about 12 cents annually. This charge is associated with the costs to operate Enbridge Gas's facilities.

All of the money that we collect for the federal carbon charge goes to the federal government.

What does this mean for you?

The federal carbon charge has been included on customers' bills since August 2019 and shows as a separate line item. It's forecasted that for the average Ontario household, the federal carbon charge will add about $141 to your annual natural gas bill in its second year. This will continue to change annually as the rate increases. Your total cost depends on how much natural gas you use, but can be determined by multiplying the federal carbon charge rate by the number of cubic metres of gas you used (which can be found on your natural gas bill).

Enbridge Gas began incurring costs for the Federal Carbon Pricing Program on April 1, 2019 but did not receive regulatory approval to include the charge on customer bills until Aug. 1, 2019. We recently received Ontario Energy Board (OEB) approval to recover the costs incurred in the four-month period between Apr. 1, 2019 and July 31, 2019 over a three-month period starting Oct. 1, 2020.*

The federal government has indicated Ontario residents are eligible to receive a tax-free climate action incentive payment (https://www.canada.ca/climate-action-incentive-payment) of up to $448 for an average Ontario family of four. The incentive can be claimed when you file your income tax return.

BACK TO TOP

Large business customers who may be required or eligible to register with the federal government in order to receive full or partial exemption from the federal carbon charge can find more information on our **large business customer federal carbon pricing program page** (/Natural-Gas-and-the-Environment/Enbridge-A-Green-Future/Federal-Carbon-Pricing-Program—Business).

Enbridge Gas has programs available to help you manage your energy costs

Filed: 2020-06-25
EB-2020-0066
Exhibit JT1.7
Page 1 of 1

ENBRIDGE GAS INC.

Undertaking Response to ED

To calculate a revised cost per tonne of GHG emissions that includes the GHG emissions of natural gas lost in the environment during extraction, transportation, and distribution.

Response:

As discussed in Exhibit I.PP.4, the preliminary value for the lifecycle carbon intensity of natural gas in the federal Clean Fuel Standard ("CFS"), which is currently under development, is 62 gCO_2e/MJ. This number can be broken out further to 48 gCO_2e/GJ for emissions from end-use combustion, and 14 gCO_2e/MJ related to upstream extraction, processing, transportation and distribution.[1] Based on this information, the upstream natural gas emissions represent approximately an additional 29.2% of avoided emissions, and results in an avoided cost of emissions of $262/tCO_2e$.[2]

[1] The preliminary values were taken from the report submitted by the consultant Earthshift Global to Environment and Climate Change Canada in 2019 and are intended to apply to natural gas across Canada.

[2] Methodology for calculating the $/tCO2e value is discussed in Exhibit JT1.6.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Board Staff ("STAFF")

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, p. 1

Enbridge Gas provided a table including forecast funds collected from the Voluntary RNG Program, as well as RNG Volumes (in GJ and m^3).

Question:

1. Please add new rows to this table that detail:
    a. the estimated amount of funds that will be directly used to procure RNG in each year, and
    b. the assumed settlement price ($/GJ or $/m3) of this procurement.

2. Please explain Enbridge Gas' assumptions behind the assumed settlement price for procuring RNG.

3. Please describe how Enbridge Gas' assumptions on the settlement price to procure RNG compare with the estimates in Chapter 3 of the final report for Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities (EB-2016-0359).

Response

1. a) & b)

TEN YEAR PROGRAM FORECAST

	YEAR 1	**YEAR 2**	**YEAR 3**	**YEAR 4**	**YEAR 5**	**YEAR 6**	**YEAR 7**	**YEAR 8**	**YEAR 9**	**YEAR 10**
Funds Collected	$386,090	$548,264	$590,438	$632,613	$674,787	$716,961	$759,135	$801,309	$843,483	$885,658
RNG Volumes (GJ)	22,711	32,251	34,732	37,213	39,693	42,174	44,655	47,136	49,617	52,098
RNG Volumes (m^3)	609,863	866,032	932,649	999,267	1,065,885	1,132,503	1,199,121	1,265,739	1,332,356	1,398,974
% of Funds used for RNG Procurement	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Assumed RNG Price($/GJ)	$21									

2. Enbridge estimated the RNG price to be $21 per GJ, and the traditional natural gas price to be $4 per GJ. Since RNG volumes will replace traditional natural gas volumes, the incremental cost of RNG is $17 per GJ. Please also see Exhibit I.STAFF.4 1).

3. The Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities (EB-2016-0359) assumes the following levelized cost of energy (LCOE) ranges for RNG, based on various sources of feedstock. Enbridge Gas's estimated RNG price of $0.78 per m^3 falls within the LCOE ranges for all feedstock, and is lower than the combined average of LCOE for all potential feedstock referenced below.

Table 22 Summary of the National and Ontario Provincial RNG Potential in 2028 by Feedstock

Feedstock	National Potential by 2028 (million m^3/yr)	National Potential by 2028 (tCO_2/yr)	Ontario Potential by 2028 (million m^3/yr)	Ontario Potential by 2028 (tCO_2/yr)	LCOE ($/$m^3$)	Notes
Landfill gas	290	540,000	113	210,000	$0.33-$0.82	Evaluated 5 different sized facilities based on survey referenced in Canadian Biogas Study; linked to study for Environment Canada
WWT gas	180	340,000	71	135,000	$0.48-$3.73	Evaluated 4 different sized facilities – ICF analysis
Animal manure	874	1,640,000	191	360,000	$0.87-$1.66	Considered 3 different farms (Electrigaz study): baseline, large, and co-op
SSO residential & commercial	300	560,000	110	210,000	$2.90	Assumed a single facility capable of processing 60,000 tonnes/yr per Canadian biogas study. Larger/smaller facilities conceivable

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 15-18

Preamble:

Enbridge states at page 17 of the reference:

> "To support this pilot project, Enbridge Gas has arranged to procure hydrogen from 2562961 Ontario Ltd. in a manner that keeps ratepayers cost-neutral. This treatment would apply to the hydrogen supply for the BGA until rebasing or until such earlier time that a different treatment is appropriate based on future developments; for example, the implementation of a CFS."

Question:

(a) Please estimate the cost per m3 and GJ of hydrogen produced by 2562961 Ontario Ltd.
(b) Please explain the relationships between 2562961 Ontario Ltd, Hydgrogenics Corporation, the IESO, and Enbridge. Please provide all contracts between any of those parties relating to this pilot project or the power-to-gas plant.
(c) How much does 2562961 Ontario Ltd pay for electricity and how much is it forecast to pay for electricity over the next 10 years?
(d) Will the provision of hydrogen at the rates proposed by Enbridge result in losses or profits for any of the entities described in (b)? Please explain and estimate the quantum of any losses or profits.
(e) Please provide a table showing Ontario's annual surplus electricity (kWh), historic and forecast, from 2010 to 2040.
(f) Hydrogen is less expensive if generated with surplus power. What is the hydrogen generation potential from surplus power between now and 2040 (m3 and GJ)?
(g) Please provide a best estimate of the cost at which hydrogen can currently be produced in Ontario (per m3 and GJ) via power-to-gas. Please include and separately itemize the cost of electricity and the cost of converting electricity to hydrogen. Please make all assumptions as necessary and state all assumptions.
(h) If technological advancements are expected, please provide a best estimate of the cost at which hydrogen could be produced in Ontario in 2030 (per m3 and GJ) via power to gas. Please include and separately itemize the cost of electricity and the

cost of converting electricity to hydrogen. Please discuss and provide a qualitative answer if a quantitative one is not possible.

(i) What is the going market rate for hydrogen in Ontario (per m3 and GJ)? If a single rate cannot be provided, please provide a range and some examples.

(j) What is the going market rate for hydrogen in Ontario (per m3 and GJ) *created from power-to-gas*? If a single rate cannot be provided, please provide a range and some examples.

(k) What is the going market rate for hydrogen in California (CAD per m3 and GJ)? If a single rate cannot be provided, please provide a range and some examples.

(l) What is the going market rate for hydrogen in California (CAD per m3 and GJ) *created from power to gas*? If a single rate cannot be provided, please provide a range and some examples.

(m) What is Shell Canada charging for hydrogen in its hydrogen refuelling stations in Quebec? An average, approximate, or point-in-time answer is sufficient. Would this hydrogen be mostly from natural gas reforming or power to gas?

(n) What is the percentage difference between the current cost for hydrogen and natural gas in Ontario of the same heating value (for hydrogen created via power to gas)? Please provide the forecast difference between now and 2040, both annual and average over that period? Please provide the underlying calculations.

<u>Response:</u>

(a) Please see Exhibit I.STAFF.2(d) for a description of the price to be paid by Enbridge Gas to purchase hydrogen from 2562961 Ontario Ltd. and a copy of the associated term sheet. Enbridge Gas is not prepared to disclose 2562961 Ontario Ltd.’s costs to produce hydrogen as that information is commercially sensitive. Enbridge Gas does confirm, however, that 2562961 Ontario Ltd.’s costs to produce hydrogen are higher than the price to be paid by Enbridge Gas to purchase hydrogen. That is consistent with the information provided below in the response to (g) regarding a hypothetical hydrogen plant.

(b) Please see Exhibit I.CCC.11 for a description of the relationship between Enbridge Gas, Enbridge Inc., 2562961 Ontario Ltd and Hydrogenics Corporation. Please see Exhibit I.CCC.2 for a copy of the intercorporate services agreement between Enbridge Gas and 2562961 Ontario Ltd. Please see Exhibit I. STAFF.2(d) for a description of the price to be paid by Enbridge Gas to purchase hydrogen from 2562961 Ontario Ltd. and a copy of the associated term sheet.

As explained at Exhibit B, Tab 1, Schedule 1, page 5, there is a contract with the IESO for the provision of regulation service from the Power to Gas plant (which is owned by 2562961 Ontario Ltd.). Please see Exhibit I.SEC.9.

(c) Enbridge Gas does not believe that this question is relevant.

(d) As noted above, the price paid by Enbridge Gas to 2562961 Ontario Ltd. is lower than cost. As a result, there will be a loss to 2562961 Ontario Ltd. Enbridge Gas does not believe that the quantum is relevant.

(e) Enbridge Gas is not in possession of the requested information and has been unable to find the information through review of the IESO website.

(f) Enbridge Gas is not in possession of the requested information and has been unable to find the information through review of the IESO website.

(g) There are a number of factors which will determine the cost of hydrogen production by electrolysers in Ontario including the scale of the plant and time of day that the plant runs. Using a scenario of running a new 20MW Power-to-Gas plant during off-peak hours at an average delivered price of electricity in the range of \$0.038/kWh to \$0.044/kWh, the estimated cost for producing hydrogen over the life of the plant would be as follows:

- \$44 to \$55 per GJ
- \$0.56 to \$0.70 per m^3

Note that this is the cost of producing hydrogen only and it does not include any costs associated with the storage and distribution of hydrogen. The amount of electricity to run the electrolysis equipment is about 4.7 kWh/m^3.

(h) Technological advances in electrolysers are expected in several areas. Larger scale plants will permit scale economies in the balance of plant equipment. Demand for renewable hydrogen increases globally is expected to drive production volumes significantly over the next decade driving the industry down the learning cost curve as the supply chain matures. Current research in membrane technology will increase the efficiency of electrolysers. Capex is certainly one of the most important drivers of the cost of hydrogen production, but as suggested in the question, the price of electricity is most important. There are many studies that have examined this question in depth; one example is the IRENA study on Hydrogen from Renewable Power.[1] It shows a projected future hydrogen production cost in Denmark under different capacity factors. In Ontario, it is expected that the generation mix will continue to have a very low carbon footprint, but a key question will be the price of electricity. Enbridge Gas agrees with published reports forecasting a significant reduction in the cost of building Power-to-Gas plants in the

[1] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Sep/IRENA_Hydrogen_from_renewable_power_2018.pdf (pg.26)

next decade and expect that the resulting reduction in the cost of producing hydrogen in Ontario will more than offset the increase in cost from higher delivered electricity prices. The Company expects that costs to produce hydrogen could see a net reduction on the order of 20%-30%.

(i) Phone calls to three separate Companies in Ontario or companies selling to Ontario provided the following prices for traditionally made hydrogen:

i. ~\$58/GJ or \$0.74/m^3
ii. ~\$62.5/GJ or \$0.79/m^3
iii. ~\$59.49/GJ or \$0.76/m^3

Note that this price covers hydrogen production, storage and delivery. The source of this hydrogen is typically Steam Methane Reforming of natural gas.

(j) Enbridge Gas is not aware of any Power to Gas facility in Ontario selling hydrogen to the market.

(k) According to the California Fuel Cell Partnership[2] and NREL[3] the going rate for Hydrogen converted to CDN dollars using ForEX:US\$1 = CDN\$1.31 is:

i. ~CDN\$(1.51 to 1.88)/m^3 or CDN\$(112.84 to 148.80)/GJ [
ii. ~Most common price is US\$1.65/m^3 or CDN\$137.27/GJ

Note that these prices are for delivered hydrogen dispensed at pressure at a hydrogen fueling station. The Company is not aware of a going rate for hydrogen in California for injection into the natural gas grid.

(l) Enbridge Gas has not been able to find the requested information.

(m) Enbridge Gas's information is that Shell does not have any H2 stations in Quebec. Enbridge Gas understands that the only retail hydrogen station in Quebec is from HARNOIS and is located at an ESSO station in Quebec City. It is not a full Power to Gas facility like the one owned by 2562961 Ontario Ltd. The retail price observed at the pump in February 2020 was \$18.40/kg.

(n) Currently in Ontario, hydrogen produced by Power-to-Gas using electrolysis at scale is only done by 2562961 Ontario Limited. There is no market price for this hydrogen, and it is being provided to Enbridge Gas at the same price as conventional natural gas.

Using the information set out above in part (i) about the current price for traditionally

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[2] https://cafcp.org/content/cost-refill#:~:text=Long%20Answer%3A,cost%20of%20%240.21%20per%20mile.
[3] https://ww2.energy.ca.gov/2015publications/CEC-600-2015-016/CEC-600-2015-016.pdf

made hydrogen[4], one can determine the approximate percentage difference between the cost of hydrogen and natural gas. The approximate percentage difference based on natural gas at approximately $0.12/m^3 based on July 1, 2019 natural gas rates is:

$$\boldsymbol{abs}\ \frac{\left[\$\mathbf{0}.\frac{\mathbf{12}}{\boldsymbol{m3}} - \$\mathbf{0}.\frac{.\mathbf{72}}{\boldsymbol{m3}}\right]}{\$\mathbf{0.12}} * \mathbf{100}\% = \mathbf{500}\%$$

The requested “forecast difference between now and 2040, both annual and average over that period” has not been done and is therefore not available.

[4] The calculations are based on the hydrogen cost estimates in part (i), which are related to hydrogen produced by Steam Methane Reformation (SMR): Using an average of the three results in costs of delivered (non renewable) hydrogen of approximately: ($60.00/GJ or $0.72/m3).

blended natural gas to approximately 3,600 customers in Markham, resulting in reductions in GHG emissions. Enbridge Gas estimates that, for the BGA, GHG emission reductions can range from approximately 98 tons carbon dioxide equivalent (tCO_2e) to 117 tCO_2e per year.

8. Bill impacts from the LCEP are expected to be minimal. There are three cost consequences related to the Project and Enbridge Gas is proposing certain treatments of those costs to minimize the impact to customer's bills. These are:

    - Consumption Impact – This is a volumetric impact resulting from the lower heating value of hydrogen. The heating value of hydrogen is approximately 1/3 that of natural gas. Enbridge Gas is proposing to offset the Consumption Impact on customers within the BGA by including an annual rate rider that will credit customers in the BGA for the cost associated with slight increase in volumetric requirements. This treatment would apply to customers in the BGA until rebasing or until such earlier time that a different treatment is appropriate based on future developments; for example, the implementation of a Clean Fuel Standard (CFS).

    - Facilities Impact – There will be no immediate rate impact attributable to the facilities required for the LCEP. As Enbridge Gas is currently in a price cap rate setting regime, the cost of the LCEP facilities will not be included in rates until the next rebasing year. Enbridge Gas estimates that after rebasing customers can expect to see a very slight increase in their annual bill after 2024.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, Corrected

Question:

For each year shown in the table, please add lines that shown the RNG volumes as percentages of:

i) total gas throughput;
ii) total gas purchases;
iii) total general service gas consumption; and
iv) total general service system gas consumption.

Response

Please see table below.

TABLE 1

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
Funds Collected	$386,090	$548,264	$590,438	$632,613	$674,787	$716,961	$759,135	$801,309	$843,483	$885,658
RNG Volumes (GJ)	22,711	32,251	34,732	37,213	39,693	42,174	44,655	47,136	49,617	52,098
RNG Volumes (m^3)	609,863	866,032	932,649	999,267	1,065,885	1,132,503	1,199,121	1,265,739	1,332,356	1,398,974
RNG Volume as a Percentage of Total EGI Demand[1]	0.003%	0.004%	0.005%	0.005%	0.005%	0.006%	0.006%	0.006%	0.007%	0.007%
RNG Volume as a Percentage of Total EGI Purchases[2]	0.004%	0.006%	0.007%	0.007%	0.008%	0.008%	0.009%	0.009%	0.010%	0.010%
RNG Volume as a Percentage of General Service Demand[3]	0.004%	0.005%	0.006%	0.006%	0.007%	0.007%	0.007%	0.008%	0.008%	0.009%
RNG Volume as a Percentage of General Service[4] **System Demand**	0.005%	0.007%	0.007%	0.008%	0.008%	0.009%	0.009%	0.010%	0.010%	0.011%

[1] As per EB-2020-0135
[2] Ibid.
[3] Ibid.
[4] Ibid.

Final Report

Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities (EB-2016-0359)

July 20, 2017

Submitted to:
Ontario Energy Board

Submitted by:

ICF
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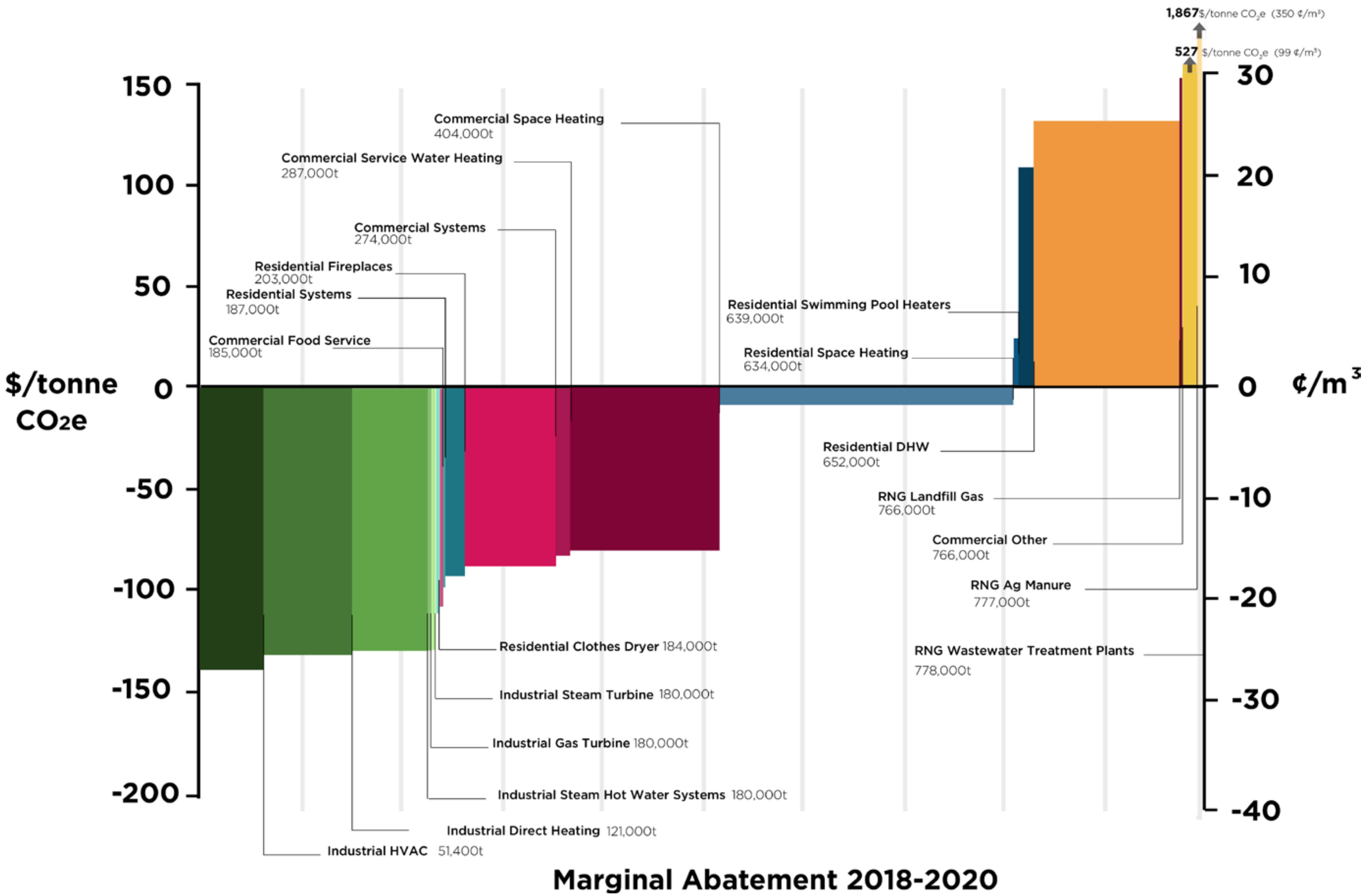
Exhibit 3 Summary MACC Including Customer Conservation Measures and RNG Potential for Mid-Range LTCPF



ICF used the RNG production estimates from the Canadian Biogas Study to develop the abatement potential estimates through 2028. While the study does not explicitly indicate the timeframe by which the resource can be developed, ICF assumed that the production potential is limited by investment rather than technological development. In that regard, ICF assumed that nearly 100% of the RNG production potential estimated in the Canadian Biogas Study is achievable by 2028 for each feedstock. The table below shows the annual RNG production potential for pipeline injection used in the analysis, in units of million cubic metres.

Table 17 RNG Resource Potential in 2028 for Canada and Ontario

Feedstock for RNG	Canada Resource Potential Estimate (million m^3/y)	Ontario Resource Potential Estimate (million m^3/y)
LFG	290	113
WWT gas	180	71
Animal manure	874	191
SSO (Residential and Commercial)	300	110
Agricultural residue	774	142
Total	**2,418**	**627**

RNG Production and Cost

ICF considered RNG production via two conversion technologies: anaerobic digestion or thermal gasification.

- Anaerobic digestion is the process whereby microorganisms break down organic material in an environment without oxygen. In the context of RNG production, the process generally takes place in a controlled environment, referred to as a digester or reactor[32]. When organic material is introduced to the digester, it is broken down over time by microorganisms, and the gaseous products of that process contain a large fraction of methane and carbon dioxide.
- Thermal gasification describes a broad range of processes whereby a carbon-containing feedstock is converted into a mixture of gases referred to as synthetic gas or syngas, including hydrogen, carbon monoxide, steam, carbon dioxide, methane, and trace amounts of other gases (e.g., ethane, hydrogen sulfide, and nitrogen). The process occurs at high temperatures (650-1350°C) and varying pressures (depending on the gasification system). There is limited commercial-scale deployment of thermal gasification technologies.

ICF made the simplifying assumption that RNG production from LFG, wastewater treatment plants, animal manure, and SSO would occur via anaerobic digestion. It was also assumed that agricultural residue would be converted to RNG via thermal gasification[33].

The main cost components considered in ICF's analysis include:

[32] The exception is landfill gas – anaerobic digestion takes place within landfills; the resultant gases would migrate to the surface and be released to atmosphere in the absence of gas collection equipment.
[33] This division of feedstocks between the two conversion technologies considered in this study was done to reduce the number of assumptions needed to estimate the potential for each feedstock.

Costs								

The table above illustrates the capital costs associated with different home heating technology deployments. Overall we have been conservative on the price of the ASHP technology (so as not to overestimate the cost) and we have assumed a standard ASHP technology deployment rather than a cold climate ASHP that would come with improved performance and higher cost. The base case represents the conventional gas fired furnace and hot water, and electric driven A/C. The ASHP scenario replaces the conventional heating and cooling with an ASHP (hot water remains natural gas storage tank type). The ASHP + HPWH is a full electrification scenario that also assumes that hot water is provided via an electric heat pump water heater, a stand-alone unit which is not connected to the ASHP. The integrated solution ASHP + NG assumes a natural gas fired furnace is also available and deployed to meet cold day heating requirements when the ASHP performance degrades to a low efficiency (low coefficient of performance, or COP).

The results illustrate that in most scenarios there is little delta in capital cost between the base case and the ASHP solutions.

The following table provides the assumed heating and cooling efficiencies that were used for this illustrative analysis (on an annual basis) for each scenario.

Table 29 Assessment of Abatement Cost Associated with Residential ASHPs – Annual Performance Assumptions

Scenario:	Base Case[58]	ASHP	ASHP + HPWH	Integrated ASHP + NG
Source of household heat	Natural Gas Furnace	ASHP (electric backup)	ASHP (electric backup)	ASHP with Auxiliary NG Furnace
Annual heating efficiency (% or COP)	95%	2.1	2.1	ASHP: 2.3 NG Furnace: 95% (Aux. meets 25% of annual heat demand)
Source of household cooling	Electric A/C	ASHP	ASHP	ASHP
Annual cooling efficiency (COP)	4	5	5	5
Source of household hot water	NG Storage	NG Storage	Heat Pump (HPWH)	NG Storage
Annual water heating efficiency (% or COP)	67%	67%	2.34	67%

In addition, the following assumptions were made with regard to peak day demand and performance:

- Peak demand at temperature of -26°C
- Furnace input rate of 54,200 BTU/h for an existing home and 40,000 BTU/h for a new home at peak design conditions

[58] These reflect typical efficiencies for new equipment, based on the current Ontario Building Code – they do not reflect the efficiencies of the currently installed stock of equipment in Ontario (which are lower)

- Blended COP of 1 for all-electric air source heat pump (ASHP) at peak day design conditions (includes contribution of electric resistance heating to overall heat pump performance)
- COP of 1.63 at operating peak of integrated ASHP, which occurs just above a switch-over temperature of -8°C (zero power draw on Ontario's peak design day, because the system would be running on natural gas on the coldest peak design day)
- Water heating peak based on an average daily hot water usage profile, where 10% of total daily energy consumption occurs in the peak hour
- Heating profile over the peak design day based on typical variation of temperature over a cold day (based on all days under 0°C in CWEC[59] data)

Based on the above assumptions, the following table illustrates the results of the GHG abatement potential and cost ($/tCO$_2$e) analysis. Annual operating costs for the ASHP technology deployment scenarios will be up to $1,000/yr higher per home than that of the base case as a result of the high cost of electric energy in Ontario relative to natural gas.

Table 30 Assessment of Abatement Cost Associated with Residential ASHPs – The Existing Home

Type of home:		Existing Homes		
Scenario:		ASHP	ASHP + HPWH	Integrated ASHP + NG
Capital Costs (delta vs NG Base Case)		$0	+$750	-$1,000
Annual Energy Costs (delta vs NG Base Case)		+$930/yr	+$1,000/yr	+$600/yr
Total Measure Spend (= Capital Cost + Lifetime Energy Costs)		$14,000	$16,000	$7,900
Annual Emissions from NG		0.82 tCO$_2$e/yr	0 tCO$_2$e/yr	1.6 tCO$_2$e/yr
Incremental Annual Emission (Reduction=negative)	Gas-Fired Elec.	0.14 tCO$_2$e/yr	0.09 tCO$_2$e/yr	-0.19 tCO$_2$e/yr
	Zero-Carbon Elec.	-3.5 tCO$_2$e/yr	-4.3 tCO$_2$e/yr	-2.7 tCO$_2$e/yr
Incremental Emissions over Measure Life (15 yrs)	Gas-Fired Elec.	2.1 tCO$_2$e	1.3 tCO$_2$e	-2.8 tCO$_2$e
	Zero-Carbon Elec.	-52 tCO$_2$e	-65 tCO$_2$e	-40 tCO$_2$e
Incremental Electricity Consumption		+8,700 kWh/yr	+11,000 kWh/yr	+5,900 kWh/yr
Incremental Natural Gas Consumption		-1,900m^3/yr	-2,300m^3/yr	-1,400m^3/yr
Lifetime Cost of Emission Reduction	Gas-Fired Elec.	$-6,600 / tCO$_2$e	$-12,000 / tCO$_2$e	$2,800 / tCO$_2$e
	Zero-Carbon Elec.	$270 / tCO$_2$e	$240 / tCO$_2$e	$200 / tCO$_2$e

Assuming a non-emitting source of electricity, emissions can be reduced by up to 4.3 tCO$_2$e/home/yr for the typical single family home in Ontario. The cost of abatement would be up to $270/tCO$_2$e and $200/tCO$_2$e where an integrated ASHP and NG furnace is deployed. The

[59] Canadian Weather Year for Energy Calculation (CWEC)

text in red illustrates an increase in emissions where the incremental electric load is met with natural gas-fired electricity instead of non-emitting generation[60].

Within the new home the ASHP applications are more cost effective due to lower capital cost and operating costs associated with cost of energy. As such, emissions can be reduced by up to 3.3 tCO_2e/home/yr and at between \$130 to \$180/tCO_2e.

Table 31 Assessment of Abatement Cost Associated with Residential ASHPs – The New Home

Type of home:		New Homes		
Scenario:		ASHP	ASHP + HPWH	Integrated ASHP + NG
Capital Costs (delta vs NG Base Case)		-\$3,000	-\$2,250	-\$2,000
Annual Energy Costs (delta vs NG Base Case)		\$650/yr	\$570/yr	\$410/yr
Total Measure Spend (= Capital Cost + Lifetime Energy Costs)		\$6,700	\$6,300	\$4,200
Annual Emissions from NG		0.82 tCO_2e/yr	0 tCO_2e/yr	1.4 tCO_2e/yr
Incremental Annual Emissions (Reduction=negative)	Gas-Fired Elec.	0.08 tCO_2e/yr	-0.03 tCO_2e/yr	-0.15 tCO_2e/yr
	Zero-Carbon Elec.	-2.5 tCO_2e/yr	-3.3 tCO_2e/yr	-1.9 tCO_2e/yr
Incremental Emissions over Measure Life (15 yrs)	Gas-Fired Elec.	1.2 tCO_2e	-0.51 tCO_2e	-2.3 tCO_2e
	Zero-Carbon Elec.	-37 tCO_2e	-49 tCO_2e	-28 tCO_2e
Electricity Consumption		+6,100 kWh/yr	+7,800 kWh/yr	+4,100 kWh/yr
Natural Gas Consumption		-1,300m^3/yr	-1,800m^3/yr	-1,000m^3/yr
Lifetime Cost of Emission Reduction	Gas-Fired Elec.	\$-5,500 / tCO_2e	\$12,000 / tCO_2e	\$1,900 / tCO_2e
	Zero-Carbon Elec.	\$180 / tCO_2e	\$130 / tCO_2e	\$150 / tCO_2e

The integrated ASHP + NG solution could minimize the need for incremental winter peaking capacity and electric system transmission and distribution upgrades were the measure taken to an economy-wide scale. Rather than the full-electric air source heat pump (ASHP) exclusively, this option leverages ASHP efficiency for spring, fall and most winter days and integrated natural gas fired technology for extreme cold periods. This option could reduce GHG emissions by ~60% versus a home that currently heats with natural gas alone.

Assessment of commercial ASHPs was not carried out. However, the following should be considered related to commercial application.

- Commercial application of the ASHP is technically feasible and shown to be economic in markets with a more favorable energy price delta between natural gas and electricity
- ASHP units can be scaled (2-100 tons) to meet the higher demand load of larger buildings such as care homes, schools, offices, hospitals, community and public buildings

[60] A natural gas furnace is less GHG-intensive than a standard ASHP powered by electricity from gas-fired generators at low temperatures – the ASHP has a higher end point efficiency in the home, but that can be outweighed by the loss of energy in converting thermal to electrical energy at the generator as well as minor energy losses in electricity transmission which combine to determine the system efficiency

Filed: 2020-06-25
EB-2020-0066
Exhibit JT1.5
Page 1 of 1

ENBRIDGE GAS INC.

Undertaking Response to ED

To advise what Enbridge believes the best estimates are and why, including a comparison with the marginal abatement cost curve report.

Response:

The figures set-out in the table below are based on the Company's discussions with potential Ontario RNG producers. The target commissioning dates of these facilities range from 2020 to 2025.

Potential Ontario Renewable Natural Gas Production Facilities Known to Enbridge Gas				**Potential based on MACC ($10^6 m^3$)[1]**
Feedstock / Biogas Source	**Potential Number of Facilities**	**Potential Annual Production ($10^6 m^3$)**	**Estimated Annual Production ($10^6 m^3$)**	
Anaerobic Digestion & Gasification[2]	24	210	101	443
Landfill	8	161	149	113
Wastewater Treatment Plants	5	31	13	71
Totals	**37**	**402**	**262**	**627**

[1] Ontario Energy Board, "Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities" (EB-2016-0359), Table 17

[2] Enbridge Gas has combined the potential volumes for source separated organics ("SSO"), animal manure and agricultural residue as shown in the MACC to align with the Company's estimate for anaerobic digestion + Gasification. These feedstocks can be converted to RNG via Aanaerobic digestion or Gasification

(e) As discussed in detail in response to part b), Enbridge Gas believes that hydrogen has an important role to play in the transition to a low carbon economy, and does not agree that its use should only be prioritized for uses where no good alternatives to fossil fuels exist.

Several papers and studies provided in response to part b) indicate that hydrogen is one of the innovative technologies that can be used for energy system integration and GHG reductions.[49] The papers do not indicate that hydrogen should be reserved only for airplanes and ships.

(f) Enbridge Gas does not agree that low-cost hydrogen produced from surplus power is meaningfully limited. There is potential for large amounts of renewable electricity generation, from sources such as solar, wind and tidal energy.

Navigant looked into this issue and reached the following conclusion:

> **Green hydrogen**
> *Dedicated wind and solar PV generation could produce green hydrogen as the main product. Navigant found that there is large theoretical potential of offshore wind and solar PV, going beyond the estimated 2050 EU renewable power projection. This means that the technical potential for green hydrogen production is virtually limitless. However, there are considerations such as the land use change risks associated with an increase in non-rooftop solar PV and competing sea uses to offshore wind that will limit the green hydrogen potential. The costs of hydrogen based on dedicated renewable electricity can come down to about €52/MWh.*[50]

(g) See response provided to question (e).

(h) Assuming that "energetic share" means the percentage on an energy content basis of total consumption in a year, the energetic share of hydrogen in blended gas at a 20% concentration of hydrogen for a customer who had been consuming 2400 m^3 of

[49] See, for example, Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues, NREL, pg. 6; Path-to-Hydrogen-Competitiveness_Full-Study-1_Hydrogen Council; European Green Deal (link); and *Gas for Climate The Optimal Role for Gas in a Net Zero Emission energy System, March 2019* (link) ("the Navigant Study")
[50] Navigant Study, page 7.

natural gas would be approximately 6%. This percentage will vary depending on the energy content of the natural gas and the hydrogen.

(i) Assuming that "energetic share" means the percentage on an energy content basis of total consumption in a year, the energetic share of hydrogen in blended gas at a 2% concentration of hydrogen for a customer who had been consuming 2400 m^3 of natural gas would be approximately .6%. This percentage will vary depending on the energy content of the natural gas and the hydrogen.

(j) Enbridge Gas believes this pilot Project is reasonable and prudent, as it involves blending up to 2% of hydrogen, which is compatible with customers' existing equipment and will not require premature replacement of any equipment.

Enbridge Gas is not proposing to blend at or above 20% by volume hydrogen into its natural gas grid. Therefore, the cited comment is not relevant to the LCEP.

(k) Enbridge Gas has addressed the financial and technical challenges associated with the pilot LCEP. The LCEP proposal has minimal ratepayer impacts. The technical aspects of the Project have been studied by Enbridge Gas's engineering department and reviewed by the TSSA. The TSSA has indicated its support for the Project.

As explained in part b), hydrogen blending is one approach that Enbridge Gas plans to use to reduce its customers' GHG emissions. It is not the only tool that will be used, but it can contribute to GHG reductions. In the immediate term, the LCEP is a pilot project that will assess how residential customers' GHG emissions can be reduced while using their existing equipment. Expansion of hydrogen blending, both in terms of additional Blended Gas Areas and in terms of increased hydrogen blending concentration can increase the resulting decarbonisation. However, this will depend on the observations and findings from the pilot LCEP and will only happen over time (and upon future OEB approvals). Enbridge Gas will review and consider "barriers" to the expansion of hydrogen blending as part of its considerations on whether and how to proceed with future plans. Enbridge Gas believes that the pilot LCEP is a reasonable and prudent first step in this regard.

(l) Please see Attachment 2 and Attachment 3 to this Interrogatory Response.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit A, Tab 2, Schedule 1, p. 1; Exhibit B, Tab 1, Schedule 1, Attachment 1

Preamble:

Preamble: Enbridge states at Exhibit A, Tab 2, Schedule 1, p. 1 that:

> "The LCEP is a pilot project that will allow the Company to green a portion of the natural gas grid in Ontario. The experience gained through the implementation of the LCEP will position Enbridge Gas to then expand hydrogen injection into other parts of its gas distribution system, further enhancing reductions to GHG emissions across the province."

Question:

(a) Enbridge is currently planning to inject hydrogen at the rate of 2%. If hydrogen injection is expanded, what is the likelihood that this percentage could be increased? Please discuss.
(b) Page 19 of attachment 1 (Ex B-1-1) seems to suggest that the 2% limit for this pilot project is based primarily on the end-user equipment. Is that true? Please discuss.
(c) Are the concerns associated with consumer end-user equipment (e.g. flashback and overheating) mostly associated with stoves, furnaces, or water heaters?
(d) Are other jurisdictions exploring or implementing mandatory equipment standards (e.g. for new furnaces) that would allow greater percentages of hydrogen injection? Is Enbridge considering advocating for changes in this direction in Canada?
(e) What is the highest percentage of hydrogen injection in a pilot project known to Enbridge?
(f) What is the approximate highest percentage of hydrogen injection that Enbridge believes could be technically feasible?

Response:

(a) Enbridge Gas plans to inject up to 2% by volume of hydrogen into a small carefully selected portion of its natural gas distribution system. There is no current plan to increase the concentration beyond the 2% maximum amount by volume. Any likelihood of an increase at this time is speculative as it would depend on a thorough review on a case by case basis based on prudent engineering principles plus the careful consideration of important factors that could affect the resiliency of the distribution system, its integrity, its reliability and its cost effectiveness. Please also see Exhibit I.STAFF.8.

(b) Yes. The studies conducted by Enbridge Gas for the BGA focused on determining an appropriate amount of hydrogen blending concentration such that there would be no material change to the safety, operability or reliability of customer gas appliances within the BGA.

(c) The type of appliance is not a direct risk factor. Concerns related to, for example, flashback and overheating, are related to the method of combustion (for example partially pre-mixed, fully pre-mixed or diffusion style) used by an appliance. Enbridge Gas's research focused on ensuring that hydrogen blending would not change the operating parameters of combustion methods in the BGA. See response to (b) above.

(d) The Deutscher Verein des Gas- und Wasserfaches (DVGW) is a German association for gas and water standards similar to the CSA in Canada, and allows for up to 10% by volume hydrogen in natural gas in Germany. Enbridge Gas is not currently advocating for Canadian standards that would allow higher concentrations of hydrogen in natural gas distribution or appliances. Instead, the Company is focused on implementing and learning from the LCEP pilot. In the future, Enbridge Gas might advocate for such a directive if this was seen to benefit the transition to renewable hydrogen as part of the economy.

(e) At the current time, the HyDeploy demonstration project in the UK has the potential to blend up to 20% by volume into Keele University via the existing gas network. A demonstration of blended gas is taking place on part of the Keele gas network and will finish in August 2020.

(f) At this time, Enbridge Gas has only assessed existing assets and approved materials for new construction in the proposed blended gas areas to confirm they are suitable for up to 2% by volume hydrogen blending. The Company does not have a position as to the highest possible hydrogen blending percentage that would be safe and technically feasible. For discussion about how Enbridge Gas would consider a higher concentration of hydrogen blending, please see Exhibit I.STAFF.8.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 2, Page 2; Exhibit B, Tab 2, Schedule 2

Questions:

(a) The federal government has committed to "help homeowners and landlords pay for retrofits by giving them an interest-free loan of up to $40,000."[7] Has Enbridge asked the federal government whether heat pumps will qualify? If not, why not. If yes, what information did Enbridge receive?

(b) If heat pumps will qualify for the federal governments $40,000 interest free loans, does Enbridge expect this will impact its customer attachment forecast (e.g. due to customers choosing to convert to heat pumps instead of natural gas due to the lack of up-front cost for the former)? If not, why not. If yes, by how much?

(c) With respect to the savings estimates communicated to potential customers in the door-to-door survey on which the attachment forecast is based, please confirm that the costs of heating with electricity were based on resistance hearing (e.g. baseboards).

(d) Please compare the cost of (1) heating a typical residential home with natural gas and cooling it with electricity versus (2) heating and cooling it with electric air source heat pumps. Please provide the comparison over a ten-year period. Please make assumptions as necessary and state all assumptions. If the calculations are a challenge, please answer the question on a best-efforts basis and with any caveats as necessary.

[7] https://www2.liberal.ca/wp-content/uploads/sites/292/2019/09/Forward-A-real-plan-for-the-middle-class.pdf

(e) With respect to the savings estimates communicated to potential customers in the door-to-door survey on which the attachment forecast is based, please compare (i) the cost of electric heating assumed in the estimates and (ii) the cost of electric heating by heat pumps per “Szekeres, A., Jeswiet, J. Heat pumps in Ontario. Int J Energy Environ Eng 10, 157–179 (2019)”.[8] Please provide the comparison on an annual basis and over a 10 year period.

(f) With respect to the savings estimates communicated to potential customers in the door-to-door survey on which the attachment forecast is based, please compare (i) the cost of electric heating assumed in the estimates and (ii) the cost of electric heating by heat pumps per “IESO, *An Examination of the Opportunity for Residential Heat Pumps in Ontario*, March 6, 2017”.[9] Please provide the comparison on an annual basis and over a 10 year period.

Response:

(a) Enbridge Gas is not aware of any details related to the federal government loan program referenced in the question. Once the program details are available for consultation, Enbridge Gas will explore alignment opportunities with its existing conservation programs.

(b) It is Enbridge Gas’s understanding that qualifying product details have yet to be released along with other important details related to the government announcement and as such Enbridge Gas cannot estimate the impact.

(c) Prospective customers who reported using a heat pump for home heating were provided with different cost saving estimates through the survey than those with electric resistance heating.

(d) The cost to operate a heat pump, particularly a geothermal system, is difficult to estimate without knowing the specific control systems in the home or details of the installation. In order to avoid misleading survey respondents, the survey provided prospective customers using a heat pump for home heating with a very high-level estimate of possible cost savings, which was $350 per year without the System Expansion Surcharge (“SES”). With the SES estimated to cost an average home an additional $500-$600/year in the survey, it was made clear that savings could be negative.

[8] https://link.springer.com/article/10.1007/s40095-018-0292-6
[9] http://www.ieso.ca/-/media/files/ieso/document-library/conservation-reports/an-examination-of-opportunity-for-residential-heat-pumps-in-ontario.pdf?la=en

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit B, pp. 23-24

Preamble:

> "Non-gas alternatives primarily include electrically powered geothermal heat pump systems and electric air source heat pumps ("EASHP"). …Enbridge Gas notes that it could offer these alternatives if authorized by the OEB, to reduce peak period demand in targeted areas. … Both electric GSHPs and EASHPs provide a solution that could be deployed to mitigate the need to build new infrastructure or to reduce the amount of new infrastructure required."

Question**:**

(a) What is the annual average coefficient of performance (i.e. efficiency) in a climate similar to Ontario's for the most efficient electric cold climate heat pump on the market? Please provide underlying information sources and studies. If Enbridge does not know which is the most efficient, please provide alternative information.

(b) Please provide all studies in Enbridge's possession on the cost-effectiveness and energy efficiency of electric heat pumps, including cold climate electric heat pumps.

(c) Please comment on the conclusions made here: https://rmi.org/heat-pumps-a-practical-solution-for-cold-climates/.

(d) Please compare the annual operating costs for space heating, water heating, and cooling for (i) a gas furnace, gas water heater, and electric air conditioner and (ii) all services provided by a cold climate air-source heat pump. Please provide the comparison over the next 10 years, including the federal governments increasing carbon price to $150 in 2030. Please make and state assumptions as necessary. Please cite all sources.

(e) How many tonnes of CO2e is produced by the average residential customer through consumption of natural gas?

(f) How many tonnes of CO2e is produced by the average residential customer with gas space and water hearing through consumption of natural gas?

(g) With respect to the OEB's July 20, 2017 MACC Report, please provide a copy of Table 30 and Table 31 (pages A-4 and A-5) that is based on the latest cold climate heat pumps.

Response:

a) The annual coefficient of performance ("COP") of Cold Climate Air Source Heat Pumps ("CCASHPs") in climates similar to Ontario is reported to be in the range of 2.5 to 2.75.[1] The Heating Season Performance Factor ("HSPF") (HSPF= Energy-out/Energy-in, BTU/Watt) of the most efficient CCASHPs are above 10, The COP of the units at -15°C are greater than 2.0 and the units maintain their maximum capacity at 15°C greater than 70% of their rated capacity at 8.3°C. There is a CSA standard EXP09 (under publication) for performance testing of CCASHPs. Northeast Energy Efficiency Partnerships ("NEEP") also lists all of the manufacturers that follow the set standards for CCASHPs.[2] Enbridge Gas is not in a position to comment on which model is the most efficient since performance of a heat pump is dependant on a number of factors including equipment selection and design, heat pump sizing, operating parameters and weather conditions throughout the year.

b) Enbridge Gas has supported a few studies to evaluate the performance of cold climate air source heat pumps. Results of a pilot study including 7 homes equipped with electric heat pumps were published as part of the ASHRAE 2019 conference. In addition, Enbridge Gas is supporting two NRCan studies to evaluate the field performance of CCASHP. NRCan is expected to publish results upon completion of these studies.

c) Enbridge Gas has not assessed or analyzed the conclusions or underlying study cited by ED. That said, CCASHPs could be used as an alternative for home heating and GHG reduction in Ontario, provided the marginal source of electricity used to power them is primarily generated from non-emitting renewable sources. In Ontario, marginal electricity is primarily produced from natural gas fired electricity generation.

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[1] Field Assessment of Cold Climate Air Source Heat Pumps Ben Schoenbauer, Nicole Kessler, David Bohac, Center for Energy and Environment Marty Kushler, American Council for an Energy-Efficient Economy, ACEEE Summer Study on Energy Efficiency in Buildings, 2016. https://www.aceee.org/files/proceedings/2016/data/papers/1_700.pdf

[2] https://neep.org/high-performance-air-source-heat-pumps/ccashp-specification-product-list

[3] Farzin R, Nima A., Tom G., "Smart Control for Optimum Residential Fuel Switching between Natural-Gas and electricity" ASHRAE transactions 1 (Winter Conference), Feb 2020.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Preamble:

In the issues list decision, with respect to issue 6, the OEB held that “[t]he question of whether non-gas alternatives, including electricity, should be eligible as IRPAs, is included within the scope of this issue.”

> This question explores the appropriateness and cost-effectiveness of electric heat pumps as an IRPA using North Bay as an example.

Question**:**

(a) In EB-2019-0188, Exhibit I.ED.9(d), Enbridge indicated that the annual cost of heating with a heat pump would be lower than the cost of natural gas heating if the surcharge was considered. Please provide the underlying calculations. Please file a live version of the “Residential Natural Gas Conversion Savings Estimate” excel document (I.ED.7 in EB-2019-0188) with the variables that produced the result in I.ED.9(d).

(b) Please comment on the applicability of this to other areas where a surcharge would be charged.

(c) Please update the analysis (i.e. input updated variables into the savings estimate tool) based on the latest carbon pricing information from the federal government (i.e. increases to $150/t CO2e in 2030). Please indicate the difference in cost between heat pumps and gas heating. Please file a live copy of the savings tool with these updated variables inputted into it.

Response:

a) – c)
Please see the responses at Exhibit I.ED.7 a) and d).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit A, Tab 2, Schedule 1, p. 1

Preamble:

Enbridge states that:

> “The LCEP is a pilot project that will allow the Company to green a portion of the natural gas grid in Ontario. The experience gained through the implementation of the LCEP will position Enbridge Gas to then expand hydrogen injection into other parts of its gas distribution system, further enhancing reductions to GHG emissions across the province.”
>
> It also states that this project is “consistent with the environmental goals of public policy provincially and federally.”

Question:

(a) Please calculate the cost of GHG emissions reductions ($/CO2e) from hydrogen injection including only the incremental commodity costs of replacing natural gas with hydrogen created via power-to-gas. Please use Enbridge’s estimate of the cost to produce hydrogen by power-to-gas in Ontario. Please provide a table showing the underlying calculations.
(b) Please calculate the cost of GHG emissions reductions ($/CO2e) from hydrogen injection including both the incremental commodity costs (replacing natural gas with hydrogen created via power-to-gas) and the incremental capital costs (upgrades to gas distribution and transmission). For the incremental commodity costs, please use Enbridge’s estimate of the cost to produce hydrogen by power-to-gas in Ontario. For the incremental capital costs, please use Enbridge’s best estimate of the capital cost per m3 of injecting hydrogen into the gas system. Please provide a table showing the underlying calculations.
(c) Please recalculate the cost of GHG reductions in (b) but for the incremental capital costs, please use the cost per m3 of hydrogen for this pilot project. Please provide a table showing the underlying calculations.

(d) Please provide the annual forecast throughput of hydrogen for the proposed pilot project.
(e) For comparative purposes, please provide the cost of GHG emissions reductions ($/CO2e) from natural gas energy efficiency programs. Please provide an explanation if Enbridge's figures are inconsistent or out of line with those in the OEB's Marginal Abatement Cost Curve Final Report, EB-2016-0359, July 20, 2017 (which indicates a significant negative cost per CO2e for energy efficiency).
(f) For comparative purposes, please provide the cost of GHG emissions reductions ($/CO2e) from renewable natural gas. Please provide an explanation if Enbridge's figures are inconsistent or out of line with those in the OEB's Marginal Abatement Cost Curve Final Report, EB-2016-0359, July 20, 2017.
(g) For comparative purposes, please provide the cost of GHG emissions reductions ($/CO2e) from converting to geothermal instead of natural gas including only the difference in annual operating costs (i.e. commodity costs). Please base the answer on the evidence prepared by Dr. Stanley Reitsma, P. Eng. in EB-2016-0004 dated March 21, 2016 (p. 35-37) or explain why different figures are used.
(h) For comparative purposes, please provide the cost of GHG emissions reductions ($/CO2e) from converting to geothermal instead of natural gas including the difference in annual operating costs (lifetime) and incremental capital costs (including the capital costs to expand gas service to the new community). Please base the answer on the evidence prepared by Dr. Stanley Reitsma, P. Eng. in EB-2016-0004 dated March 21, 2016 (p. 35-37) or explain why different figures are used.

For each of the above, please answer the question on a best-efforts basis and with any caveats as necessary. If a portion of the historic data or forecast is impossible to provide, please explain why and answer the question over as long a time period as possible. If certain parts of the answer cannot be estimated, please explain why and provide as much of the table as possible. Please make assumptions as necessary and state all assumptions.

Response:

a) Because hydrogen will be sold to Enbridge Gas at the same price as conventional natural gas (see Exhibit I.STAFF.2(d)), there is no incremental commodity cost to replace natural gas with hydrogen for the LCEP pilot. As there is no incremental cost, there is no cost of GHG emission reduction per tonne CO_2e. If one was to assume a price of $0.55 to $0.70 per m^3 for hydrogen as indicated at Exhibit I.ED.6 (d) and assuming annual blending of up to approximately 200,000 cubic meters of hydrogen results in a reduction of 120 tCO_2e per year, the cost of GHG emission reductions from the assumed cost of hydrogen is estimated as between $925 and

$1,151 /t$CO_2$e. See Attachment 1 for calculations and assumptions.

b) The cost of GHG emission reductions from incremental hydrogen commodity costs is set out in the response to part (a) above.

Enbridge has estimated the annual maximum revenue requirement for capital recovery of system upgrades as $487,000. Assuming an annual blending of up to 200,000 cubic meters of hydrogen results in a reduction of approximately 120 tCO_2e per year, the cost of GHG emission reductions from the incremental capital cost is estimated as $4,058/t$CO_2$e. The capital cost of system upgrades expressed on a dollar per cubic meter hydrogen basis was estimated at $2.44 per cubic meter of hydrogen. This impact will be reduced if Enbridge Gas expands the LCEP to include loops S1a and S1b. Note that there is no impact from the capital additions until rebasing in 2024.

c) Refer to part (b) above.

d) The maximum estimated forecasted annual throughput of hydrogen for the proposed pilot project is ~200,000 m^3/y or ~2,400 GJ/year.

e) Please see Exhibit I.Staff.8 (d).

f) Enbridge Gas's estimation of the marginal abatement carbon cost for RNG are consistent with the MACC where the average RNG abatement cost ranged from $133 to $1,867/t CO2e. Enbridge Gas notes that the RNG abatement costs as provided in the OEB's MACC Final Report are not based on a lifecycle approach and are limited to emission reductions from the displacement of natural gas. RNG may provide further GHG reductions from the capture of methane that may have otherwise been released to the atmosphere. GHG reductions from the avoided release of methane can be quantified in various carbon offset protocols.

g) Please see Exhibit I.Staff.8 (d).

h) Please see Exhibit I.Staff.8 (d).

ENBRIDGE GAS INC.

Answer to Interrogatory from
The School Energy Coalition ("SEC")

Interrogatory

Question:

[Ex. C/2/3] Please add four lines to this forecast showing:

a. The expected delivered cost per cubic meter of RNG each year;

b. The excess of the cost per cubic meter of RNG over the expected delivered cost (including Federal Carbon Charge) of conventional system gas each year;

c. The forecast tonnes of carbon avoided each year, and

d. The effective cost per tonne of avoided carbon each year incurred by procuring RNG.

Response

a-b)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
a) RNG Delivered Cost ($/$m^3$)	$ 0.78	$ 0.78	$ 0.78	$ 0.78	$ 0.78	$ 0.78	$ 0.78	$ 0.78	$ 0.78	$ 0.78
b) Excess cost RNG ($/$m^3$)	$ 0.60	$ 0.58	$ 0.58	$ 0.58	$ 0.58	$ 0.58	$ 0.58	$ 0.58	$ 0.58	$ 0.58

c. Please see Exhibit I.STAFF.10 1).

d. The effective cost per tonne of avoided carbon is $338/t$CO_2$e for each year.

challenges from other provinces, as well as First Nations groups, are before the Supreme Court of Canada with resolution not anticipated for some time. Furthermore, even in the case of the FCPP, carbon prices are set only until 2022 with no clarity on what happens after that date. Considering this, together with the overall volatility of carbon emissions policies since 2016 summarized above it is not reasonable for Enbridge Gas, or any other party, to speculate on increases to the cost of carbon emissions going forward beyond 2022. In addition, the lack of certainty on future energy efficiency programming, and timelines for introduction of new commercialized lower carbon technologies make forecasting carbon reductions even more challenging and unreliable.

44. Looking forward, the governments of Ontario and Canada, as well as those of many other jurisdictions, have set targets to reduce greenhouse gas emissions (“GHG”) and are at various stages of developing and implementing plans intended to achieve these targets. These plans typically include a variety of measures, some of which may see an increased use of existing natural gas infrastructure such as through the increase in blending of clean fuels such as RNG and hydrogen, and increased throughput of natural gas and blended clean fuels for electricity production and compressed natural gas (“CNG”) refueling stations. These plans also consider other factors such as affordability and resiliency, whereby using existing infrastructure to achieve GHG emissions reductions may be preferable as opposed to solutions such as electrification, which may be more costly.

45. Despite the establishment of GHG emissions reductions targets by the governments of Ontario and Canada, the ultimate path to achieving such reductions remains uncertain at the time of this submission. EFG’s Report recommends that Enbridge Gas provide a long-term forecast requiring vast speculation concerning future

government policy, climate change regulations and carbon emissions pricing and how the OEB may ultimately opine on future applications dealing with solutions such as hydrogen blending, RNG, DSM, community expansion and low carbon solutions that may impact natural gas demand. Only where the information concerning such policy and initiatives is known to be certain is it reasonable to forecast. Doing so based on a variety of hypothetical assumptions at a certain point in time, as recommended by EFG, would not produce information that is helpful or relevant to the Board in its review of future applications by Enbridge Gas for approvals related to either IRP or LTC investments as it would be entirely unreliable. Developing forecasts requires an extensive investment of time and resources at a significant cost to ratepayers. It stands to reason that completing incremental forecasts based on such speculative scenarios, as recommended by EFG,[35] would cost ratepayers multiple times the cost of Enbridge Gas's current demand forecast which is based on OEB-approved methodologies.

46. Enbridge Gas's continued focus is to serve the firm demands of its customers, and ensure its assets are available to meet its customers' immediate and long-term demand requirements on an annual and Design Day basis. Enbridge Gas recognizes that those assets may evolve in nature from solely pipeline infrastructure to a combination of pipeline infrastructure and IRPAs. For either pipeline or IRPAs, Enbridge Gas must be conservative in its forecasts, especially when it comes to monetization of economic risks like climate policy beyond the next few years given the uncertainties summarized above.

47. While EFG's evidence focuses upon economic risks, it only briefly acknowledges reliability risk. One immutable aspect of reliability risk that EFG's evidence neglects

[35] EFG Report, Section 4.4.2.4.2.

to adequately address is the difference between the nature of outage risk between electrical and natural gas systems. Electrical systems are designed with an acceptable level of system outage risk, while natural gas systems are designed with a higher degree of reliability. Additionally, electrical outages are typically short in duration and the system typically re-energizes itself almost immediately after the issue causing the loss of power is resolved. Further, electrical equipment can simply be restarted by end users upon resolution. In the case of the natural gas system, if system operating pressure falls below minimum customer requirements, there may be widespread uncontrolled outages, which may result in the utility having to physically shut off each customer's gas meter. Once system operating pressures return there would need to be a process whereby the utility must manually reactivate each gas meter and relight and inspect all natural gas appliances in customer buildings. Potentially re-lighting many pieces of equipment during a peak demand period (coldest day of the year) would take a significant amount of time resulting in extensive costs and potentially carry with it other very serious consequences.[36] This important aspect of natural gas system outages must be taken into account in the development of any IRP Framework, as it drives Enbridge Gas's fundamental obligation to serve the firm contractual demands of its customers.[37]

[36] EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020, p. ES-12.

[37] The Board has previously acknowledged this risk of outage for example in its Decision on Enbridge Gas's (Union) Parkway West Project (EB-2013-0074) through which the Company sought approval to construct an Loss of Critical Unit ("LCU") compressor at Parkway West citing the elevated risk/impact of an outage on the Dawn Parkway System compared to electricity systems that serve the GTA. In its January 30, 2014 Decision the Board found at page 7 that, "The evidence clearly shows that the lack of LCU capacity at Parkway West represents a system reliability weakness in the Union system…A compressor failure at Parkway, in the absence of adequate LCU capabilities at that point, could have profound ramifications for the provision of gas service to central and eastern Ontario, as well as Quebec and other markets."

48. In terms of the broader natural gas system, all indications in the foreseeable future are that Enbridge Gas's natural gas infrastructure in Ontario will remain used and useful and the price of natural gas commodity in Ontario will remain low. This is especially true considering that development of RNG and hydrogen in Ontario and in many other jurisdictions is linked to maintaining high utilization of natural gas systems. Over time, natural gas can be blended with renewable fuels like RNG and hydrogen and paired with carbon capture and utilization technologies until such time when all or a portion of the market may be ready for 100% hydrogen.

7.0 Pilot Programs

49. In its Report, EFG states that "…the Board should require Enbridge to begin planning to deploy two such pilot projects in 2021 with actual deployment of IRPA resources beginning no later than January 2022."[38]

50. Enbridge Gas agrees in principle with EFG's proposal to develop and implement two pilot projects. Pilot projects would provide the opportunity to test a number of elements associated with IRP and Enbridge Gas's IRP Proposal/Processes, including but not limited to: the design, review and assessment of IRPAs (including new and emerging technologies); procurement methodologies/strategy for IRPAs sought from existing competitive markets; the proposed stakeholder engagement model; proposed screening mechanisms and cost-effectiveness tests; and the ability to effectively and accurately measure actual achieved results of investments in IRPAs. Enbridge Gas could then apply the learnings from those pilot projects to future IRPAs.

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[38] EFG Report, Section 4.3.2.

Enbridge
500 Consumers Road
North York, Ontario M2J 1P8
Canada

February 1, 2021

Toronto City Council
c/o Marilyn Toft
Council Secretariat Support
12th Floor, West Tower, City Hall
100 Queen St. W.
Toronto, ON M5H 2N2

Re: MM28.21 – Calling on the Province to Phase-Out Gas-Fired Electricity Generation

Dear Mayor and members of Council:

We have significant concerns with the motion to phase out gas-fired electricity generation because it ignores the practical realities of Ontario's energy system, does not offer realistic solutions, or acknowledge available, affordable low-carbon alternatives.

Ontario requires flexible generation in the electricity grid that only natural gas can provide.

- Natural gas accounts for nearly a third of the province's installed capacity and is the only energy source with the flexibility to ramp up and down quickly to meet changing electricity use on demand. Further, natural gas enables intermittent renewable electricity in times when the wind doesn't blow, the sun doesn't shine, or above-ground infrastructure is impacted by climate events.

- Today, and for the foreseeable future, electricity can't be efficiently stored. Emerging storage technologies are more expensive, can only provide energy for a set amount of time, and still rely on another source of electricity generation.

- Importing hydro electricity from Quebec is cited as an alternative to the baseload provided by natural gas, however Quebec's total generation capacity falls significantly short of Ontario's peak gas demand. Even if Ontario imported 100% of Quebec's power, we would still not meet our peak needs.

At Enbridge, we share the desire to transition to a low-carbon future. However, to achieve realistic, low-carbon solutions that are reliable and affordable, energy systems must work together, and here is why:

The infrastructure to support electrification of the baseload currently provided by natural gas, or the backup does not exist today.
Natural gas delivers almost 3.5 times as much peak energy as electricity for Ontarians across the entire province, when they need it the most. To replace the current energy provided by natural gas in Canada, would require roughly three more electric generation systems the size of Canada's current system—tripling capacity to meet peak demand. This feat would take decades

to achieve and cost over [1]$580 billion, driving up energy costs for customers. The additional cost is equivalent to increasing average Canadian household spending by 1,300 to $3,200 per year, which would present a significant hardship for many consumers at a time where we are all focusing on economic recovery.

Critical Industries can't be electrified
Electricity does not have sufficient energy intensity to power many critical technologies that our quality of life depends on like heavy transportation for the shipment of goods and steel and concrete manufacturing needed to build things like wind turbines and solar panels.

Energy systems working together can deliver less costly greenhouse gas reductions
Canada's existing natural gas and electricity systems and existing infrastructure working together can be optimized for a reliable, affordable, low emissions solution. This can be done at a significantly lower cost through a multi-grid approach that integrates natural gas solutions with the electric system rather than an electric-only option. Greenhouse gas reduction policies that entirely favour electricity over multi-grid approaches are significantly more costly [2](at $289 /tCO2 for electric alone vs $129 /tCO2 for integrated systems).

Practical, affordable low-carbon solutions exist
Immediate and affordable carbon reduction can be achieved by leveraging existing technologies and energy infrastructure:

1. **Greening the gas supply** with carbon-neutral sources including hydrogen and renewable natural gas (RNG), which are displacing traditional natural gas and reducing emissions. These technologies have the added benefits of diverting waste, leveraging existing infrastructure, stimulating regional economic development and creating local jobs [3]lower cost than electricity. Here are a few examples:
   - The Enbridge power-to-gas hydrogen plant in Markham, the first and largest of its kind in North America, is creating renewable hydrogen to balance the electrical grid and we have received approval from the provincial regulator for a pilot to blend renewable hydrogen into a portion of our grid with no cost impacts to rate payers. Successful implementation of this pilot project will support Enbridge in pursuing additional and larger scale hydrogen blending activities in other parts of its distribution system.
   - The City of Toronto has partnered with Enbridge to harvest the energy produced by organic waste to fuel the city's 150 solid waste collection trucks reducing fuel costs by as much as 20 per cent. Enbridge has also partnered with the City of Hamilton to use RNG to fuel city buses.
   - Enbridge just announced the largest RNG facility in Ontario, located at the site of Walker Environmental's landfill in Niagara Falls, which will reduce GHG emissions by 48,000 tonnes per year.
   - Enbridge took the lead on obtaining regulatory approval on a voluntary RNG program which will give customers the option to contribute $2/month for a portion of RNG blended into existing natural gas supply starting in 2021.

2. **Displacing more carbon-intensive fuels for heavy transportation** through compressed natural gas (CNG), a market-ready low-carbon alternative to diesel with up to 40 percent

[1] ICF. "Policy Driven Electrification in Canada." ICF. Oct. 2019. Web. <https://www.cga.ca/news/>.
[2] ICF. "Policy Driven Electrification in Canada." ICF. Oct. 2019. Web. <https://www.cga.ca/news/>.
[3] RNG costs $24/GJ—equivalent to $0.09/kWh (Source: cga.ca/wp-content/uploads/2020/08/RNG-Handbook-for-Municipalities-in-the-GTHA_2020-07-07.pdf); Electricity in Ontario is priced at $0.128/kWh. (Source: oeb.ca/rates-and-your-bill/electricity-rates (Rate as of September 2020))

lower fuel costs. For example, the Enbridge network of CNG fuelling stations along Highway 401 in Windsor, London and Napanee, are providing heavy-duty truck fleets with convenient access to a more affordable and cleaner-burning fuel alternative. CNG is well suited for return to base fleets like buses and garbage trucks, and when combined with RNG, can offer a zero-carbon solution.

3. **Green technologies for heat**. Opportunities exist for energy communities to partner in the development and execution of green energy technologies for heating such as highly efficient Combined Heat and Power which takes waste heat produced from the gas-fired generation of electricity and converts it to hot water or steam that can be used for heat; or Geothermal systems which use thermal energy extracted from the earth for more efficient heating and cooling. The Enbridge Gas Geothermal Program can assist customers with the installation costs and expertise.

4. **Conservation programs for homes and businesses** and investments in green technologies for home heating such as heat pumps, to help use less energy and save money. Enbridge is recognized as a leader in energy efficiency and conservation. Between 1995 and 2018, our energy efficiency programs reduced customer consumption by 28 billion cubic metres of natural gas. These gas savings have resulted in a reduction of 51.7 million tonnes of greenhouse gas emissions.

We care about our collective future and these are just some examples of the affordable, immediate and practical solutions that are shaping Ontario’s clean energy transition.

We applaud the City of Toronto’s Transform TO for its environment leadership in developing a Net Zero Strategy Plan and Enbridge looks forward to future partnerships in innovative clean energy solutions.

Sincerely,

Tracey Teed-Martin
Director Toronto Region Operations
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O:(416) 495-5138
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Why is natural gas key to Ontario’s clean energy transition?

Watch the Video
Fiona Oliver-Glasford

Net-zero emissions by 2050—that’s the goal. But we need to work together. That’s why Enbridge Gas is collaborating with governments, stakeholders, indigenous communities and other partners to find a new way forward.

You may have heard that going all-electric is the way to get to net zero, but it’s not so simple. Ontario would need to build three more electric generation systems to replace the energy natural gas currently provides—at a multi-billion dollar cost to Ontarians. Critical technologies, including concrete and steel, require an energy intensity that electricity simply can’t meet. Even renewable electricity relies on natural gas as backup when wind and sunlight aren’t available.

Here’s how Enbridge Gas is supporting the clean energy transition:

- Greening the natural gas supply with carbon-neutral renewable natural gas (RNG), and zero-emission hydrogen.
- Helping homes and businesses use less energy and save money.
- Investing in low-carbon diesel alternatives, such as compressed natural gas (CNG).
- Advancing low-carbon heating solutions, such as geothermal technology.

To achieve a cleaner future that keeps energy affordable and reliable, we’ll need a mix of energy sources and innovative solutions. Enbridge Gas is uniquely positioned to help transition to a lower-carbon economy while continuing to keep energy affordable and reliable.

Watch the video to see how Enbridge Gas is stepping up to fight climate change.

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The Voice for Clean Capitalism
Corporate Knights

Building Back Better with a green renovation wave

BY RALPH TORRIE AND CÉLINE BAK

April 22, 2020

PLANNING FOR A GREEN RECOVERY

The retrofit industry must be scaled for its "Model T moment" to help Canada's economy recover after COVID-19

Aerial view of Winnipeg after the rain.

Between our residential, commercial and institutional structures, Canada has 2.85 billion square metres of largely inefficient buildings that currently contribute to 13% of our national greenhouse gas (GHG) emissions. There is no pathway to a

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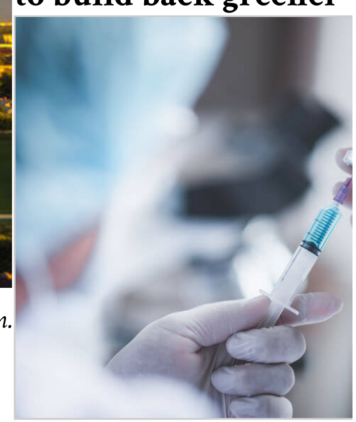


Introducing the 2021 Carbon Clean200:

low-carbon future for Canada that doesn't include both transitioning our buildings off fossil fuels and undertaking energy retrofits on a scale that's much wider and deeper than anything we have done before.

So how do we get there?

Greening our residences: Home is where the heart of GHG savings is

There are 15 million dwellings in Canada, including 10 million single-family homes and five million apartments with a combined floor area of 2.1 billion square metres.

Most of the housing that will exist 30 years from now is already standing, locking in 65 million tonnes of carbon emissions unless we intervene.

The age of a house is a much better indicator of how much it costs to heat than whether it's located in balmy Vancouver or wintery Winnipeg. Canada's existing housing stock leaks heat at several times the rate of the best new homes being built.

About two thirds of the residential-space heat is provided by fuel (mostly natural gas) and the rest by electricity (mostly electric resistance). The key to all low-carbon transitions is to combine efficiency and electrification with decarbonization of the electricity supply. A 10-year, phased-in program for thermally retrofitting and electrifying 60% of Canada's dwellings would reduce GHG emissions by 45% and annual fuel and electricity costs by $12.7 billion per year, more if prices go up.

The retrofits would include:

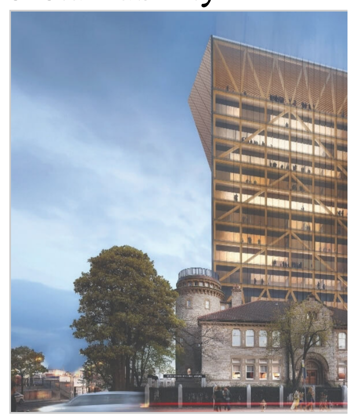
- conversion to heat pumps for space heating and water heating;
- controlled ventilation with heat recovery;
- 40 to 70% reductions in thermal leakage (depending on the type and vintage of a building); and
- a 20% improvement in lighting efficiency.

No gains from appliance efficiency are included, and air conditioning is assumed to grow by more than 70%.

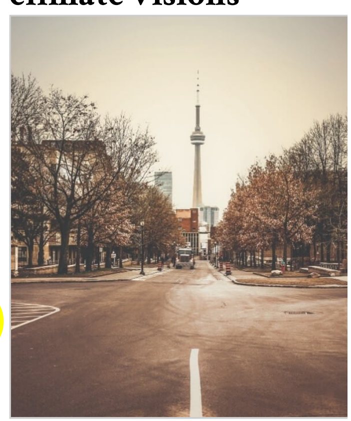
Once renovations are undertaken, Canada's consumption of electricity by the residential sector would decline, even though electricity's share of space heating would be close to triple today's. In houses that are heated with electric resistance heating, the conversion to heat pumps results in a sharp drop in electricity demand, and this, combined with the building shell and lighting upgrades, allows the existing electricity supply to more than cover the demand from all the houses converted from fossil fuel furnaces.

Investing in a Clean Energy Future

Testing grounds for sustainability



Pipe dreams and other climate visions



CHANNELS

BUILT ENVIRONMEN

The renovation industry's Model T moment

Costing an investment strategy like this in 2020 is a bit like trying to estimate what it would cost for every household to own a car in 1910, when the two innovations that would make that possible – the moving assembly line and consumer credit – were still around the corner. The going rate for a Model T was $25,000 in today's dollars, and Ford sold 19,000 of them. By 1920, the price had dropped by 80% to $5,000, and Ford sold 941,000 that year.

The housing renovation industry we have in place today could not deliver the retrofits we need for the low-carbon transition any more than Ford could have delivered 941,000 cars in 1910.

Canadians currently spend more than $60 billion per year renovating their homes (more than they spend on new homes), plus another $30 billion per year for heating fuel and electricity, resulting in 65 million tonnes of GHG emissions.

When costed at today's prevailing prices, where every job is a custom job, a deep retrofit with heat pump conversion for a single-family house costs $40,000 or more. At that rate, the capital cost for the 9.5 million dwellings included in the transition scenario here would average $36.7 billion per year over the next decade. After allowing for the savings (at today's prices), it works out to a carbon cost of $141 per tonne.

Is the equivalent of an assembly-line approach possible for the greening of Canada's existing housing stock? In "mass retrofits" or "area retrofits," many architecturally similar buildings in a common neighbourhood are systematically retrofitted. It's an idea that's gaining traction in many countries, and indications are that unit costs drop by more than 50%, sometimes much more. If the capital cost of the scenario described above were reduced by even 35%, the cost of carbon drops dramatically to $10 per tonne. The value of the retrofits also increases as the real price of fuel or electricity goes up.

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WEEKLY ROUNDUP

The retrofit industry is ripe for disruption and ready for its "Model T moment." Modern management methods, aggregation of projects and logistical genius are needed to achieve the efficiencies and economies of scale required to accelerate the pace of retrofits.

The sector also needs financing innovations and public investment in training. The homeowner should not have to bear the front-end costs and risks, let alone serve as their own general contractor. And the current practice of retrofitting in which a household routine can be disrupted for weeks or even months is unacceptable; a good target would be to limit the physical intervention in any dwelling to two days.

Greening our workplaces: commercial and public buildings

There are 750 million square metres of commercial and institutional buildings in Canada, with offices, retail outlets, hospitals and educational buildings being the four largest energy users. Annual fuel and electricity costs are $21 billion, and GHG emissions are 43 megatonnes (Mt) of carbon dioxide equivalent (CO_2e) per year. On a national basis, natural gas supplies more than 80% of the space heating needs of commercial and institutional buildings, but lights, fans, motors, pumps and a diversity of plug-in equipment keeps electricity's share of total energy over 40%.

As with the residential buildings, the key to decarbonization in these buildings is the combination of thermal retrofits and conversions to heat pumps.

In the scenario developed here, we assumed:

- 60% of the sector would be retrofitted over a 10-year period;
- a 33% improvement in the thermal efficiency of the building shells; and
- a 50% reduction in electricity used by lighting and HVAC auxiliary equipment.

Under this scenario, total electricity consumption declines by 20%, even while electricity's share of total heating grows from 10% to 60%, reflecting the same phenomenon observed in the residential buildings where the combined impact of heat pump conversions and building retrofits offset the increased share of energy provided by electricity.

The result: Energy costs will drop by a third ($7.3 billion), and GHG emissions will drop by 50%, or 22 Mt CO_2e.

At a cost of $250 per square metre for the conversions and retrofits, the 10-year program has a total capital cost of $113 billion and generates GHG reductions for a cost of -$36 and +$74/tonne.

That assumes that gas and electricity prices and the carbon intensity of the grid stay at their current levels. The decarbonization of the grid will be the subject of another article in this series.

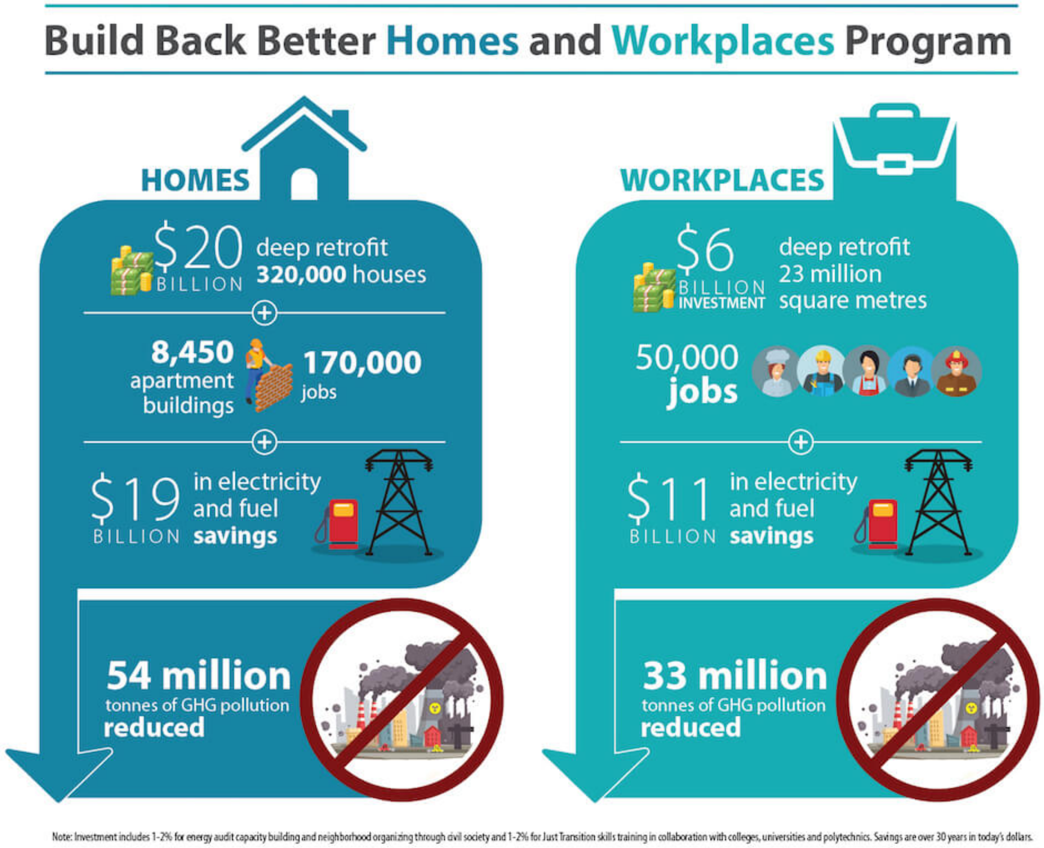
Building retrofits could power up national electric-vehicle fleet – and years of jobs

This investment in deep retrofits presents two important additional opportunities. The deep retrofit of our homes, hospitals, schools and offices would free up existing electricity capacity for the conversion of our private cars to electric vehicles (EVs). The absolute drop in electricity consumption from the combined residential and commercial building retrofit would be more than enough to power an EV fleet of 13 million, more than one EV for each of the 9.5 million households included in the retrofit scenario. Rapidly deploying EVs can help address the negative health impacts of air pollution on Canadians. And the displaced gasoline consumption would cut GHG emissions by another 48 million tonnes of CO2e annually, over and above the 58 million tonnes of direct emission reductions from the building retrofits.

Taken together, the investments in residential and commercial building retrofits and electrification described here would reduce annual fuel and electricity costs by $20 billion.

It's time to move the building renovation industry to its Model-T moment. A near-term $20 billion investment in residential building retrofits and a $6 billion investment in public and commercial building retrofits would set the wheels in motion to do that.

Targeted stimulus investment at this scale at this scale would generate **an enormous number of jobs – up to 220,000** for a wide variety of professions and skilled trades. Training and deploying the workforce needed—much of which already exists–will be critical to the implementation of these retrofits. That investment and employment would be evenly distributed throughout the country (wherever there are buildings!), an attribute that makes it an ideal candidate for stimulus financing in the post-COVID recovery period.



CANADA 2020–2030 BUILD BACK BETTER HOMES AND WORKPLACES PROGRAM

The Opportunity

Canadians are faced with unprecedented challenges as they shelter in place during the COVID-19 pandemic. But in the coming weeks and months, we will be looking at how we can reawaken an economy that has been put to "sleep" to keep us out of harm's way. Once building and construction is allowed to resume, a national program could enable Canada's home and building sector to be part of Building Back Better – for instance, by scaling up Canada's renovation industry so it can transition to a deep-retrofit industry that puts 220,000 Canadians to work over the next 12 months. This opportunity to deliver better, more climate-change-resilient homes and workplaces is also a chance to grow local manufacturing.

The estimated cost would be $20 billion for residential homes and $6 billion for workplaces. To put that in context, the residential portion represents just one-third of the $60 billion that Canadians already spend each year renovate their homes. The Build Back Better Homes and Workplaces Program will enable Canadians to save money, reduce air pollution and increase the value of their homes, all while making our dwellings and workplaces both more efficient and more resilient.

The Proposal

Build Back Better Homes: Invest $20 billion to deep retrofit over 300,000 homes in single- and multi-dwelling buildings and 8,000 apartment buildings to protect against floods and to reduce fuel and electricity costs by $19 billion over the next 20 years (in today's dollars) while reducing greenhouse gas (GHG) emissions by 54 megatonnes (Mt) over the same period. This investment would also enable homes to power electric vehicles (EVs); this would go a long way toward reducing air pollution, which has been shown to contribute to the spread of the novel coronavirus and which already represents a considerable disease burden on Canadians in the best of times.

Build Back Better Workplaces: Invest $6 billion to retrofit 23 million square metres of Canadian public and private workplaces with place flood-protection measures and to reduce fuel and electricity costs by $11 billion over the next 30 years, while reducing GHG emissions by 33 Mt over the same period. It would also help ensure that workplaces such as hotels, restaurants, hospitals and schools are better places for Canadians.

Steps for Build Back Better Homes and Workplaces

1. Federal government commits to funding for grants to Build Back Better, including:

- $20 billion for homes;
- $6 billion for workplaces;
- 1%–2% of the capital for energy-audit and local capacity building;
- 1%–2% of the capital for "just transition" skills training in collaboration with colleges, universities and polytechnics; and
- 1%–2% of the capital for loans to local manufacturing and logistics companies wanting to grow and support this market.

2. Canada Mortgage and Housing Corporation (CMHC) publishes criteria for Build Back Better Credit Insurance for Home and Property Owners. The eligibility criteria for these lines of credit and mortgage-insurance policies would include:

- conversion to heat pumps for space and water heating;
- significant improvement on the EnerGuide rating for homes or ENERGY STAR score for buildings;
- controlled ventilation with heat recovery;

- 40%–70% reduction in thermal leakage from building envelope;
- 20% improvement in lighting efficiency;
- safeguards against basement flooding; and
- installation of EV charging stations.

3. CMHC establishes a public platform on which municipalities, retrofit contractors, equipment manufacturers, utilities, energy audit firms and home and property owners can register their interest in the Build Back Better Homes and Workplaces Program.
4. CMHC establishes a public platform that shows the average cost of Build Back Better Homes and Workplaces equipment and labour, based on postal codes. This platform, which is continuously updated, publishes regional reports on equipment costs and labour shortages.
5. Homeowners apply to banks for Build Back Better loans. Loans qualifying for rebates and discounts will be covered through the CMHC Build Back Better Credit Insurance for Homes and Property Owners.

- Phase 1 loans of $40,000 (2020–21) are 100% forgivable upon providing proof of a Build Back Better Audit, including information specifying costs and installed equipment.
- Phase 2 loans of $40,000 (2022–30) benefit from lower financing rates upon providing proof of a Build Back Better Audit, including information specifying costs and installed equipment.

6. Residential property owners apply to banks for Build Back Better mortgages. Loans qualifying for rebates and interest discounts will be covered through the CMHC Build Back Better Credit Insurance for Homes and Property Owners.

- Phase 1 loans of $45,000–$2,000,000 (2020–21) are forgivable upon providing proof of a Build Back Better Audit.
- Phase 2 loans of $45,000–$2,000,000 (2022–30) will benefit from lower financing rates upon proof of a Build Back Better Audit.

7. Workplace property owners apply to banks for Build Back Better mortgages. Loans qualifying for rebates and discounts will be covered through the CMHC Build Back Better Credit Insurance for Homes and Property Owners.

- Phase 1 loans of $250 per square metre with an expected range of $6,000,000 to $60,000,000 (2020–21) are forgivable upon proof of a Build Back Better Audit.
- Phase 2 loans of $6 to $60 million (2022–30) will benefit from lower financing rates upon proof of a Build Back Better Audit.

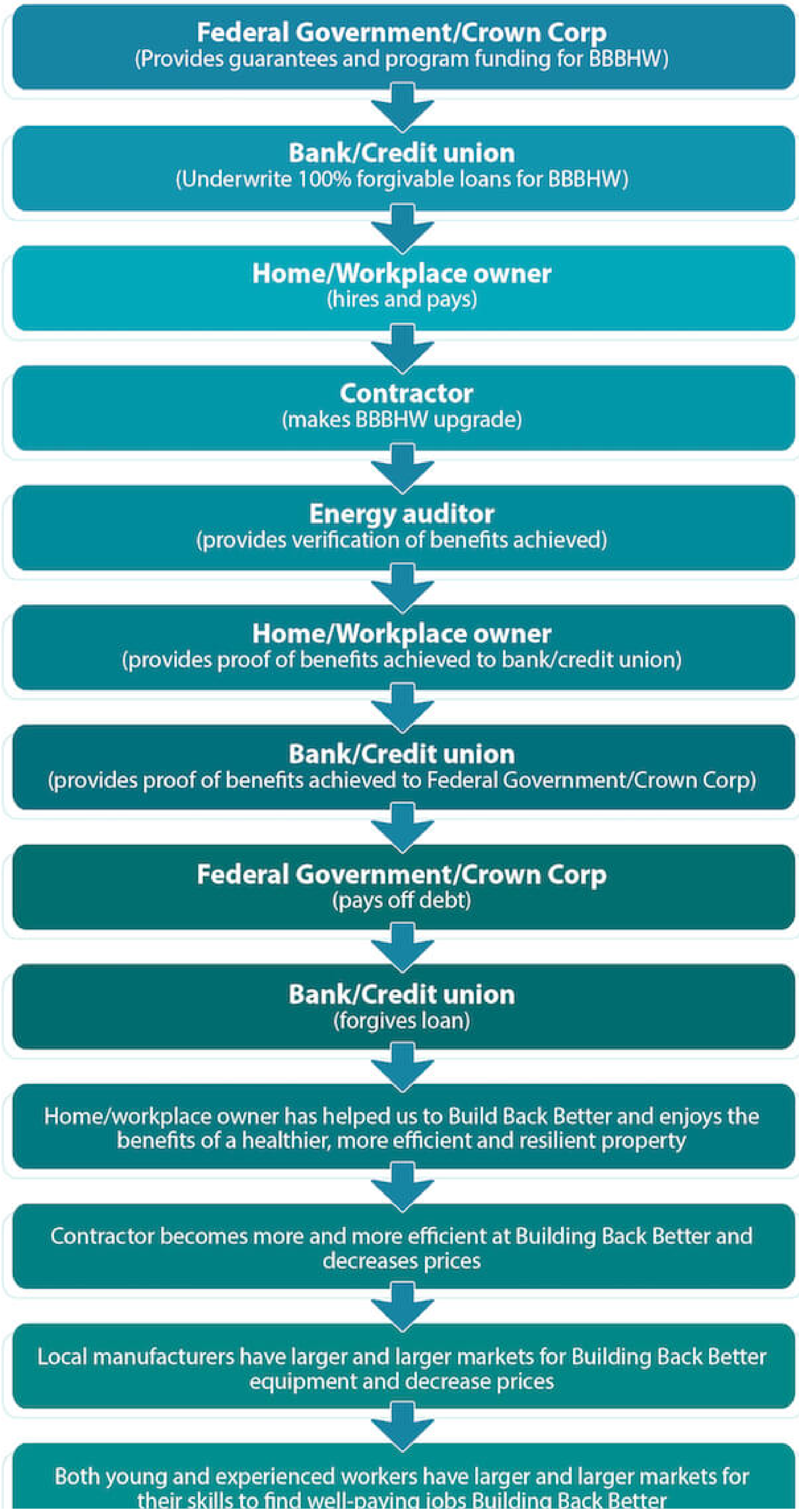
8. Banks underwrite Build Back Better loans and mortgages and sell the insurance, which requires registration with CMHC. When retrofits are complete and a Build

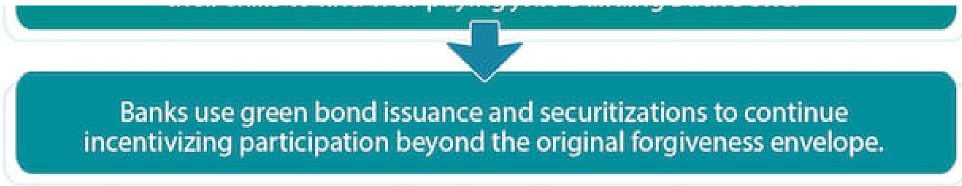
Back Better Audit is presented, banks apply to CMHC for the Build Back Better for the loan benefit.

- Phase 1 loans are repaid by the Build Back Better Homes and Workplaces federal fund administered by CMHC. Banks receive reimbursement and use it to repay the loan or mortgage.
- Phase 2 loans could receive a discount on the basis of market operations undertaken by the Bank of Canada, which assigns a preferred cost of funds (-0.25 to lower than the Bank of Canada rate) to market operations associated with these loans.

9. Banks can then use green bond issuance and securitizations to continue incentivizing participation beyond the original forgiveness envelop.

Build Back Better Homes and Workplaces Program





To learn more, explore our retrofit calculators:

CK-Residential-Retrofit-Calculator

CK Commercial Building Retrofit Calculator

Ralph Torrie is senior associate with Sustainability Solutions Group and partner at Torrie Smith Associates.

Céline Bak is the founder and president of Analytica Advisors.

With files from Toby Heaps, Aleena Naseem and Laura Väyrynen

Notice to reader: Please be aware some of the figures and other details in this white paper have been updated in the Final Report to reflect feedback.

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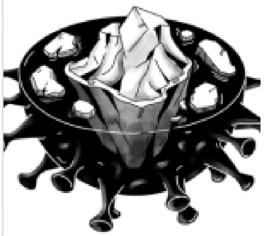

COVID has exposed the brittleness of our economic system. People and climate must be at front of the line come stimulus time

BY TOBY A.A. HEAPS

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UTILITY DIVE

BRIEF

California launches rulemaking to manage transition away from natural gas

By Kavya Balaraman

Published Jan. 17, 2020

Dive Brief:

- The California Public Utilities Commission on Thursday launched a new rulemaking to regulate the state's transition away from natural gas, addressing issues related to stranded assets and unfair cost shifts among ratepayers.
- Regulators will also look into crafting updated reliability standards for gas systems, in light of a string of safety, operational and reliability-related incidents that have plagued California's gas utilities over the last decade.
- Environmental advocates praised the rulemaking as a timely move, considering the wave of California cities adopting natural gas bans. But Jon Switalski, executive director of Californians for Balanced Energy Solutions, which represents gas users, questioned whether regulators have "carefully considered the costs to society" that would come from treating electrification as a silver bullet

Dive Insight:

California state and municipal greenhouse gas emission laws will drive down demand for natural gas over the next 25 years, according to the CPUC. The agency has also been grappling with multiple safety and operational issues on California's gas system.

In 2010, a PG&E gas pipeline exploded in San Bruno, killing eight people. Five years later, a leak was discovered at the Southern California Gas-operated Aliso Canyon storage field. And beginning in 2017, two SoCalGas pipelines have been out of service or operating at reduced pressure, leading to constraints on the system.

The operational issues also led to steep spikes in gas prices in local and wholesale electricity markets. At one point, during a heatwave in 2018, prices at a Southern California market increased from an average of $3/MMBtu to $40/MMBtu.

"The goal of this rulemaking is to provide a forum where the commission can consider the challenge of how do we ensure the safety and reliability of natural gas infrastructure in the state, as we consider this long-term strategy to manage the state's transition away from natural gas-fueled technologies to meet these decarbonization goals," CPUC Commissioner Liane Randolph said at the agency's meeting Thursday.

The rulemaking will be conducted in two tracks, with the second focused on developing this long-term strategy. Specifically, the commission intends to pinpoint what kind of gas infrastructure portfolios will be best suited for the state's utilities; how much of it is needed through 2045 and beyond; and how to address the short-term reliability need for gas in the IRP process.

In the first track of the proceeding, the commission intends to review current reliability standards, and look into rules around long-term contracting and tariff changes, among other things. Pacific Gas & Electric, San Diego Gas & Electric and Southern

California Edison are among the utilities named as respondents to the rulemaking.

"From our perspective, what was interesting and what we appreciate [the CPUC] getting ahead of is how we should be thinking about the gas system in an era of rapidly declining gas demand," Matt Vespa, staff attorney with Earthjustice, told Utility Dive.

Reaching California’s climate goals will necessitate electrifying buildings, according to Vespa, which raises questions over which customers are left to pay for the gas system and how to avoid unneeded investments. Part of the challenge will involve executing that transition without leaving behind low-income and other vulnerable customers.

"The need for this rulemaking is clear. As California reduces gas use in buildings, the pool of gas customers who are going to be footing the bill for the gas system is going to shrink," Michael Colvin, director of the Environmental Defense Fund's California energy program, said at the CPUC meeting, adding that proactively managing this transition "will be a win for both customers and for the environment."

But Switalski said that while Californians for Balanced Energy Solutions supports the state's carbon reduction goals, it differs with the CPUC on how to get there.

"We believe that pure electrification is an ideological, rather than pragmatic way to reach those carbon reduction mandates, and we believe that there should be an increasing role for renewable natural gas and eventually, one day, hydrogen," he said.

"Electrification is something that sounds good in the halls of San Francisco and Sacramento," but regulatory policy around it doesn't take into account the costs that will fall on customers, according to Switalski.

A spokesperson for the American Gas Association told Utility Dive in an email that "any realistic plan to continue toward our shared goal of emissions reductions and a clean energy future must have natural gas as a foundation."

Clarification: This article has been updated to clarify that projections of declining natural gas demand come from the CPUC. Reaching California's climate goals will necessitate electrifying buildings, according to Vespa.

UTILITY DIVE

BRIEF

San Jose, Oakland join growing list of California cities to ban natural gas construction

By Kristin Musulin

Published Dec. 4, 2020

First published on SMARTCITIES DIVE

Dive Brief:

- Both the San Jose City Council and Oakland City Council on Tuesday approved measures to prohibit natural gas infrastructure in newly constructed buildings, adding to the growing list of more than 40 California cities to pass such ordinances.
- The San Jose measure, passed in an 8-3 vote, makes it the largest U.S. city to require all-electric new construction. That measure allows a "controversial exemption" however, enabling facilities that generate and store energy on-site to continue using natural gas, according to the San Jose Mercury News. Meanwhile, the unanimously-passed Oakland measure will apply to all residential and commercial construction, though developers can apply for "technology feasibility" waivers, the San Francisco Chronicle reports.
- These measures come on the heels of San Francisco's all-electric construction ordinance passed last month. Nearly every major

Bay Area city — including Berkeley and Menlo Park — have now approved such mandates.

Dive Insight:

When San Francisco took action on natural gas construction in November, experts suggested it could hold enough weight to pressure similar legislation in neighboring cities — which it did. They also suggested such local efforts could push Gov. Gavin Newsom toward statewide action, particularly as the California Energy Commission considers updates to its building energy efficiency standards.

Newsom supports widespread climate action in the State of California but has not yet folded building electrification requirements into his statewide climate agenda. Residential and commercial buildings are responsible for about 25% of California's greenhouse gas (GHG) emissions, according to the California Air Resources Board.

And while California cities have led such measures — Berkeley made history as the first city to ban natural gas infrastructure in new buildings in July 2019 — the trend is beginning to spread across state lines.

On Wednesday, Seattle Mayor Jenny Durkan announced an energy code update proposal to ban fossil fuels in new commercial and large multi-family construction. The proposal is a a direct response to the city's building sector emissions, which increased 8.3% in Seattle from 2016 to 2018. "As Seattle's population continues to grow, the scale of our policy response to rising carbon emissions must grow even faster," Durkan said in a statement.

These West Coast cities have also suffered from out-of-control wildfires that have impacted air quality regionally. "If we want clean air, lower construction costs, savings on our energy bills, and a stable climate for decades to come, we've got to start building for that future," said Olivia Walker, research associate at the Natural Resources Defense Council (NRDC) in a statement.

Not all stakeholders agree that blanket bans on natural gas in new construction is the best solution to these challenges, however. San Jose's exemption for gas fuel cells, a last-minute addition to the proposal, is a point of contention in that city. That exemption was prompted by Bloom Energy, a publicly-traded fuel cell company based in San Jose, which argues its continuously-running fuel cells are critical for power shutoffs.

Climate advocates argue Bloom uses its cells much more frequently, pointing to a Forbes investigation that found its boxes have "been operating nonstop at Caltech for over a decade, providing nearly 30% of the power to its Pasadena campus."

"If new industrial and commercial buildings in San Jose rely on these fuel cells, it could erode some of the most significant emissions reductions from the all-electric code," an NRDC spokesperson told Smart Cities Dive. "Per Bloom's own data, the fuel cells emit between 679 and 833 pounds of CO_2 per megawatt hour. That's much dirtier than San Jose's other power sources: San Jose’s electricity supplier emits 189 pounds of CO_2 per mwh while local utility [Pacific Gas & Electric] emits 206 pounds of CO_2 per mwh."

Bloom did not respond to requests for comment from Smart Cities Dive.

While Bloom's opposition to San Jose's energy code could prompt other companies to push back on their local building electrification ordinances, climate advocates are celebrating the Bay Area's progress.

"The electrification of new buildings in California is a key first step in reducing dangerous carbon dioxide emissions in our communities and avoiding the worst impacts of the climate emergency," William Leddy, vice president of Climate Action for the American Institute of Architects, California, said in an emailed statement.

Recommended Reading:

SMART CITIES DIVE
San Francisco's gas ban on new buildings could prompt statewide action

UTILITY DIVE

BRIEF

Massachusetts attorney general urges state examine shift from natural gas heating

By Robert Walton

Published June 5, 2020

Dive Brief:

- Massachusetts Attorney General Maura Healey on Thursday called for the Department of Public Utilities (DPU) to investigate the future of the state's natural gas industry "to protect ratepayers and ensure a safe, reliable, and fair transition away from reliance on natural gas and other fossil fuels."
- Massachusetts has set a legally binding statewide limit of net-zero greenhouse gas emissions by 2050, which Healey said would require "sizeable reductions in its use of fossil fuels to achieve."
- National Grid, which delivers gas in Massachusetts, said in a statement that it "welcome[s] the opportunity to participate in an investigation into the important issues raised in the Attorney General's request" and supports the state's carbon emissions reduction goals.

Dive Insight:

Healey's call for an investigation of the gas sector follows similar actions in New York and California, which are also looking to transition away from fossil fuels. Advocates say the moves are overdue but indicate an important shift.

In January, the California Public Utilities Commission opened a rulemaking proceeding to consider challenges relating to the state's gas infrastructure safety and reliability while it pursues decarbonization. And in March, the New York Public Service Commission opened an investigation to consider issues related to gas utilities' planning procedures.

"We want the DPU to take a close look at the future of the natural gas industry in Massachusetts and make the policy and structural changes we need to ensure a clean energy future that is safe, reliable, and fair," Healey said in a statement.

Healey's petition to the DPU recommends a two-phased investigation, initially requiring Massachusetts gas companies to submit detailed economic analyses and business plans that project future gas demand in a carbon-constrained economy. Those analyses would include probable revenues, expenses and investments. The first phase should also include input from stakeholders on necessary regulatory and legislative changes, according to the attorney general.

The second phase of the investigation would focus on how to develop and carry out the necessary changes in a way that protects the state's gas consumers, according to the DPU petition.

The petition calls for regulators to consider issues of: ratepayer protection, equity and fairness; planning, forecasts and supply; and the capital investments needed to ensure a safe and reliable gas system over the next 30 years as demand declines.

Clean energy advocates say the investigation will consider how Massachusetts can transition from gas-fueled heat and power in a way that does not leave lower-income residents responsible for stranded costs. "Getting off of gas without planning is going to be messy and inequitable," Sierra Club's Massachusetts director Deb Pasternak told Utility Dive.

"Massachusetts must reduce use of natural gas to meet its important climate change goals, but that poses real threats to customers – especially low-income customers – many who can't afford to switch from natural gas to clean electricity heating systems," Charlie Harak, managing attorney of the National Consumer Law Center's Energy Unit, said in a statement.

National Grid said it supports Massachusetts' carbon emissions reduction goals and "is committed to reducing our own direct greenhouse gas emissions to net zero by 2050, expanding on our many clean energy and renewable initiatives. ... we've done extensive work on gas supply and demand forecasting, and we'll leverage these learnings in the Commonwealth."

The most customer-beneficial decarbonization pathways, said National Grid, will meet three criteria: ensuring energy safety and reliability, preserving customer affordability and adoptability, and enhancing resiliency in the face of increasing climate-related weather variability.

"The Northeast is likely to need a tapestry of solutions for heat, and our research and experience shows us that the gas network can play an integral role, using new technologies to carry zero carbon fuels like renewable natural gas, including hydrogen, or enabling geothermal districts," the utility said.

Ultimately, said Sierra Club's Pasternak, the state will transition from gas and that will cost money — with communities that can afford to pay making the transition first. The attorney general's call for an investigation is aimed at ensuring this is done equitably, she said.

"This is something we have to do, and the fact that the attorney general is creating a mechanism to do it equitably and fairly for everyone is a remarkable and important step," said Pasternak.

The next step, said Pasternak, is for the DPU to determine if it will open a new docket for the investigation.

PRESS RELEASE

AG Healey Calls on the Department of Public Utilities to Investigate the Future of Natural Gas Utilities in Massachusetts

Massachusetts Could Become Third State to Launch a Regulatory Proceeding to Proactively Manage the State's Transition Away from Natural Gas

FOR IMMEDIATE RELEASE:

6/04/2020

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BOSTON — Today, Attorney General Maura Healey has called on the Department of Public Utilities (DPU) to open an investigation into the future of the natural gas industry as Massachusetts transitions away from fossil fuels and toward a clean renewable energy future by 2050.

“In order to combat the climate crisis and meet our clean energy goals, we must transition away from fossil fuels and change the way gas utilities do business in our state,” AG Healey said. “We want the DPU to take a close look at the future of the natural gas industry in Massachusetts and make the policy and structural changes we need to ensure a clean energy future that is safe, reliable, and fair.”

In the ()petition (/doc/dpu-gas-petition/download) filed with the DPU today, the AG’s Office recognized the state’s findings that the heating sector must make sizeable reductions in its use of fossil fuels to achieve Massachusetts’s legally binding statewide limit of net-zero greenhouse gas emissions by 2050. This decline in fossil fuel demand will have profound impacts on gas distribution companies and will require them to make significant changes to their planning processes and business model. It also will require the DPU to develop new policies and structures.

Today’s petition urges the DPU to work with stakeholders to develop a nation-leading regulatory and policy roadmap that protects customers during the necessary transition away from reliance on natural gas and other fossil fuels.

“The Attorney General has called the question on which the future of New England’s economy, our global climate, and the rule of law in the Commonwealth will turn: when and how are we going to wean our energy system off of fracked gas and other dirty fossil fuels as mandated by current law?” said **Brad Campbell, President of the Conservation Law Foundation (CLF)**. “The investigation Attorney General Healey has requested is an essential first step in securing the health and future prosperity of all New England communities.”

“ELM applauds the Attorney General’s DPU petition on the future role of natural gas,” said **Elizabeth Henry, President of the Environmental League of Massachusetts (ELM).** “The science is clear that the widespread combustion of natural gas and other fossil fuels is fundamentally at odds with combatting climate change. The Commonwealth has a legally binding goal to achieve net-zero emissions by 2050, but new natural gas infrastructure projects are still being proposed by developers – and approved by the DPU. This assessment is overdue.”

“Massachusetts must reduce use of natural gas to meet its important climate change goals, but that poses real threats to customers – especially low-income customers – many who can't afford to switch from natural gas to clean electricity heating systems,” said **Charlie Harak, Managing Attorney of the National Consumer Law Center’s Energy Unit**. “We applaud the Attorney General for asking the Department of Public Utilities to investigate how we can manage this needed energy transition while still helping to ensure that all families can afford the energy they need to keep their homes warm.”

The AG’s Office recommends that the DPU conduct a two-phased investigation. The first phase should require the gas companies to submit detailed economic analyses and business plans that project the state’s future gas demand in a carbon-constrained economy, including probable revenues, expenses and investments. This phase also should include input from stakeholders on necessary regulatory, policy and legislative changes. The second phase should focus on how to develop and carry out the necessary changes in a way that protects the state’s gas consumers.

The AG’s Office urges the DPU to closely examine the following items during its investigation:

Ratepayer Protection, Equity and Fairness

As the ratepayer advocate, the AG's petition urges the DPU to consider what steps it needs to take to ensure that low-income customers are not left behind during the transition and that their rates remain affordable as gas companies' revenue requirements are spread over a shrinking customer base. The DPU also should consider policy measures to assist low- to moderate-income customers to transition their homes to clean energy.

Planning, Forecast and Supply

The DPU's investigation should consider whether the Department needs to adjust its guidelines for reviewing gas companies' forecast and supply plans to require additional data about transitioning away from natural gas as a heating fuel and for meeting future demand through demand response, energy efficiency, or other carbon-neutral options.

Capital Investments

According to the petition, the DPU should examine the investment needed to ensure a safe and reliable gas system over the next 30 years, while gas demand declines. The AG's Office also urges the DPU to examine whether there are other cost-effective alternatives to traditional gas infrastructure investment that may be better aligned with the state's climate goals.

The AG's petition points to similar actions taken in other states including New York, where the state's Public Utility Commission opened an investigation in March to ensure more useful and comprehensive planning for natural gas usage and investments in the state. California's Public Utility Commission also opened a proceeding this year to examine the challenges relating to the safety and reliability of the state's natural gas infrastructure, while the state focuses on achieving its long-term decarbonization goals.

AG Healey is committed to ensuring access to clean electricity at reasonable prices for all Massachusetts consumers.

Earlier this month, the AG's Office released a **brief** (/news/ag-healey-brief-environmental-pollution-contributes-to-disparate-impact-of-covid-19-pandemic) on the steps the state should take to address the longstanding impact of environmental injustice on Black, Latinx, and immigrant communities. These steps include investing in clean energy jobs that help build a more resilient climate and equitable communities. The brief also recommends improving energy efficiency in buildings to reduce reliance on polluting energy sources and make electricity more affordable for families across the state.

By statute, the AG's Office of Ratepayer Advocacy represents the interest of ratepayers in proceedings before the DPU. In order for the AG's request to move forward, the DPU must now approve the AG's petition and open the requested investigation. This matter is being handled by Assistant Attorneys General Jo Ann Bodemer, Donald Boecke and Division Chief Rebecca Tepper, all of the AG's Energy and Telecommunications Division.

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Attorney General Maura Healey is the chief lawyer and law enforcement officer of the Commonwealth of Massachusetts.

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UTILITY DIVE

BRIEF

Solar-plus-storage poised to become more financially attractive, but seasonal solutions remain key

By Emma Penrod

Published Dec. 1, 2020

Dive Brief:

- A mix of renewable energy and gas generation remains the most cost-effective option in most regions of the U.S, but a new report from BloombergNEF (BNEF) suggests solar-plus-storage could soon be the more financially attractive option.
- Solar-plus-storage has already begun to compete with open cycle gas turbines, and in some areas such as California combined-cycle gas generators are struggling to maintain their status as the lowest-cost generation asset. Regions with access to cheap natural gas may see slower transitions, according to the report.
- Renewable energy and battery storage could one day represent 70-80% of generation in most markets, but for 100% renewable energy, a new solution for seasonal energy storage will need to become cost competitive, according to Yiyi Zhou, a clean energy specialist at BNEF.

Dive Insight:

The U.S. energy mix has been increasingly composed of renewable energy and natural gas generation over the past decade, according

BNEF's analysis. But a shift from gas to solar and battery storage may already be in the works.

Solar-plus-storage has already begun to displace open cycle gas turbines, according to Zhou. BNEF reports that 60% open cycle turbines never ran for more than six consecutive hours in 2019. However, Zhou said combined-cycle gas generators remain the least cost option for energy generation in most regions of the U.S., at least for now.

It could take some time for solar-plus storage to begin replacing combined-cycle gas turbines (CCGTs), she said, "but it will happen in the long run."

Regulatory decisions seem to play an important role in accelerating the shift from natural gas generation to renewables-plus-storage, Zhou said, driving rapid adoption in states such as California. But other states, even those led by conservative politicians, have begun to follow California's lead, promoting the adoption of battery storage and adopting clean energy standards. As they do so and the percentage of energy generated by renewable resources increases, the price of gas generation also increases, allowing market forces to take over as the driving force behind generation trends, she said.

"As more renewables are integrated into the system, they're likely to eat into the generation hours for CCGTs, which will operate less frequently and cycle more often," Zhou said. "That will increase wear and tear and increase operating costs, making [gas generation] less economic over time."

In some cases, solar-plus-storage is already more cost effective than natural gas, leading some competitive power suppliers to invest in these projects, according to the Electric Power Supply Association (EPSA).

"Give a level, fuel-and-technology neutral playing field on which to compete, competitive power suppliers will invest in new technologies and resources to meet demand and reliability requirements when and where it is economic to do so," Todd Snitchler, EPSA president and CEO, said in a statement. "Competitive power suppliers are building competitive solar plus storage resources, investing in efficient natural gas plants, and retiring uncompetitive resources as market signals encourage them to do so."

But this cycle of decreasing renewable energy costs and increasing thermal generation costs does have an upper limit, according to Zhou. While it is technically possible to achieve a 100% renewable energy goal with today's technologies, she said, renewable energy plus batteries remain cost competitive only up to 70-80% of the total generation mix. After that point, the need for seasonal storage capacity causes the cost of 100% renewable energy to exceed the cost of a mix of renewable energy, storage and natural gas.

For 100% renewable energy to become economically feasible, Zhou said, will require additional development of technologies such as green hydrogen, carbon capture or long-duration batteries.

UTILITY DIVE

OPINION

Utility regulators wake up to the long-term risks of gas

By Mike Henchen

Published Dec. 9, 2020

The following is a contributed article by Mike Henchen, a principal on Rocky Mountain Institute's carbon-free buildings team.

Throughout this year, a subtle but meaningful shift has occurred within utility regulatory agencies across the country. Multiple states have opened official proceedings investigating the future of gas distribution in their state.

This could be the beginning of a significant trend, as key energy decision-makers are realizing the need to confront a new issue: how to plan for a major infrastructure system that may become obsolete. While several states have already begun to change electricity planning processes, this scrutiny on gas is unprecedented and encouraging.

Gas seemed like a safe bet and a reliable source of energy for many years. But as the climate, health and economic impacts of burning gas become starker, regulators will play a critical role in changing course. With new technology making it possible to switch from gas to electricity in buildings, this trend is essential to addressing the climate impact of buildings.

These early moving states acted for different reasons. In New York, a prolonged battle over National Grid's proposed gas pipeline into Brooklyn and Queens prompted regulators to change the way utilities plan new gas investments. California officials were moved to act in the wake of the massive Aliso Canyon gas leak that was discovered in 2015, along with increasing urgency to address climate change.

Now, regulators are envisioning a future with a dramatically reduced role for gas and are planning to manage that transition safely and equitably. The 2018 Merrimack Valley gas explosions forced this conversation to the forefront in Massachusetts; at the urging of the attorney general's office, gas utilities will develop a plan to transition their business.

Regulators in Colorado and Washington, DC have also taken note of this emerging trend and pursued their own action, driven largely by the need to rapidly slash carbon emissions across sectors. Both jurisdictions are rapidly cleaning up their electricity sectors and are looking to address gas burned in buildings as a critical strategy in meeting their goals of 80 to 90% emissions reduction.

These announcements are the beginning of a long process, but taken together, they demonstrate that regulators are open to changing the status quo. This is significant for a few reasons. First, the current system, predicated on burning gas in perpetuity, no longer meets the needs of society. Gas use must decline dramatically in the coming years in order to limit global warming to just 1.5° C. Regulators will have to create a new system that expands carbon-free electricity and electrification of transportation and vehicles as quickly as possible.

Second, a central tenet of regulators’ responsibility is to protect customers. As new gas infrastructure projects are approved, regulators are allowing utilities to make 50-year investments on the backs of their customers. We know now that preserving a livable climate requires transitioning off fossil fuels long before those investments will pay off. Thus, each new proposed investment now must be considered through that lens.

Finally, these state proceedings open the possibility that gas utilities might not have a viable business model in the future.The current business model depends on continued spending on gas infrastructure, and utility CEOs are starting to face questions about the electrification trend. In a future where delivering fossil fuels to millions of customers is inconsistent with a livable climate, investors need to critically assess the risks of continuing to hold equity in these businesses.

Additional states are expected to follow next year and initiate their own investigations into the future of gas. Rhode Island has already conducted an initial study of the paths to transform the heating sector. New Jersey's regulator was instrumental in developing the state's energy master plan, which envisions converting 90% of homes to electric heating.

It will become increasingly apparent in every state that today's practices are not well suited to transition the buildings sector to a zero emissions future. Regulators across the country should start by critically evaluating new gas distribution investments along with alternatives. In addition, they must stop the practice of socializing the cost of gas to new buildings, by which homebuilders get free or subsidized connections to the gas system. Not only are these unadvisable long-term investments with the potential to burden low-income customers with the long term costs of this infrastructure, but the up-front cost is higher as well; new RMI research shows that it's cheaper to build an all-electric home in every U.S. city we examined.

Regulators can also play a key role in developing markets for modern electric appliances. Modern heat pumps, for instance, are more effective and efficient than ever, but contractors and customers often aren't familiar with the technology. Regulators can accelerate the adoption of these clean energy technologies with incentives and other programs.

Finally, regulators can establish guidelines for the transition away from gas that protect both the customers who are paying into the gas system and the workers who build and maintain this infrastructure today. This transition is upon us and regulators should act now to ensure the system remains safe and reliable, that workers can transition to new clean energy jobs, and that customers pay a reasonable price for energy.

It's clear that states and cities are more motivated than ever to tackle the climate, health and economic risks associated with burning gas in buildings. That utility regulators in several key states now see themselves as participants in that crucial transition is a major step in the right direction.

Vox

The false promise of "renewable natural gas"

It's no substitute for shifting to clean electricity.

By David Roberts | Updated Feb 20, 2020, 3:43pm EST

Natural gas producers in front of a biodigester. | Shutterstock

This piece was originally published on February 14 and has been updated to include a comment from SoCalGas.

To stay in line with the targets laid out in the Paris climate agreement, the US needs to reach net-zero carbon emissions by 2050, known as "deep decarbonization." Virtually every credible study on deep decarbonization agrees on the basics of a strategy to get there.

The heart of the strategy is cleaning up the power grid, which is currently responsible for **28 percent of US greenhouse gas (GHG) emissions**. It must be rapidly transitioned to zero-carbon sources like renewables, hydro, and nuclear.

Concurrently, two of the biggest sources of GHGs, transportation and buildings, must switch over to run on that zero-carbon power. The transportation system (**29 percent** of US emissions) is almost entirely powered by gasoline and diesel; it must transition to electric vehicles to the extent possible. And buildings (also **29 percent** of US emissions) are now frequently heated and cooled by oil or, more commonly, by natural gas; they must transition to electric heating and cooling to the extent possible.

This strategy — for which I use the shorthand "**electrify everything!**" — is beginning to catch on, especially in California, which is always something of a preview of broader trends to come. In a relatively short span of time, a robust "**all-electric movement**" has emerged, as dozens of towns and cities take steps to encourage all-electric construction in new buildings.

Natural gas utilities do not like this movement one bit. The more all-electric buildings there are, the fewer natural gas ratepayers there are. An all-electric future inevitably involves the obsolescence, or at least the substantial diminution, of natural gas utilities. Naturally, they are fighting back furiously, with **astroturf groups**, PR campaigns, and lobbying at the local level.

Their main argument — playing out with particular intensity in California — has to do with "renewable natural gas" (RNG), an industry term for methane captured from biogenic (organic) waste at landfills, livestock operations, farms, and sewage treatment facilities. (It is sometimes called "biogas" or "biomethane.")

A biogas facility next to a cornfield. | Shutterstock

RNG can, depending on feedstock and circumstances, be low or even zero-carbon.

Utilities like SoCalGas **argue** that ramping up the production of RNG and blending it with normal natural gas in pipelines can reduce GHGs faster and cheaper than electrifying buildings. According to Southern California Gas Company spokeswoman Christine Detz, "A growing number of experts and industrialized nations recognize the need to include renewable gases as part of a sustainable energy mix."

By pursuing electrification, they say, regulators are pushing unnecessary cost hikes onto consumers.

It would be nice for the utilities if this were true. But it's not. RNG is not as low-carbon as the industry claims and its local air and water impacts are concentrated in vulnerable communities. Even if it were low-carbon and equitable, there simply isn't enough of it to substitute for more than a small fraction of natural gas. And even if it were low-carbon, equitable, and abundant, it still wouldn't be an excuse to expand natural gas infrastructure or slow electrification.

It isn't a close call. The research is clear: Especially in a temperate climate like California, RNG is not a viable alternative for decarbonizing buildings. It is a desperate bid by natural gas utilities to delay their inevitable decline. Policymakers would be foolish to fall for it.

That's the short version. Now let's look at how the battle is playing out, with an emphasis on California, which is one of the country's top natural gas-consuming states — and a state with a goal of going net-carbon-zero by 2050.

Electrification is gaining serious momentum in California

The expert chorus supporting electrification has been getting louder.

Energy efficiency and electrification are recommended for the building sector in the **United States Mid-Century Strategy for Deep Decarbonization**, developed under the Obama administration. They are recommended throughout the work of the **Deep Decarbonization Pathways Project** (DDPP) on various countries, including **the US**. (DDPP also did a **pathways analysis for my home state of Washington**, at Gov. Jay Inslee's behest; it contains the same recommendations.)

The California Energy Commission (CEC) has done a **report on deep decarbonization** and a (recently updated) **extensive report** on the future of the state's natural gas network. In both reports, it finds that electrification is the cheapest option for decarbonizing buildings.

In response to this chorus, **26 California cities** have now either passed an ordinance phasing out natural gas in new building construction or updated building codes to encourage all-electric construction. Dozens more cities are expected to follow suit this year. Across the state, builders and real estate developers are being pressured by their investors about "carbon risk," the possibility of building fossil fuel-reliant assets that will be unable to find buyers.

Perhaps most significantly, in January, the California Public Utilities Commission (CPUC) **announced a new proceeding** to begin the process of weaning the state off of natural gas, including consideration of a just transition to avoid safety issues and stranded costs.

The new zero-energy headquarters building of the California Air Resources Board. | CARB

Natural gas utilities are freaking out and getting shady

All this momentum has thoroughly freaked out the Southern California Gas Company, the nation's largest gas utility, serving 5.7 million customers in Southern and Central California. SoCalGas makes more yearly revenue than any other utility in the nation, and of its **$2.9 billion in revenue in 2018**, $2.25 billion, almost 80 percent, **came from residential customers**. All-electric residential construction would crush it.

Monopoly natural gas utilities run the same way **monopoly electricity utilities do**. They don't make money on the sale of gas. Rather, they charge a rate for gas that is meant to cover their costs, the costs of new investments in natural gas infrastructure, and a healthy fixed rate of return on those investments. In other words, they make profits by building stuff. Naturally, they want to build more stuff.

But what they are facing is a **steady loss of demand**, as more and more customers opt out of the natural gas system in favor of the grid. That will leave fewer and fewer customers paying higher and higher rates just to maintain the existing pipeline infrastructure, with little room left for new investments.

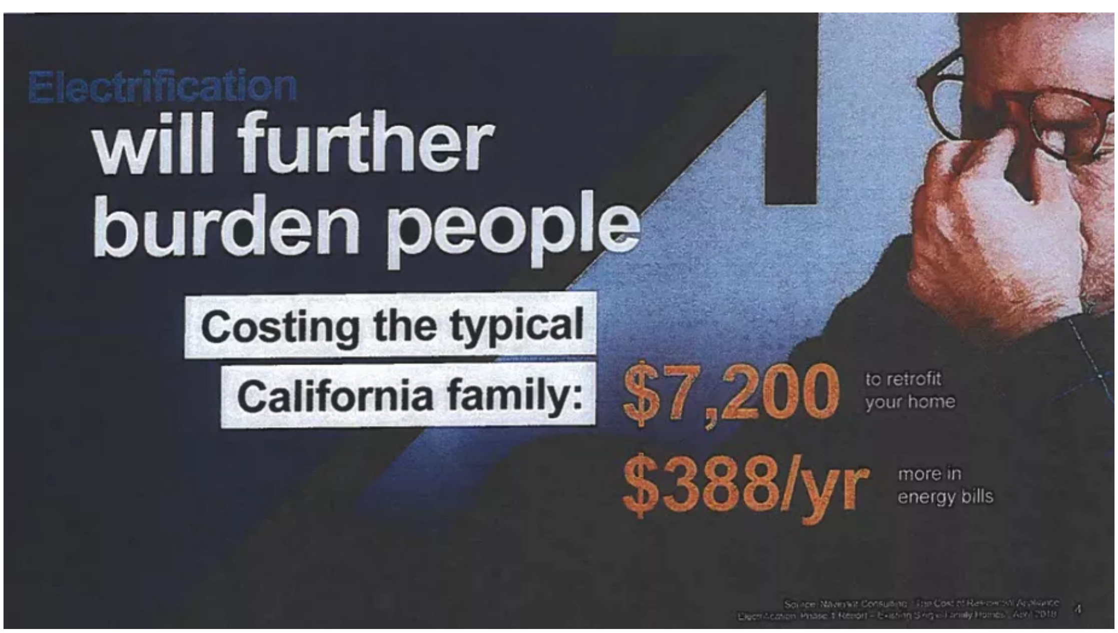
This is a disaster in the offing for SoCalGas and its owner, Sempra Energy. A few years ago, a new nonprofit was born: **Californians for Balanced Energy Solutions** (C4Bes). It began running ads opposing a natural gas phaseout and lobbying local lawmakers across the state, using **apocalyptic messaging** about the cost to consumers, recruiting local signatories for petitions against electrification. In March 2017, it had the unbridled chutzpah to ask the CPUC to make it an official party in the proceeding regarding the future of natural gas in the state.

That prompted the Sierra Club to point out, in a filing to the CPUC (replete with backing documents and leaked emails), that C4Bes is an astroturf group, a lobbying effort masquerading as a nonprofit. It's a **creation of SoCalGas**, using talking points written by SoCalGas to organize opposition to municipal efforts that would negatively impact SoCalGas. It should not be posing as an independent party in a regulatory proceeding.

Finally, after months of parrying and delaying regulators, rather than face discovery, which would open up its books, C4Bes elected in January 2019 to **withdraw from the proceeding**. In May 2019, the Public Advocates Office, a consumer watchdog within the CPUC, **determined** that SoCalGas had been using sleazy tactics, including, **reports KQED**, "lying to regulators, undermining efficiency codes and standards, and 'astroturfing': funding a seemingly independent advocacy group with ratepayer money." It recommended that CPUC sanction the utility.

Michael Boccadoro, head of Dairy Cares, an advocacy group for animal agriculture in California, was originally on the board of C4Bes until he saw their tactics up close — telling homeowners that government agents would be ripping out their gas stoves soon, crematoria that would no longer be able to cremate bodies, and Asian restaurants that have to give up their woks. "It's pretty misleading what they're trying to do," he says, "and the story they're out there telling. It seems like a desperate action." He resigned from the board last year.

(For more on this, see scathing stories from **Susie Cagle** at the Guardian and **Michael Hiltzik** at the LA Times, along with an **LA Times editorial**.)



From a presentation to city council in Brawley, California, February 2019. | Brawley

C4Bes withdrew from the proceeding, but it is still active, still out telling municipal officials horror stories about electrification. And it is not alone. In the Pacific Northwest, a coalition of gas utilities has launched a **$1 million PR effort** to push back against electrification in the region. "Partners for Energy Progress" will use much of the same messaging that C4Bes is using.

That means two things: raising fears about the costs of a transition (despite a broad consensus that electrification will save consumers money, as we will see later) and stressing consumer "choice." They know from their **research** that they can't get away with simply opposing decarbonization. They need an "all of the above" message, one that offers consumers a choice of different decarbonization pathways.

That's the role RNG is playing in this debate: The natural gas industry is proposing it as a choice, an alternate route to decarbonization.

Is it?

There isn't enough RNG to go around

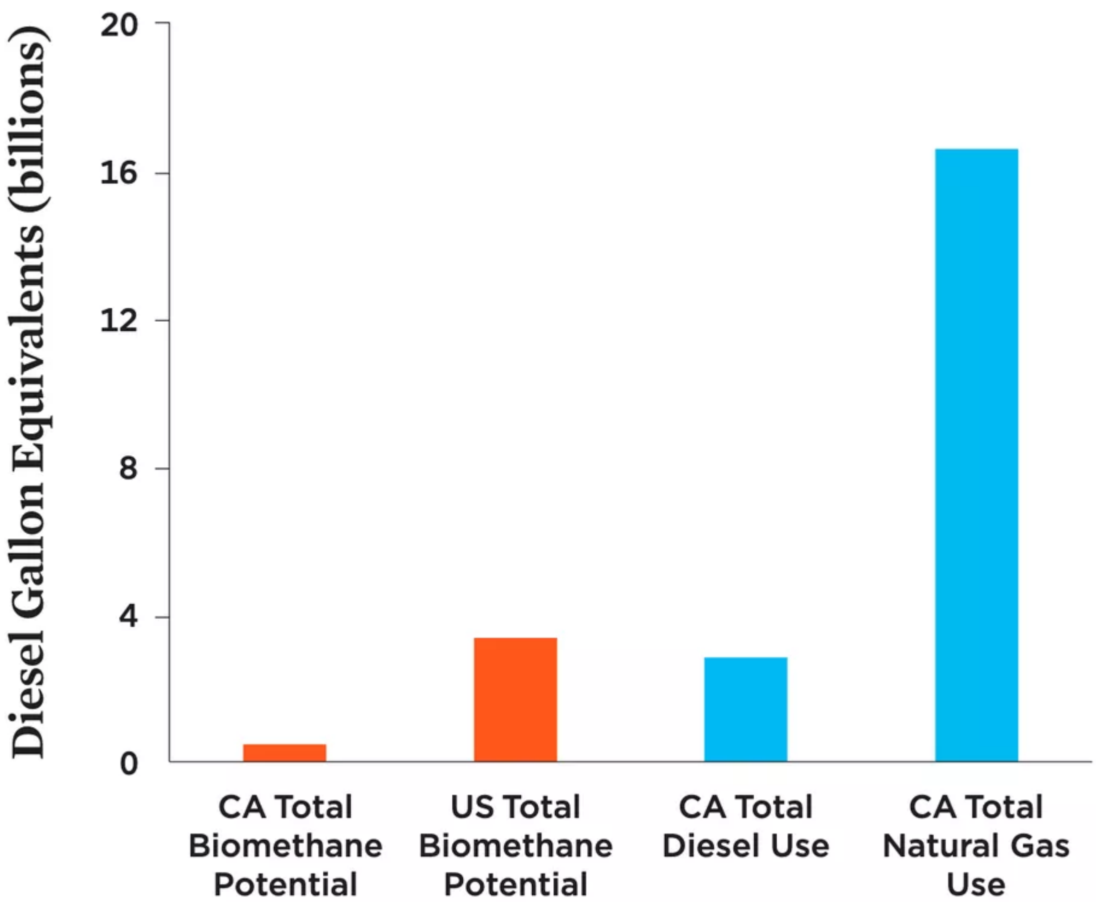
The main question facing RNG is simple: Is there enough of it to decarbonize existing uses of natural gas, like buildings? Several states have looked into this closely. The answer, in a word, is no.

In its **deep decarbonization pathways study**, the CEC concluded that, if California had access to its population-weighted share of total US bioenergy output, "there appears to be insufficient biomethane to displace the necessary amount of building and industry fossil natural gas consumption to meet the state's long-term climate goals."

UC Davis also did **a study** on the potential of RNG in California. It found that, all told, about 82 billion cubic feet a year (bcf/y) of biomethane sources are "attractive for investment," taking into account state and federal incentives. By way of comparison, in 2017, California **consumed** about 2,110 bcf/y of natural gas. So under the most optimistic assumptions, RNG could replace 4.1 percent of California's gas demand (1.6 percent on the low end of estimates).

What about RNG for transportation, another idea that the natural gas industry has long supported? A **2017 report** from the Union of Concerned Scientists showed that it would require almost the entire country's RNG potential to replace diesel fuel alone in California.

FIGURE 1. **Availability of Biomethane from Waste Compared with Diesel and Natural Gas Use in California**



In 2013, the National Renewable Energy Laboratory (NREL) **concluded** that the total potential for biogas in the US (excluding energy crops) is about 431 trillion BTUs. In 2015, California used about 1.6 quadrillion BTUs in its buildings. So if the entire country's biogas potential were devoted to California buildings and nothing else, it would replace about a quarter of the gas used.

Long story short: There literally isn't enough RNG in the US to decarbonize California buildings.

A **Washington State University study** done for the Washington Department of Commerce found something similar for that state: "adequate opportunities exist for RNG production equivalent to 3 percent to 5 percent of current natural gas consumption in Washington."

A **study by the Oregon Department of Energy** found that if the state maximized its domestic resources, it could replace between 10 and 20 percent of its natural gas use with RNG.

Finally, a **more optimistic study by the gas industry itself** found that, if RNG is combined with **synthetic natural gas (SNG) made from electrolyzed hydrogen and captured carbon**, it could replace 6 to 13 percent of the US demand for pipeline gas by 2040.

There is no credible study anywhere claiming that RNG can fully decarbonize the natural gas system, by California's 2045 deadline or ever.

RNG is extremely costly compared to alternatives

Gas utilities are proposing to increase RNG in their pipelines and to charge their customers for the extra expense through rate hikes. SoCalGas has **pledged 20 percent RNG by 2030** (it proposes to raise rates 30 percent between 2018 and 2022).

"As California charts its path toward carbon neutrality some have suggested that electrification is the silver bullet to get us there," SoCalGas's Detz told Vox. "But the science is clear, electrification alone is not a pathway for getting to carbon neutral.

"SoCalGas is committed to becoming the cleanest gas utility in North America," she added.

In the Pacific Northwest, NW Natural, a large gas utility in Oregon, has pledged **30 percent emissions reductions from 2015 levels by 2035** (it proposes to hike rates by $2.50 to $3 a month per customer).

While RNG is a promising development and may be useful in some sectors (see below), there is no justification for blending it in pipelines as a way to decarbonize the building sector. For buildings, electric alternatives are available and cheaper.

An electric heat pump, doing its thing. | Shutterstock

Before demonstrating that, it's worth addressing a **particular study** that gas utilities and their allies **like to cite**. It was done by research consultancy Navigant at the behest of SoCalGas. It selects the highest possible estimates of electrification costs and the lowest possible estimates of RNG costs, ignores pipeline leaks, ignores local health and equity impacts, and ignores the sustainability of RNG feedstocks.

But more importantly, it compares the total GHG reductions of RNG blended in the natural gas supply (which would marginally reduce the emissions of all natural gas uses in all sectors) with reductions through electrification in the building sector alone. That's not an apples-to-apples comparison. The question is not the best way to get a third of the way to zero by 2030, as the study does; it's the best way to get all the way to zero.

As we've seen, while natural gas supply might be partially decarbonized with RNG (say, 15 percent, being maximally generous), there is not enough RNG to get it to net zero, which is the ultimate destination. There's no point going down a pathway that ends in a cul de sac in a few years; there's no time.

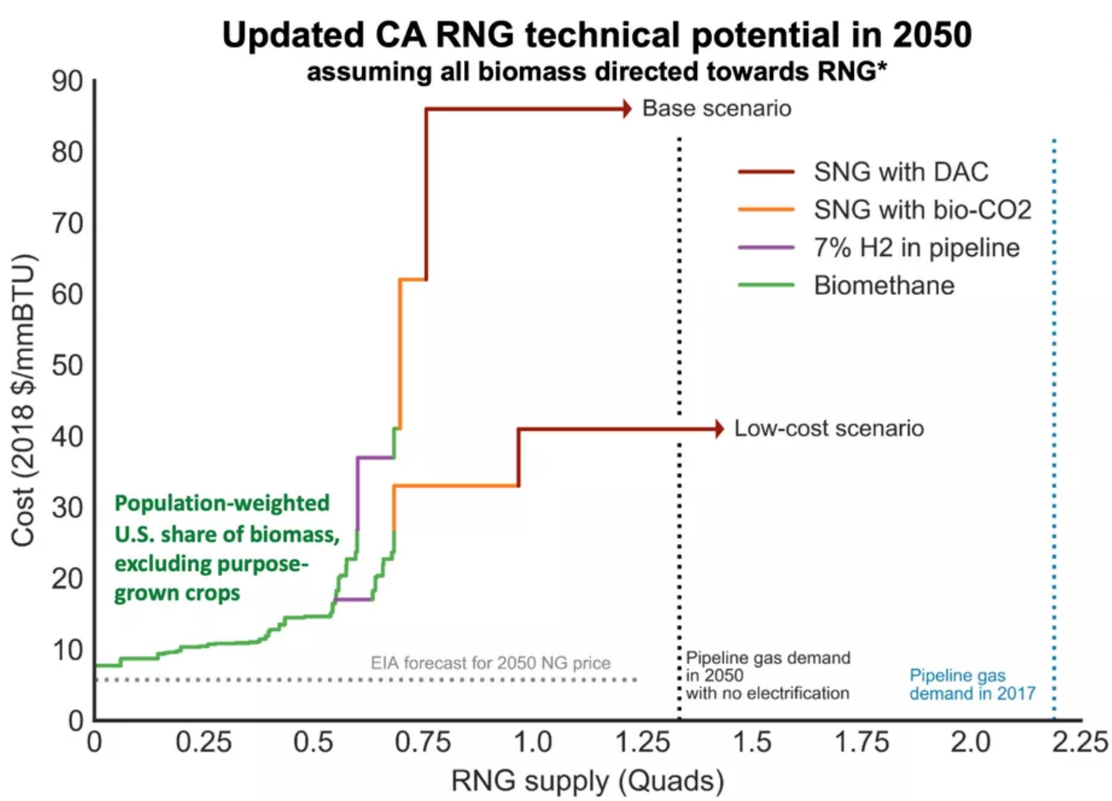
Other, less biased studies look worse for RNG.

A **deep decarbonization study** for California done by Energy & Environmental Economics (E3) found that electrification was the most predictable and cost-effective way to decarbonize buildings, given limits on RNG supply.

In a **2017 report** examining California's program of supportive tariffs for bioenergy (from landfills, ag operations, and forest wastes), the CPUC observed that the cost of the tariffs is "disproportionately high compared with other renewable procurement options" and that there is "no indication of market transformation" that might bring costs down in the future.

"Digesters are steel and cement, and some plastic," says Boccadoro. "Those are not going to come down [in price]; they're going to continue to increase." What's more, the easiest and most suitable sites for biomethane capture are developed first, which means projects become more difficult and expensive as time progresses — the opposite of economies of scale.

Another E3 study on **the future of natural gas distribution** in California found that, even with "aggressive technology learning," the RNG needed to decarbonize the state's natural gas system would be both wildly expensive and insufficient. It would have to be supplemented by heroic amounts of hydrogen and synthetic natural gas from out of state.



E3

If RNG (or SNG) comes from out of state, then it is out of state where the emission reduction occurs. "We keep claiming [RNG] is going to 'decarbonize' the gas system," Boccadoro says, "but it doesn't really decarbonize the gas that's being burned. There's some offset occurring somewhere else, and when that offset occurs outside of California, it doesn't help reduce our emissions here in California."

What's more, shifting to RNG (and SNG) would radically drive up gas costs. No policymaker or regulator in their right mind is going to ask a shrinking group of natural gas ratepayers to pay these exorbitant costs. "I represent some of the largest gas users in the state," Boccadoro says. "We can't afford to pay seven times what our competition is paying for natural gas."

Notably, the study also found that in all scenarios, high and low electrification, total gas "throughput" declined. There is no decarbonization scenario where natural gas use increases.

Another **more recent E3 study** looked at the economics of residential building electrification in California and found that it would represent a savings, not a cost, relative to the status quo. For new construction, an all-electric home saves between $130 and $540 a year relative to one that burns gas. Single-family homes that retrofit from natural gas to all-electric save between $10 and $60 a month on energy bills. And those savings increase over time as electricity gets cheaper and cleaner and natural gas rates continue rising.

A **Synapse Energy study** found that even though electric heat pumps still cost more than natural gas furnaces, for new construction, opting for a heat pump saves $1,500 up front, thanks to the avoided costs of plumbing the property for gas.

The Rocky Mountain Institute did a report on **the economics of all-electric, zero-net-energy homes**, which are already far more favorable than widely understood. In San Francisco, such homes pay their extra upfront costs back within eight years.

To summarize: decarbonizing buildings with electrification saves homeowners and developers money, with savings rising over time; decarbonizing buildings with RNG costs ratepayers money, with costs rising over time.

And that's just costs. There are other impacts of RNG to consider.

RNG exacerbates air pollution problems

Once it is captured from organic sources and injected into pipelines, RNG is chemically identical to natural gas. Methane is methane. It has all the same effects when leaked or combusted.

Methane is a potent greenhouse gas — **28 to 36 times more potent than CO2** over 100 years — and represents 9 percent of California's total GHG emissions. It is also a local air pollutant.

Among other things, it pollutes indoor air when used for cooking. A 2017 **CARB study** found that "**cooking emissions**, especially from gas stoves, have been associated with increased respiratory disease." A **raft of peer-reviewed research** (see **here** and **here**) shows that cooking with gas elevates risk for those in the home, especially for vulnerable populations like **children**. As many as **12 million Californians** are exposed.

Dr. Shelly Miller, PhD
@ShellyMBoulder

Respiratory symptoms were more common in children exposed to a gas stove. "Respiratory Symptoms in Children and Indoor Exposure to Nitrogen Dioxide and Gas Stoves" | American Journal of Respiratory and Critical Care Medicine atsjournals.org/doi/abs/10.116...

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The natural gas industry has pushed for RNG to be used in heavy trucks in place of diesel, but a **2012 study** found that, if the leakage rate in natural gas pipelines is any greater than 1.4 percent, the climate benefits of switching from diesel to RNG are negated. A recent **literature review** found that the leakage rate in California is somewhere between 2.4 and 4.3 percent.

Even if there were no leakage, the combustion of methane in a vehicle emits carbon dioxide, carbon monoxide, and nitrogen oxides.

RNG is also produced by sources that are themselves big polluters. Despite what the rosy term "renewable" might suggest, the CEC **found** that the state's two biggest sources of biogas are landfills and manure from factory farms.

It's better to capture some of the gas from landfills and factory farms than to let it escape into the atmosphere. (Boccadoro says manure methane emissions in California have declined by 25 percent in the last four years.) But it's odd to think of those polluting sources as "renewable." Many people hope they will decline over time, as Americans generate less food waste and eat a healthier diet with less red meat and dairy.

Small farms, with pasture-grazed cows, **generate no appreciable methane**. It's the big, industrial dairy farms that are responsible for 55 percent of the state's methane emissions. As the California Department of Food and Agriculture (CDFA) has handed out subsidies for biodigesters, the **average herd size** of a recipient is 7,430 head. By way of comparison, average herd size in Wisconsin, the second-largest dairy state, is **134 head**. These are huge operations. And they must be, to justify capturing methane; a **2018 study** found that 3,000 head is the minimum herd size needed to make anaerobic digestion economic.

Anaerobic digesters also leak methane, at a rate of **between 2 and 3 percent**, adding to their lifecycle GHGs in a way that is rarely captured in models.

For now at least, to the extent that decarbonization is linked to RNG, it is reliant on a steady supply of landfills and factory farms, which produce the very sort of pollution that electrification eliminates. A **study** last year in *Environmental Science & Technology* summed up the difference for California:

> Compared with business-as-usual levels, a decarbonization pathway that focuses on electrification and clean renewable energy is estimated to reduce concentrations of fine particulate matter (PM2.5) by 18–37% in major metropolitan areas of California and subsequently avoid about 12,100 (9,600–14,600) premature deaths. In contrast, only a quarter of such health cobenefits, i.e., 2,800 (2,300–3,400) avoided deaths, can be achieved through a pathway focusing more on combustible renewable fuels.

The sun and wind are healthier sources of energy than trash and shit.

Renewable ... ish. | Wikimedia

RNG impacts are concentrated in vulnerable communities

The industrial dairy farms that produce RNG are mostly located in the San Joaquin Valley, one of the poorest areas of the state, where African Americans, Latinos, and Native Americans make up the **majority of the population**. It is home to the **nation's worst air pollution**, the highest rate of asthma in children, and **nitrate-laced drinking water**.

Livestock operations are the **top source of ozone-causing pollutants** in the area, a major source of nitrate pollution, and a **major source of ammonia emissions**, which cause eutrophication of surface water and fine particulate pollution. They also release **persistent odors that cause headaches**.

Residents of the area have been **pushing the state government** to stop subsidizing harmful agriculture and livestock management and start subsidizing regenerative and other climate-friendly agricultural practices. But the state still devotes a far smaller amount to those practices than to dairy digesters — **$21.6 million versus $72.4 million**.

California's pioneering law **SB 1383** requires that the state reduce methane pollution from organic waste 40 percent by 2030; it does not require that it capture 40 percent of methane. It can just as easily, often less expensively, reduce the waste streams that produce the methane. But if RNG is made into a valuable commodity, it will bias the industry (and the lawmakers it lobbies) to seek expanded dairy operations.

Residents of the San Joaquin Valley reasonably worry that a major new source of revenue for industrial dairy farms will **help support an otherwise economically marginal industry**, perhaps even encourage its growth, and that their children will pay the hidden costs.

RNG is worth pursuing, but not as an alternative to electrification

None of the above should be taken as arguing against RNG, provided that protections for vulnerable communities are built in. As long as there are landfills, giant manure ponds, agriculture and forestry waste, and sewage treatment plants off-gassing methane into the atmosphere, it makes sense to capture as much of that methane as possible and use it. It's better than fracking it out of the ground.

And there are plenty of good ways to put RNG to use.

I've mostly focused on California in this post, but it's worth pointing out that in other, less temperate states, the electricity system faces higher seasonal peaks, as everyone turns on heaters or air conditioners at once. Adding both cars and all remaining buildings to already congested grids could threaten their reliability. Many states, like the densely populated states of the Northeast US, will need much longer than California to prepare, to build their grids out and learn how to manage all that new electricity demand. Until then, RNG could work in the background to lower the carbon intensity of natural gas.

And it may be that there are some sectors of the economy that resist electrification and still need combustible liquid fuels even through 2050 — so-called "**harder-to-abate**" sectors like shipping, aviation, or **heavy industry**. It's better for those sectors to burn RNG (and SNG) than to burn fracked gas.

There are also lots of vehicles already in circulation that could benefit from RNG. Recently, UPS **bought a bunch of RNG** to reduce the climate impact of its existing fleet of natural-gas trucks. But even UPS is realistic:

> **Gavin Bade**
> @GavinBade
>
> Replying to @GavinBade
>
> TIL: UPS has 6800 natural gas-powered vehicles, and SVP Jim

Bruce says soon they'll all be renewable nat gas.

"But there's only so much renewable natural gas out there," he says. "We know how to deploy at scale, when the [electric] trucks are ready."

2:38 PM · Sep 24, 2019

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Liquid fuels will probably be needed for various subsectors and niche applications for a long while, so it's worth pursuing every promising carbon-neutral or carbon-negative fuel.

But there are two key points to emphasize here. First, there is no scenario in which RNG is an alternative to electrification. At best, it is a complement. Electrification should move full speed ahead no matter what happens with RNG.

Second, California buildings are not one of those harder-to-abate sectors that need liquid fuels. A **study last year** in the journal *Atmosphere* specifically compared various pathways to decarbonizing space and water heating in California buildings, including "solar thermal, biogas, synthetic natural gas, and electrification." It found that electrification is the only alternative that can serve all heating loads in the state (others cover between 2 and 70 percent). What's more, it is the least cost pathway, coming in at 25 to 90+ percent cheaper than the alternatives.

The study concludes: "[E]nergy efficiency with electrification of heating is the most likely path to achieve the large carbon emission reduction needed from this sector."

RNG cannot delay the inevitable decline of natural gas

Make no mistake, the natural gas industry **opposes electrification** because it wants to expand pipeline infrastructure. At an American Gas Association **meeting** in 2018, one industry leader, discussing RNG, tasked the audience to "consider how technologies to decarbonize the pipeline can serve as a conduit to environmental organizations, thereby seeking to mitigate the opposition's fervor against infrastructure expansion."

But the development of RNG, while worth pursuing, does not mean what SoCalGas and other natural gas utilities want it to mean. It is no reason to expand gas infrastructure; the fervor is as warranted as ever.

A recent **report from E3G** examined the role of natural gas in the EU's decarbonized future. It found that in all its scenarios, even the most generous to decarbonized gas, the total amount of natural gas "throughput" in the system declined. It concluded that RNG should be pursued, but because it is so expensive, it should be targeted at harder-to-abate sectors where it has the highest social value. Above all, "the future prospect of renewable and decarbonised gases is no reason to slow down electrification or efficiency at this stage."

The same is true in the US, as virtually every study agrees. Deep decarbonization means the decline of the natural gas industry, no matter what happens with RNG or SNG.

As the CEC has **concluded**, allowing the decline of natural gas to unfold organically threatens to be an unnecessarily long and messy process, leaving the growing costs of maintaining natural gas infrastructure piled on the shoulders of a shrinking group of ratepayers, largely those who can't afford to escape the system. The only responsible course of action at this point is the one the CPUC **appears to be taking**: planning for a deliberate phaseout of natural gas, with costs shared equitably.

RNG is an interesting development at the margins, for some energy applications. But it is no bigger than a blip in the larger story of natural gas, which is one of inexorable and inevitable fading away to the margins.