Before the Ontario Energy Board

EB-2022-0200

Enbridge Gas 2024 Rebasing

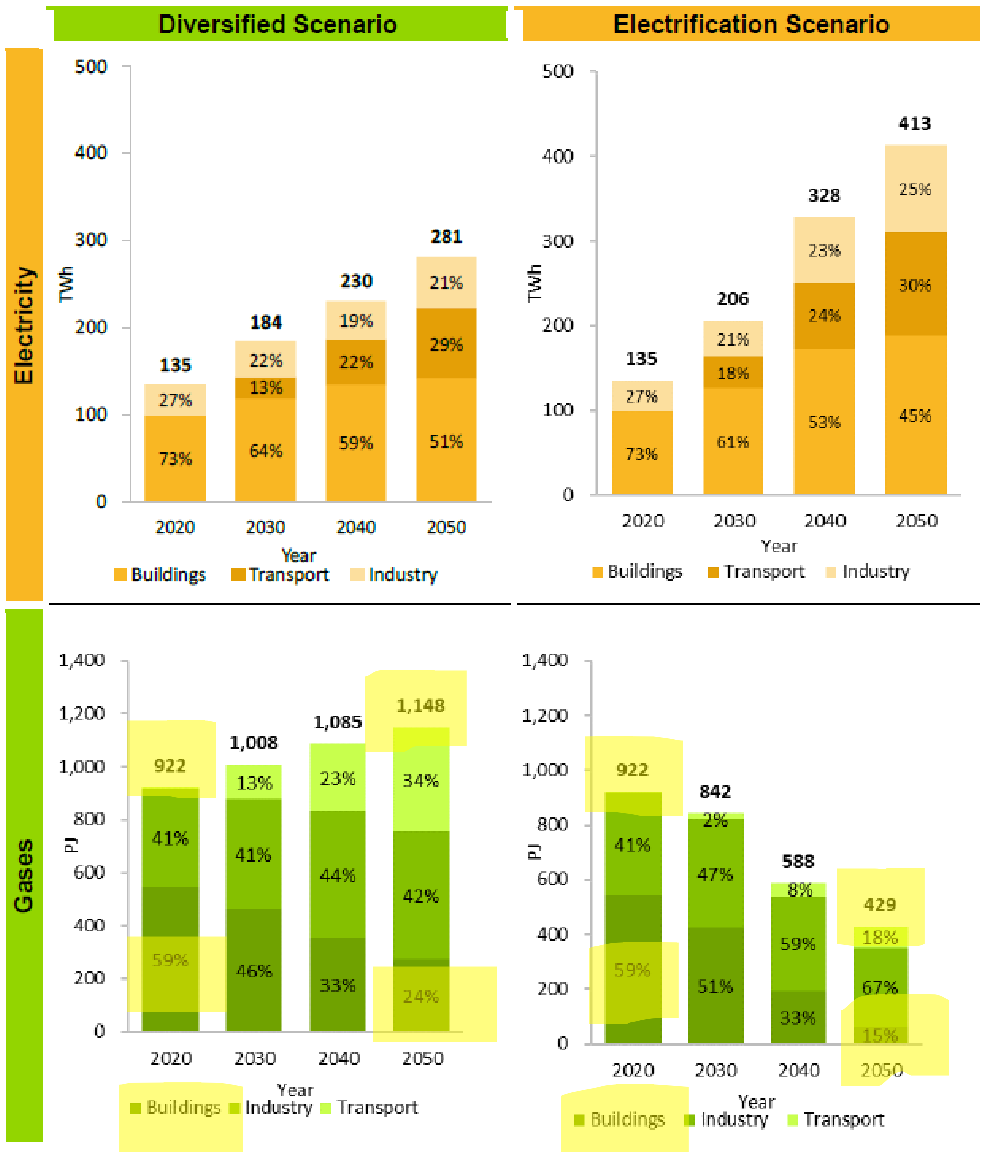
GEC CROSS COMPENDIUM

Filed: July 11, 2023

David Poch

Counsel for GEC

Figure 8. Comparison of Annual Demand Scenario Forecasts by Sector /u



Buildings sector drop in annual demand (based on Guidehouse Fig. 8 (above)

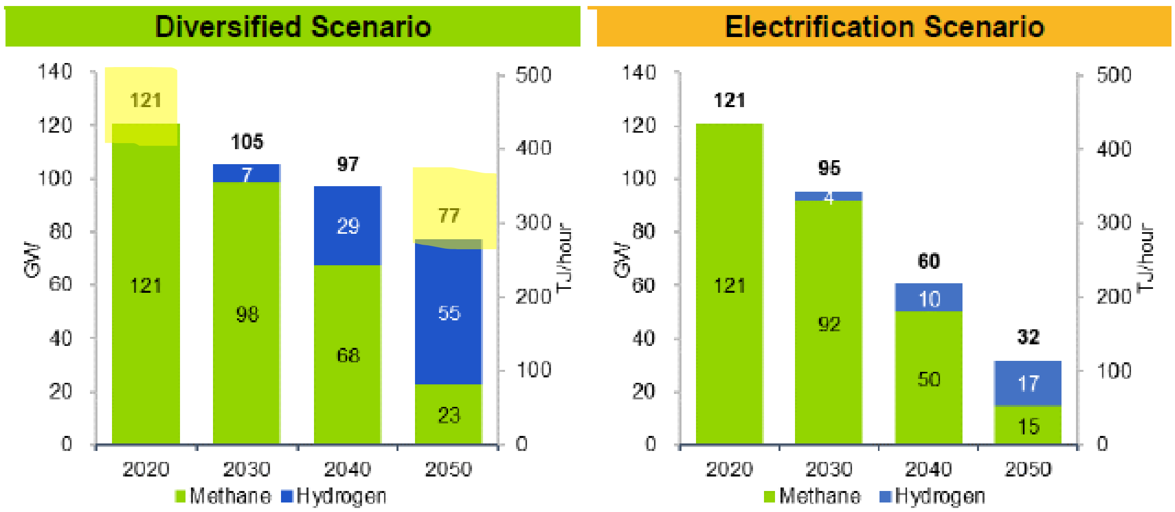
Diversified
2020: 59% X 922 = 543
2050: 24% X 1148 = 256
(543-256)/543 = 53% drop
Share drops by 59% from 59% to 24%

Electrification
2020: 59% X 922 = 543
2050: 15% X 429 = 64
(543-64)/543 = 88% drop
Share drops by 75% from 59% to 15%

Guidehouse Pathways to Net Zero Emissions for Ontario

Figure 10. Gas System Peak Demand[59]

/u



System Peak Demand

Diversified2020 to 2050:

(121-77)/121 = 36% drop

Electrification2020 to 2050:

(121-32)/121 = 74% drop

Excerpt from Exhibit I.1.10-GEC-15, Page 5 of 6:

Table 2
Peak Gas (Methane + Hydrogen) Demand for the Buildings Sector (TJ/hour)

Scenario	2020	2030	2040	2050	
Electrification	289	226	102	33	/u
Diversified	289	246	190	146	/u

Table 3
Peak Gas (Methane + Hydrogen) Demand for the Buildings Sector (GW)

Scenario	2020	2030	2040	2050	
Electrification	80	63	28	9	/u
Diversified	80	68	53	40	/u

GEC Calculations:

Buildings sector peak demand drop 2020 to 2050:

Electrification: (80-9)/80 = 89%

Diversified: (80-40)/80 = 50%

Non- buildings (Ind. + Transport) 2020: 121* – 80 = 41 GW

Electrification 2050: 32* – 9 = 23 GW (44% drop)

Diversified 2050: 77* – 40 = 37 GW (10% drop)

*System peak from fig. 10

Answer to Undertaking from
Green Energy Coalition (GEC)

Undertaking

Tr: 39

To provide a breakout of gas peak demand by content -- by energy content and by volume broken out by fuel for each sector.

Response:

The following response was provided by Guidehouse Canada Ltd.:

The following tables include a breakout of gas peak demand by sector, by energy content, Table 1, and by volume, Table 2.

Table 1
Contribution to Coincident Peak Demand,
by Scenario and Decade (GW)

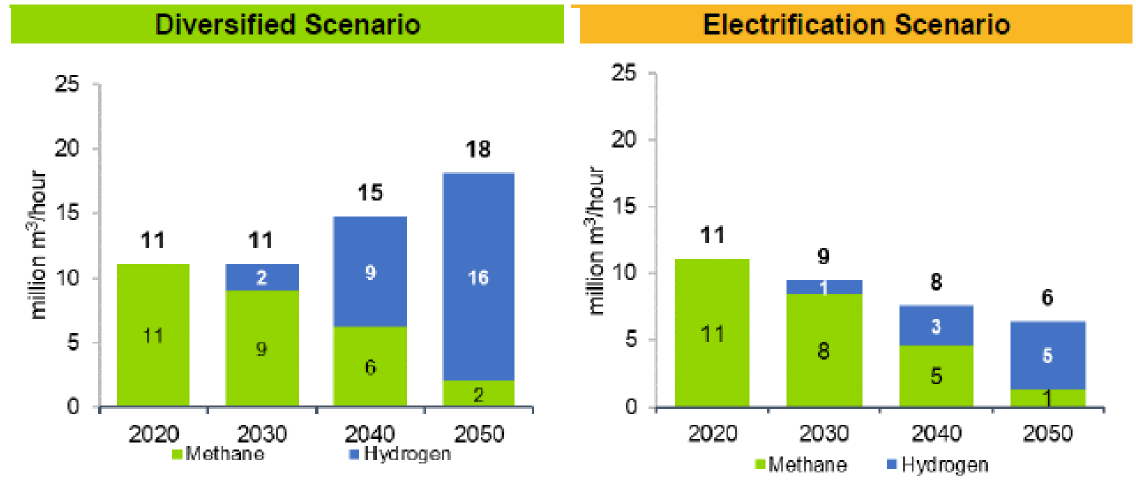
Fuel Type	Sector	**2020**	**2030**	**2040**	**2050**
Diversified Scenario					
Hydrogen	Buildings	0.0	0.5	11.3	20.7
	Industry	0.0	3.5	11.1	23.3
	Transportation	0.0	3.0	6.6	10.7
Methane	Buildings	71.3	56.2	28.9	4.8
	Industry	49.1	40.7	37.0	16.1
	Transportation	0.6	1.5	1.9	1.8
Electrification Scenario					
Hydrogen	Buildings	0.0	0.0	1.4	3.5
	Industry	0.0	2.8	7.3	11.2
	Transportation	0.0	0.7	1.5	2.5
Methane	Buildings	71.3	52.3	21.8	2.4
	Industry	49.1	39.5	28.4	12.3
	Transportation	0.6	0.0	0.0	0.0

GEC ADDED CALCULATIONS:
Buildings (Diversified) 2020: 71.3, 2050: 25.5 --- 64% drop
I & T (Diversified) 2020: 49.7, 2050: 51.9 --- 2.2% rise
I (Diversified) 2020: 49.1, 2050: 39.4 --- 20% drop

Buildings (Elec. Scen.) 2020: 71.3, 2050: 5.9 --- 92% drop
I & T (Elec. Scen.) 2020: 49.7, 2050: 26 --- 48% drop
I (Elec. Scen.) 2020: 49.1, 2050: 23.5 --- 52% drop

Figure 11. Volumetric Gas System Peak Demand[59]

/u



GEC Calculations: Changed Peak Volume 2020 – 2050

Diversified: (18 – 11)/11 = 64% increase

But a 36% drop in peak GW (Fig. 10)

Electrification: (11-6)/11 = 45% drop

With a 74% drop in peak GW (Fig. 10)

Table 2
Contribution to Coincident Peak Demand,
by Scenario and Decade (Mm3/hour)

Fuel Type	Sector	**2020**	**2030**	**2040**	**2050**
Diversified Scenario					
Hydrogen	Buildings	0.0	0.2	3.3	6.1
	Industry	0.0	1.0	3.3	6.8
	Transportation	0.0	0.9	2.0	3.2
Methane	Buildings	6.5	5.2	2.7	0.4
	Industry	4.5	3.7	3.4	1.5
	Transportation	0.1	0.1	0.2	0.2
Electrification Scenario					
Hydrogen	Buildings	0.0	0.0	0.4	1.0
	Industry	0.0	0.8	2.1	3.3
	Transportation	0.0	0.2	0.4	0.7
Methane	Buildings	6.5	4.8	2.0	0.2
	Industry	4.5	3.6	2.6	1.1
	Transportation	0.1	0.0	0.0	0.0

GEC ADDED CALCULATIONS:
Buildings (Diversified) 2020: 6.5, 2050: 6.5 --- 0% change
I & T (Diversified) 2020: 4.6, 2050: 11.7 --- 154% rise
I (Diversified) 2020: 4.5, 2050: 8.3 --- 84% rise

Buildings (Elec. Scen.) 2020: 6.5, 2050: 2.4 --- 63% drop
I & T (Elec. Scen.) 2020: 4.6, 2050: 5.1 --- 11% rise
I (Elec. Scen.) 2020: 4.5, 2050: 4.4 --- 2% drop

The methane peak demand presented in the tables above is adjusted from the peak demand used in the Guidehouse model to reflect ETSA inputs, such that peak methane demand in 2020 is 121 GW. As noted in footnote 59 of the updated P2NZ Report, this calibration does not affect the model's optimization or the cost results that it produces because the model calculates costs associated with the existing methane system based on energy content, not capacity, and because no new methane infrastructure capacity is built in any scenario considered in this analysis.

heating equipment. As a result, we have made assumptions on how those fuel shares break down into individual heating equipment in our analysis. For example, in 2050, the Diversified scenario assumes that 55% of households have gas heating provided by gas heat pumps, an extrapolation of the Enbridge Gas scenario. To comply with the Pan-Canadian Framework, gas-equipped buildings are assumed to shift to gas-powered heat pumps post-2035. In addition, 40% of household heating is electric heating, which is assumed to be a mix of air-source and geothermal heat pumps. In 2050, the Electrification scenario assumes that 85% of households have electric heating, an extrapolation of the Enbridge Gas scenario. The 85% is assumed to be 75% air-source heat pumps and 10% geothermal heat pumps. Geothermal heat pumps are assumed to be primarily installed in new builds to bring down costs and so they are applicable to a large share of homes. The 10% of household heating powered by RNG is entirely gas heat pumps. The share of household heating technologies are given in Table B-1 and Table B-2 for the Diversified and Electrification scenarios, respectively.

Table B-1. Share of Households per Space Heating Technology Type – Diversified Scenario /u

Space Heating	2020	2030	2040	2050
Gas Heat Pump	0%	6%	34%	55%
Air-Source Heat Pump	7%	13%	24%	30%
Geothermal Heat Pump	0%	4%	7%	10%
Natural Gas Furnace	82%	68%	28%	0%
Other	11%	10%	7%	5%

Table B-2. Share of Households per Space Heating Technology Type – Electrification Scenario /u

Space Heating	2020	2030	2040	2050
Gas Heat Pump	0%	4%	6%	10%
Air-Source Heat Pump	7%	14%	52%	75%
Geothermal Heat Pump	0%	4%	7%	10%
Natural Gas Furnace	82%	68%	27%	0%
Other	11%	10%	8%	5%

- **Water heating:** Most Ontario homes rely on natural gas for hot water. Increased fuel switching to electric water heaters, both instant and storage-based, drive the GHG emissions reductions for this end use. The Electrification scenario assumes that by 2050, all Ontario homes will rely on electricity for hot water. The Diversified scenario assumes that just over half of homes will still rely on gas via hydrogen or RNG. This is consistent with space heating since a high penetration of integrated space and water heating systems is assumed.
- **Cooking:** One in four Ontario homes rely on gas cooking appliances today. This stock slowly and steadily declines over time based on the Enbridge Gas forecasts. By 2050, one in five homes will still rely on gas cooking appliances in the Diversified scenario while one in 10 will in the Electrification scenario.
- **Washing/drying appliances:** This end use is predominately electric. The Diversified scenario assumes that approximately half of homes with gas laundry appliances will switch to electric appliances by 2050. The Electrification scenario assumes that more than half of homes with gas laundry appliances will switch to electric appliances by 2050. Both scenarios assume new builds with gas washing and drying appliances are negligible.

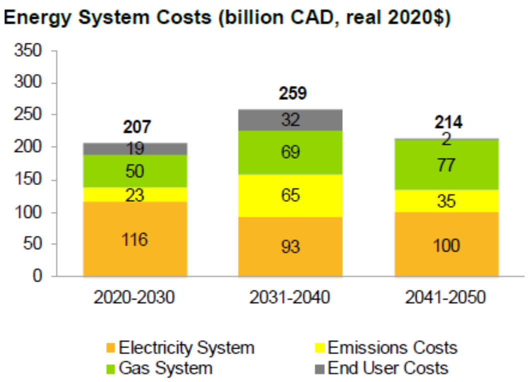
B.2.2 Transport

The Pathways scenarios account for areas of transport not covered by the Enbridge Gas scenarios. Incorporating these areas is critical because this ensures the Diversified and Electrification scenarios are net zero by 2050. The Enbridge Gas scenarios adopted a forecast by the Canada Energy

In the discussion of sensitivity analyses in section 5.6, emissions costs are allocated to the gas system. Figure 18 reports emissions costs separate from gas system costs to better demonstrate the costs associated with investment in the gas system.

Figure 18. Energy System Costs for Diversified and Electrification Scenarios[90] /u

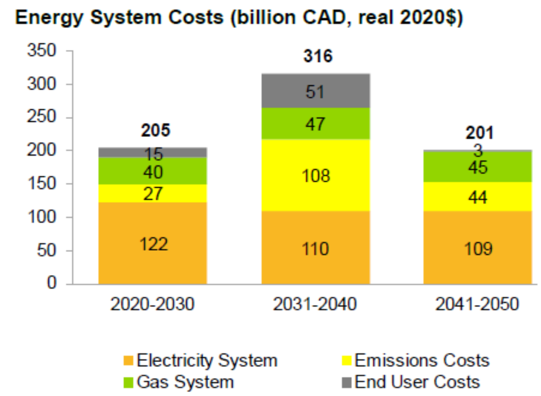
Diversified



Billion CAD, real 2020$

	2020-30	2031-40	2041-50	Total
Gas System	50	69	77	**197**
Elec. System	116	93	100	**309**
Emissions	23	65	35	122
End Users	19	32	2	**53**
Total	**207**	**259**	**214**	**681**

Electrification



Billion CAD, real 2020$

	2020-30	2031-40	2041-50	Total
Gas System	40	47	45	**132**
Elec. System	122	110	109	**341**
Emissions	27	108	44	179
End Users	15	51	3	**70**
Total	**205**	**316**	**201**	**722**

Posterity about the changes that happened in the Pathways study in -- this document is in relation the ETI scenario, which is filed, I believe, as an attachment number 1 in Exhibit 1, tab 10, schedule 6, and we did speak to them about the changes just to make sure that it wouldn't impact that work, and they felt comfortable as well. I can't speak for them, but my takeaway from the conversation was we don't believe there would be any changes in the BTR work.

MR. RUBENSTEIN: And I just want to confirm both the original study as well as the updated study do not take into account either what would have been 2022 announced and obviously budgeted -- the budgeted 2023 announced federal tax incentives regarding hydrogen, clean electricity investment, clean tech investment, CCUS investment tax credits, correct?

MS. ROSZELL: That's correct. That wasn't released at the time that we completed the study.

MS. MURPHY: With respect to the ETSA work, study was finalized in June of 2022, but the modelling was done a little bit ahead of that, so anything subsequent to that would not have been contemplated.

MR. RUBENSTEIN: And you haven't determined informally or -- well, I don't want to say informally, but you haven't thought about what the implications of some of those tax credits would be on the outcome of, the outputs of the model, if you --

MS. MURPHY: Speaking from an Enbridge perspective and then if Guidehouse wants to add on to that, I mean, this -- the date of filing of the evidence for the rebasing application necessitated that we start this work well in advance, and so it represents that point in time, and we haven't undertaken to redo the model based on those changes, and even with the more current updates that Guidehouse has done, I would say it's still representative of the point in time when we originally did this work.

MR. RUBENSTEIN: Sorry, I wasn't asking why didn't you include this information. I recognize the timing and the details and all that.

I was just asking: Does either Enbridge or Guidehouse have a view -- and maybe at a high level -- of what type of impacts we would have -- we could have -- we -- if the study was being redone today or now based on the information we have know, how it may or may not impact the results?

MS. ROSZELL: I don't believe it would impact the results, because we're not modelling policy-based -- many policy-based levers, right? We are modelling total cost, so the adoption or the amount of hydrogen or solar, for example, may be impacted by the ITCs, and we are using two different scenarios to model what that may look like and not basing that on the existing policies either, right? They are just potential outcomes.

We haven't modelled what the outcome is going to be of ITCs. It is just within a realm of possibility depending on what the policy ends up being.

MR. RUBENSTEIN: But they do impact the price. They impact the price -- the inputs, which --

MS. ROSZELL: Yes.

MR. RUBENSTEIN: -- because the prices would change with those impacts.

MS. ROSZELL: Yep.

MR. RINGO: Right. And we've been through similar exercises south of the border in our studies in the U.S., looking at how the Inflation Reduction Act and all of its incentives for energy technologies could impact the future, and it's difficult to say which, you know, if you are looking for a directional impact, which scenario would be advantaged more by an announced incentives.

It is really hard to say, because many of the -- you know, there's a lot of technologies that are common to both scenarios. Both scenarios really turn up the dial on wind and solar and storage and other things that are -- could receive incentives in the future, so it would have an impact, I agree. It would probably drive costs down for both scenarios if you assume that government incentives reduce the price instead of just redistributing the price.

But we haven't done an in-depth assessment of that.

MR. RUBENSTEIN: I hope they reduce their price.

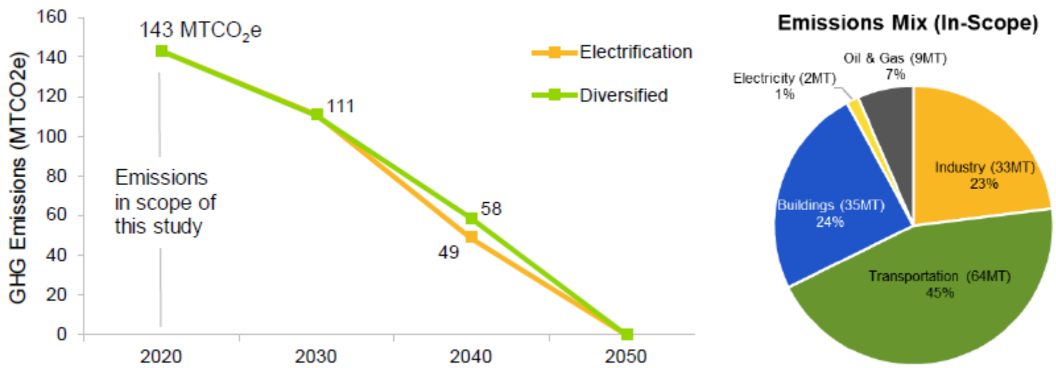
Okay. Well, thank you very much for --

MR. RINGO: Well, somebody is going to be paying for them, right, but that's a different debate for a different day, right?

MR. RUBENSTEIN: Thank you very much.

/u

Figure 19. Ontario Emissions Pathways[95]



Source: Updated: 2023-04-21, EB-2022-0200, Exhibit 1, Tab 10, Schedule 5, Attachment 2, Page 48 of 88

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, Pages 45 and 46 of 86

Question(s):

Guidehouse attributes some of the higher costs of the electrification scenario to the timing of carbon emissions (where emissions occur later when carbon pricing has escalated). It finds emissions costs of $120 billion for the diversified scenario vs $191B for electrification ($71 billion of the $181 billion difference).

a) Please reconcile the above with the graphics at Guidehouse figure 19 and at Posterity Ex. 1, T 10, S 6, Att 1 p. 25 of 34 (ETI Exhibit 17) both of which appear to depict equal or lower emissions for the electrification scenario at all times.

b) Does Guidehouse agree that carbon taxes affect rates but are not a net societal cost (as opposed to emissions)?

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) The question compares the emissions level and emissions costs for the Diversified and Electrification scenarios. The question observes that in 2040, the Electrification scenario has a lower level of emissions but a higher cost of emissions. This is owing to the different emissions cost trajectories that the analysis assumed for the two scenarios. Table A-2 of the *Pathways to Net Zero Emissions for Ontario* Study presents the carbon price forecast for the Diversified and Electrification scenarios. These carbon price projections are aligned with the assumptions of the ETSA study, which assumed that higher carbon prices would be implemented in an Electrification scenario to incentivize energy consumers to electrify their consumption.

b) This *Pathways to Net Zero Emissions for Ontario* study did not examine how various cost components would be socialized among ratepayers, so Guidehouse cannot comment on how carbon prices would impact energy rates in the scenarios considered here. This analysis treated carbon taxes as a material cost that represents the impact of GHG emissions.

Guidehouse ENBRIDGE

Decarbonization Pathways Study

Scenario Development Methodology

September 2021

Filed: 2023-04-06, EB-2022-0200, Exhibit JT1.26, Attachment 11, Pa

Scenario Narratives

The Diversified and Electric scenarios are intended to represent plausible, but differen visions of the Ontario energy system by 2050. They are not perfect or optimal scenari

Diversified Scenario

Decarbonizing the gas grid with renewable and low carbon gas are used in a smart combination with renewable electricity

BUILDINGS

Gas continues to play a key role in buildings

- Gas heat pumps and other gas heating technologies playing a dominate role and are complimented by moderate electrification of heating
- Energy efficiency retrofits and new building codes will reduce energy demand

INDUSTRY

Hydrogen and Gas with CCS play a key role in industry

- Industrial segments start converting in 2030 and convert at equipment turnover rate
- CCS used in industrial sectors not using H2
- Electrification plays a limited role decarbonization of industry

TRANSPORT

Gas plays significant role in heavy road transport

- Light duty road transport is largely electrified with a limited role of gas.
- In the short term, CNG plays a role in heavy duty road transport. In the long-term, H2, bio-CNG and biodiesel dominate with electricity playing a limited role.

POWER

Gas provides dispatchable power and bulk storage

- In both scenarios' electricity is supplied by hydro, biomass, wind, solar, and nuclear energy
- Gas power plants and gas storage available for balancing
- Natural gas with CCS provide power in the short term with renewable gas and hydrogen playing a role in the long-term. Renewable gas and H2 can be produced domestically and imported.

Electric Scenario

Electrification is the main form of decarbonization with gas use limited to where no reasonable alternative exists

BUILDINGS

Electricity dominates building energy consumption with very limited gas consumption

- Mandated electrification of space & water heating for residential and commercial new and existing buildings
- Energy efficiency retrofits and new building codes will reduce energy demand

INDUSTRY

Electrification plays a dominate role in the decarbonization of industry

- Where electrification is infeasible hydrogen and gas with CCS supplement the decarbonization
- Electrification of HVAC end-uses

TRANSPORT

Gas limited to heavy duty road transport

- Light duty road transport is fully electrified
- Electricity also dominates heavy duty but with some role for CNG in the short term and H2, bio-CNG and biodiesel in the long-term

POWER

Gas does not play a role in providing dispatchable power

- In both scenarios' electricity is supplied by hydro, biomass, wind, solar, and nuclear energy
- Gas use in electricity generation is modelled endogenously. In other words, the cost-optimisation dispatch engine of our model will determine whether methane or hydrogen OCGTs will be needed to balance electricity supply and demand on an hour-to-hour basis.

Guidehouse

ENBRIDGE GAS INC.

Answer to Undertaking from
Green Energy Coalition (GEC)

Undertaking

Tr: 20

To review and provide comment on Exhibit KT9.1.

Response:

The following response was provided by Guidehouse Canada Ltd.:

As provided previously in response at Exhibit I.1.10-ED-60, Table 1 includes a breakout of emissions by decade and total emissions costs per decade for the Electrification scenario using the carbon pricing assumptions for the Electrification scenario in the updated P2NZ Report (April 2023).

Table 2 applies the carbon price assumptions from the Diversified scenario to the emissions projections from the Electrification scenario. Guidehouse notes that the values in Table 2 are the result of a calculation to assist intervenors in applying the Diversified scenario carbon prices to the Electrification scenario results. The values in Table 2 were not derived using the dispatch optimization model and, as such, the values in Table 2 do not represent the least cost pathway that the model would determine for the Electrification scenario if the Electrification scenario were modeled with the carbon prices in Table 2.

Table 1
Electrification Scenario, Emissions by Source and Emissions Cost per Decade using Electrification Scenario Carbon Pricing

	2020	2030	2040	2050	
Carbon Emissions by Source (million tCO2e / year)					
Renewable natural gas	0.00	0.00	0.02	0.02	
Biomass with CCS	0.00	0.00	-2.40	-4.81	
Natural gas with CCS	0.00	0.00	0.36	0.57	
Natural gas imports	51.25	49.28	19.19	0.00	
H2 from natural gas + CCS	0.00	0.33	0.86	0.86	
Carbon cost per ton ($/tCO2e)	$27.50	$230.95	$235.92	$235.92	
Time Period		2020-2030	2031-2040	2041-2050	Total
Total Emissions Cost (Real 2020$)		$27 B	$108 B	$44 B	$179 B

Table 2
Electrification Scenario, Emissions Cost per Decade using Diversified Scenario Carbon Pricing

	2020	2030	2040	2050	
Carbon cost per ton ($/tCO2e)	$27.50	$136.38	$138.78	$138.78	
Time Period		2020-2030	2031-2040	2041-2050	Total
Total Emissions Cost (Real 2020$)		$22 B	$63 B	$26 B	$112 B

Shaded portions added

ENBRIDGE GAS INC.

Answer to Undertaking from
Green Energy Coalition (GEC)

Undertaking

Tr: 39

To provide a breakout of gas peak demand by content -- by energy content and by volume broken out by fuel for each sector.

Response:

The following response was provided by Guidehouse Canada Ltd.:

The following tables include a breakout of gas peak demand by sector, by energy content, Table 1, and by volume, Table 2.

Table 1
Contribution to Coincident Peak Demand,
by Scenario and Decade (GW)

Fuel Type	Sector	**2020**	**2030**	**2040**	**2050**	**2050 % of Bldgs.**
Diversified Scenario						
Hydrogen	Buildings	0.0	0.5	11.3	20.7	81%
	Industry	0.0	3.5	11.1	23.3	
	Transportation	0.0	3.0	6.6	10.7	
Methane	Buildings	71.3	56.2	28.9	4.8	19%
	Industry	49.1	40.7	37.0	16.1	
	Transportation	0.6	1.5	1.9	1.8	
Electrification Scenario						
Hydrogen	Buildings	0.0	0.0	1.4	3.5	
	Industry	0.0	2.8	7.3	11.2	
	Transportation	0.0	0.7	1.5	2.5	
Methane	Buildings	71.3	52.3	21.8	2.4	
	Industry	49.1	39.5	28.4	12.3	
	Transportation	0.6	0.0	0.0	0.0	

Table 2
Contribution to Coincident Peak Demand,
by Scenario and Decade (Mm3/hour)

Fuel Type	Sector	**2020**	**2030**	**2040**	**2050**	**2050 Bldgs. %**
Diversified Scenario						
Hydrogen	Buildings	0.0	0.2	3.3	6.1	94%
	Industry	0.0	1.0	3.3	6.8	
	Transportation	0.0	0.9	2.0	3.2	
Methane	Buildings	6.5	5.2	2.7	0.4	6%
	Industry	4.5	3.7	3.4	1.5	
	Transportation	0.1	0.1	0.2	0.2	
Electrification Scenario						
Hydrogen	Buildings	0.0	0.0	0.4	1.0	
	Industry	0.0	0.8	2.1	3.3	
	Transportation	0.0	0.2	0.4	0.7	
Methane	Buildings	6.5	4.8	2.0	0.2	
	Industry	4.5	3.6	2.6	1.1	
	Transportation	0.1	0.0	0.0	0.0	

The methane peak demand presented in the tables above is adjusted from the peak demand used in the Guidehouse model to reflect ETSA inputs, such that peak methane demand in 2020 is 121 GW. As noted in footnote 59 of the updated P2NZ Report, this calibration does not affect the model's optimization or the cost results that it produces because the model calculates costs associated with the existing methane system based on energy content, not capacity, and because no new methane infrastructure capacity is built in any scenario considered in this analysis.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

Interrogatory

Reference:

E1/T10/S5/Attachment 2, p. 59 of 86

Question(s):

Guidehouse states that Ontario's existing gas pipeline network "is ideally suited to be repurposed to a hydrogen network, as the province's newer pipelines, typically made of polyethylene, are already largely hydrogen-ready. Metal pipes will require integrity assessments and internal coatings before they can be used to transport hydrogen."

a) What fraction of transmission pipelines in Ontario are the "newer" type, made from polyethylene? Please provide the response in both percentage terms and in kilometer terms.

b) What fraction of distribution pipe in Ontario is made from polyethylene? Please provide the response in both percentage terms and in kilometer terms.

c) Guidehouse's scenarios, particularly the Diversified scenario, appear to rely on both hydrogen and methane (e.g. from RNG). How can the existing gas pipes be repurposed for hydrogen if there is still a need to transport and distribute RNG and other forms of methane? Doesn't this require two sets of pipes? If not, why not?

d) How could existing gas pipes designed to carry methane be repurposed to carry hydrogen fuel that has only ~30% as much energy content per cubic meter. Wouldn't the pipes have to be replaced with versions that are three times the size – or supplemented with significant additional pipe? If not, why not?

Response:

a) There are no transmission pipelines in Enbridge Gas made from polyethylene.

b) Please see Exhibit 2, Tab 6, Schedule 2, Page 81, Table 5.2.3-1: Distribution Pipe Inventory that has been duplicated below. Modern PE accounts for approximately 40% of all pipe (not including service pipe).

Table 5.2.3-1: Distribution Pipe Inventory8				
Asset EGD Rate Zone	**EGD Rate Zone**	**Union Rate Zones**	**Total**	**% Total**
Mains (km)	**42,973**	**44,690**	**87,663**	
TIMP Pipe - Distribution Pipe	341	1,744	2,085	2.4%
TIMP Pipe - Transmission Pipe*	142	1,312	1,454	1.7%
Steel Mains (Pre- and including 1970)	7,292	10,131	17,423	19.9%
Distribution Steel Pipe Post-1970	6,593	8,788	15,381	17.5%
Plastic Pipe - Modern PE	22,763	12,372	35,135	40.1%
Plastic Pipe - Intermediate Plastic Mains	4,721	1,342	6,063	6.9%
Plastic Pipe - Not yet categorized	0	7,893	7,893	9.0%
Plastic Pipe - Vintage Plastic Aldyl A	1,042	1,053	2,095	2.4%
Bare unprotected pipe (km) **	0	136	136	0.2%

c-d) Please see response at Exhibit I.4.2-ED-127.

EXCERPT

c) As provided at Exhibit 1, Tab 10, Schedule 5, page 23, paragraph 73 "It is also important to note that Enbridge Gas believes that the diversified pathway outlined in the P2NZ Study is just one version of what a diversified pathway could look like; there are many different permutations of how it could unfold in Ontario. Enbridge Gas believes that to develop the most optimal diversified pathway, that it must work closely with the electricity sector to undertake an integrated approach to energy transition modeling and planning." It is for this reason that Enbridge Gas has not yet defined exactly what a diversified scenario would mean for each sector and for each part of its system. At a high-level, however, Enbridge Gas would define a diversified pathway as one where energy choices are not mandated by government policy, rather customers have the ability to meet emissions reductions targets by making energy choices that meet their affordability, reliability and resiliency requirements. Energy system utilization and build out would respond to customer preferences. The gas system would serve all sectors of the economy including buildings, industrial, transportation, and power generation. Customers would have the choice of natural gas paired with carbon capture utilization and storage (CCUS), low and zero carbon fuels and low carbon electricity. Depending on customer preferences, gaseous fuels could be used to meet year-round requirements, peak season demands, back up for resiliency or not at all. Enbridge Gas believes that the degree to which each sector utilizes the gas system would vary by region, as each region would leverage and optimize the gas and electric infrastructure in place as well as optimize any required buildouts. Optimization will consider safety, energy system cost, reliability, resiliency, customer choice and maintaining a competitive industry.

delivery be cut off to customers downstream of the conversion until the treatment is completed. What would customers be expected to use to heat water, cook food, etc. while that is happening?

Much more importantly, every methane-burning appliance (furnace, boiler, water heater, stove, dryer, etc.) downstream of the pipe being converted from methane-carrying to 100% hydrogen-carrying would need to have been converted to hydrogen burning before the utility distribution system switch-over occurs. All in-home piping would also have to be hydrogen-ready. Enbridge and its consultants have suggested that this can be accomplished if customers install hydrogen-ready equipment when existing equipment reaches the end of its useful life.[42] While there is no reason to expect that result to naturally emerge in the market, government policy could require all new gas-burning appliances (and the in-home piping serving them) to be "hydrogen-ready". However, there are at least three major problems with that vision.

- First, it is important to recognize that "hydrogen-ready" does not mean that a furnace or water heater or cooktop can instantaneously switch from burning methane to burning hydrogen. There are components of each appliance that will need to be switched at the time of conversion from methane pipe to 100% hydrogen pipe. That will require going into every home and business to make such conversions. How would Enbridge ensure it could even get into every home and business?
- Second, gas furnaces have an average measure life of about 18 years and gas boilers have an average measure life of 25 years.[43] Importantly, those are *averages*. Some furnaces last 25 to 30 years and some boilers last longer than that. Thus, even if government required all new gas-burning appliances to be hydrogen-ready as early as 2025, it is unlikely that *all* gas-burning appliances in a given community or neighborhood will be hydrogen-ready before 2050 if we relied exclusively on natural equipment turnover to reach that state. If we do not rely on natural equipment turnover to get to a fully hydrogen-ready state in all homes and businesses, there will be huge costs incurred to encourage and/or force customers to replace furnaces, boilers and/or other appliances before they planned to do so.
- Third, if Enbridge is prepared to switch a pipe carrying methane to 10,000 or 100,000 homes and businesses to 100% hydrogen, how will it know whether every single one of the tens or hundreds of thousands of individual appliances served by that pipe has been replaced with something hydrogen-ready so that it can switch to 100% hydrogen with minimum safety risk?

Another important issue is that, because hydrogen is less dense than methane, a given diameter of pipe can deliver only about 30% as much hydrogen energy as methane energy. That suggests that existing methane pipe could only be used to deliver hydrogen if peak demand from customers connected to the pipe is collectively reduced by 70%.

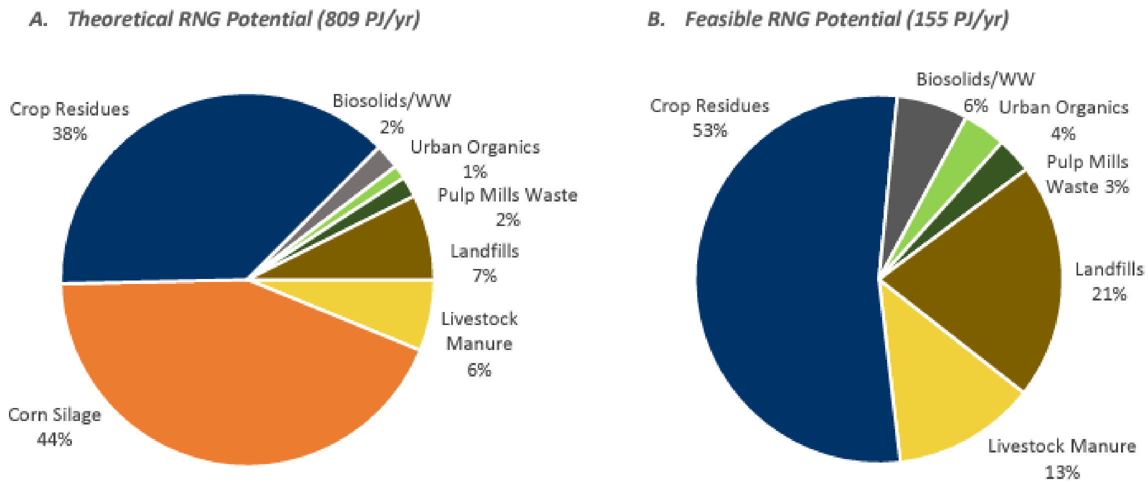
All of this suggests that the only plausible way to deliver 100% hydrogen on a mass scale to residential and small to medium business customers is to build a new hydrogen pipe distribution system in parallel to the existing methane distribution system. That would allow a gradual, customer-by-customer switch

(E1/T10/S5/Attachment 2, p. 60 of 88). However, only about 40% of Enbridge's distribution pipe is made from polyethylene (response to GEC-23b).

[42] Response to SEC-41(b).

[43] These are commonly assumed measure lives in utility DSM programs. For example, see Enbridge EB-2021-0002 Interrogatory Response I.5.EGI.GEC.9_Attachment 2, Tab Union-2019 rows 19 and 20

Figure 31. Theoretical and Feasible RNG Potential in Canada



Source Torchlight (Stephen, Jamie et al. (TorchLight Bioresources), Renewable Natural Gas (Biomethane) Feedstock Potential in Canada, Final Report, funded by Natural Resources Canada, March 2020, p. 56.)

of 240, but the other issue is calling it the potential when it's a theoretical potential. I shouldn't have said anything. I am now getting into a debate, and I should move on to my next questions which are on ED-36.

I understand that Guidehouse's RNG costs are based on a study. In particular, if you scroll down in this response here on page 3, it says that the costs for anaerobic digestion are provided at Table A11, and Guidehouse derived these costs from a 2021 U.S. EPA report.

Could you turn up that U.S. EPA report. I provided it earlier today.

So Mr. Ringo, I assume you are familiar with this report?

MR. RINGO: I'm familiar with the assumptions that we gathered from it.

MR. ELSON: And this is a landfill gas energy project development handbook, correct?

MR. RINGO: Yes.

MR. ELSON: And the figures that you cite come from page 4-3 and 4-10 of this report?

MR. RINGO: Yes.

MR. ELSON: And those are figures for landfill gas, not for an anaerobic digestion facility, correct?

MR. RINGO: They are figures that describe the capital cost of collection of methane, collection and processing of methane at a landfill site.

MR. ELSON: And you'd agree that that's different than the cost of an anaerobic digestion facility?

Table 7: Torchlight Study Estimated RNG Production Costs by Feedstock [83]

Scenario	Feedstock	Specific CapEx ($ M)	CapEx ($/GJ)	Feedstock ($/GJ)	OpEx ($/GJ)	Total ($/GJ)
SW Ontario Corn	Corn Silage & Chicken Litter	20	21.90	7.90	11.80	41.60
Urban Organics & Manure	SSO & Hog Manure	35	38.30	-5.00	20.60	53.90
Prairie Crop Residues	Straw	27.5	30.10	8.50	16.20	54.80
Landfill Gas (best case, upgrader only)	Landfill Gas	2.5	1.85	2.15	2.1	6.10
Landfill Gas (likely)	Landfill Gas	7.5	8.20	3.00	4.40	15.60

Source Ex. M9, p. 32 citing Torchlight p.44

Globe and Mail July 5, 2023

World's largest steelmaker invests in Canadian cleantech startup CHAR Technologies

JAMESON BERKOWCAPITAL MARKETS REPORTER

CHAR Technologies Ltd. has become the first Canadian company to receive funding from the ArcelorMittal Ltd. XCarb Innovation Fund for its efforts to replace coal in steelmaking.

The fund, which the Luxembourg-based steel producer established in 2021 to invest in startups working to remove carbon emissions from the steelmaking process, will spend $6.6-million on 11 million of CHAR's TSX Venture Exchange-listed shares for 60 cents each, the companies announced Wednesday. ArcelorMittal will also be entitled to appoint one director to the Canadian company's board and will have the option to purchase an additional 2.75 million of its shares for 70 cents each over the next 24 months as part of the deal.

While the amount itself is small relative to ArcelorMittal's roughly $30-billion market value, CHAR chief executive Andrew White said the investment itself represents a major vote of confidence in the young company.

"Having that kind of clear validation that the world's largest steel company has investigated what we are doing and wants to invest, that is a very key milestone for us," Mr. White said in an interview.

Using a technology called high temperature pyrolysis, CHAR is able to turn forestry waste products (the parts of the tree that lumber companies would otherwise throw away) into various renewable energy products including biocoal, which can replace metallurgical coal in steelmaking. The process is autothermal, meaning no external heat sources are required and excess energy is created, thereby making the final product carbon-negative.

CHAR has been working with Hamilton-based Dofasco – which is owned by ArcelorMittal – since 2017 to produce replacements for their metallurgical coal.

Steelmaking is one of the most carbon-intensive activities on the planet, producing nearly one-10th of all greenhouse-gas emissions globally. Many producers – Dofasco among them – are in the process of switching from traditional blast furnaces to electric arc furnaces, which have been shown to reduce emissions by roughly 75 per cent.

"Going from a blast furnace to an electric arc furnace also means you drastically reduce the amount of metallurgical coal you need," Mr. White said. Switching to an arc furnace brings the amount of coal required down to a scale where CHAR can produce enough biocoal “to 100-per-cent replace what they are using now.

ArcelorMittal has pledged to become carbon-neutral by 2050 and according to Irina Gorbounova, the company’s vice-president of mergers and acquisitions, the XCarb fund is playing a critical role in seeing that goal achieved.

“We want to see if there are any interesting, disruptive and game-changing technologies that can accelerate our journey to net zero,” Ms. Gorbounova said in an interview from London. “One of the technologies [we want] is exactly around what CHAR is doing, finding a way to replace fossil coal in our operations.”

Much of the investment will go towards CHAR’s facility in Thorold, Ont., which is set to begin production in early 2024. Dofasco already has an agreement to buy the first 5,000 tonnes of annual production from the Thorold facility.

“One interesting thing about Thorold is that it will be a mix of forest byproduct and forestry residuals,” Mr. White said. “We are going to be able to get about half of the feedstock that we need from used shipping pallets.”

Gaining support from XCarb was no small feat, as Ms. Gorbounova said the fund has been “bombarded by lots of various proposals from different countries” since it launched more than two years ago and the pace has yet to slow down.

“Like, in the last 24 to 48 hours alone we must have received 15 to 20 proposals,” she said.

Despite that volume, the fund has invested US$160-million in just seven companies globally to date. Several of those companies have already received a second round of funding from XCarb.

“Normally when we invest we do follow” with another round of funding, Ms. Gorbounova said, “though it is still on a case-by-case basis, it is usually the strategy.”

In the meantime, Mr. White is confident his company’s product can scale to the point where it is realistically possible to remove metallurgical coal from steelmaking. Factoring in the cost of carbon emissions, which must be paid when using metallurgical coal but not when using biocoal, Mr. White said CHAR is cost-competitive

“Could we replace all the met coal used in Eastern Canada? Putting aside any remaining blast furnaces, because their consumption is just so high, I think the answer is absolutely.”

Excerpt from Ex.M9 (EFG)

those customers' distribution charges until after 2050.[110] If the new customer converts to all-electric buildings 10 or 15 years from now, the capital cost of having connected them to the Enbridge system will not have been fully recovered under current connection rules, creating a stranded asset that customers still on the gas system will have to pay. Even if they stay just long enough to pay off their individual connection costs, they would have had a "free ride" by not contributing any costs to the overall system beyond their own service line and meter.

C. Require All New Connections to Be Net-Zero GHG

From a public policy perspective, there are compelling arguments for a moratorium on new gas connections. Indeed, the state of New York just enacted legislation that would ban the use of fossil gas and other fossil fuels in most new buildings.[111] An alternative to a new connections moratorium would be to require that (1) all new gas connections be heated with hybrid systems comprised of cold climate electric heat pumps with gas furnaces used only for back-up heat on the coldest hours and days of the year; and (2) all of the gas supplied on those coldest hours and days of the year will be net-zero GHG-emitting with the new customers bearing the full cost of that more expensive gas (i.e., without cross-subsidies from existing gas customers).

Energir, the Quebec gas utility, recently announced that it will seek approval in its next rate case for a similar, though less restrictive policy. It would give potential new customers the option of either a 70% electric / 30% RNG option or a 100% RNG option.[112] Given the significant limitations on RNG availability, it would be more prudent to limit this offer, at least for residential and commercial buildings, to cold climate electric heat pump-gas furnace systems in which the electric heat pump delivers much more than 70% of heating needs – probably 90% or more – in most of Ontario.

2. Align Depreciation and Rate Design with Expectation of Declining Gas Throughput

The proposed approach to depreciation is highly problematic because it does not address decarbonization risks at all and implicitly assumes a 0% risk of underutilized or stranded assets even long past 2050. Given the almost certain inter-generational inequities that will arise from decarbonization of the gas system in Ontario under the Company's current or proposed approach to asset depreciation, the Board should consider and implement alternative approaches. Specifically, the Board should require Enbridge to assess near-term and longer-term rates, costs of capital and inter-generational equity impacts of (1) maintaining its currently proposed Equal Life Group (ELG) depreciation method, (2) adopting an Economic Planning Horizon (EPH) for new assets, (3) adopting an EPH for all assets, and (4) switching to a Units of Production (UOP) method of asset depreciation. That analysis should be performed using load forecasts consistent with the most likely decarbonization pathway or pathways.

The Board should require that Enbridge file this analysis in 2024. It is important that this happen as soon as it reasonably can. The longer we wait, the closer we get to the point when gas sales are likely to decline, reducing the ability to mitigate against inter-generational inequities. Also, the longer we wait, the greater the short-term adverse effect on customers still on the system. For example, Enbridge estimates that adopting a 2050 EPH in 2024 would increase the amount of revenue required to be collected from ratepayers in that year by $257 million, but waiting to adopt a 2050 EPH until 2028 will

[110] JT3.11.
[111] https://www.washingtonpost.com/climate-environment/2023/05/03/newyork-gas-ban-climate-change/.
[112] https://www.energir.com/en/about/media/news/vers-la-carboneutralite-des-batiments/

load increases because of electrification, and we use that base 2020 load shape and then layer the additional load due to electrification on top of that. It's like additional load in that load shape; does that make sense?

MR. NEME: Yes.

MR. RINGO: Does that answer your question?

MR. NEME: And you do that separately for buildings, transportation, and industry?

MR. RINGO: That's right.

MR. NEME: Okay. So for the building's component of that, how did -- you know how much load is being electrified.

It is some combination of space-heating load, water-heating load -- actually, as we just discussed, by 2050 it is 32 out of 71 terawatt-hours for space-heating load, 19 out of 71 of the increase relative to diversified scenario was water heating and the other 19 was a bunch of other stuff.

So how did you -- for the increase relative to the IESO 2020 values for the building sector, let's say in 2030, you know how many terawatt-hours or you can compute how many terawatt-hours of increase you have given on an assumed set of efficiencies from the gas equipment that's being -- would have been used to the electric equipment that's being used instead; is that the starting point?

MR. RINGO: Yes.

MR. NEME: So then you know how many more terawatt-hours you have to add, and now the question is simply, in which seasons and in which hours of the day, and how did you determine that?

MR. RINGO: We used heating degree hours, using, I think, typical meteorological year climate data for, I think it was a weather station in Toronto, since that's the main population centre, and used this load shape that you -- oh, it's not on your screen any more, but the one that you cited, GEC 18.

MR. NEME: GEC 18.

MR. RINGO: Used that performance curve to assess the COP by hour of the year.

MR. NEME: Mm-hmm.

MR. RINGO: Used the heating degree hours, calculated per hour of the year, and developed a normalized load shape based on the air-source heat-pump performance curve. Does that --

MR. NEME: Okay. So what you just described is the development of a load shape for the space-heating electrification; is that fair?

MR. RINGO: Right.

MR. NEME: And then would you have done the same thing for water heating, although perhaps not [audio dropout] sensitive, and the same thing for all other end uses, and then added them all together for the building sector?

MR. RINGO: No, as a simplifying assumption, we used the space-heating load shape and applied that to all electrification loads.

MR. NEME: So you used the space-heating

electrification load shape and applied it to all of the load -- all of the -- so to the extent you had cooking electrification occurring or water-heating electrification occurring, you assumed that the load shape for the water-heating electrification is the same as for the space-heating electrification?

MR. RINGO: There was a simplifying assumption that we used. We did not have separate load shapes by end use.

MR. NEME: Doesn't -- but is it fair to say that water-heating, drying, cooking, just given your personal knowledge, is much less peaky or will impact the peak hour relative to -- the percentage of demand for each of those end uses on the peak hour will tend to be much lower than it is for space heating, because they are not climate-driven, their consumption is not climate-driven?

MR. RINGO: I haven't modelled those load shapes, so I can't answer that question.

MR. NEME: Okay. Okay. Thank you, that's helpful.

Can we go to GEC 28. So this is a -- if we could scroll a little further down. Thank you.

So in this response you provided for 2030 a breakdown of the energy efficiency load reductions that you forecast and where they are coming from in four different buckets.

I want to focus on the third, the improvements to residential building envelopes, where you show in the diversified scenario that you would get 1.4 petajoules per year and in the electrification scenario 2.6 petajoules per year.

For more information, please get in touch with one of the 13 Gas for Climate member organisations:

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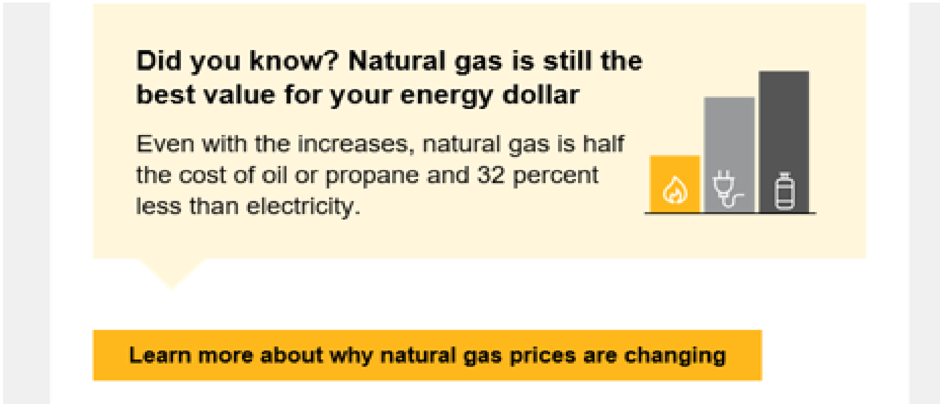
NEWS

Guidehouse Launches Building the Clean Hydrogen Economy Consortium

Guidehouse is leading a group of regional and global players to drive hydrogen pilots focused on heavy transport, renewables integration, and industrial applications

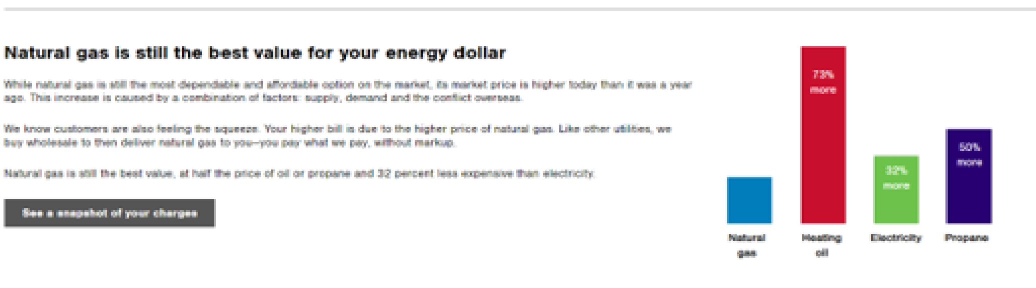
FEBRUARY 25, 2022

https://guidehouse.com/news/energy/2022/guidehouse-building-clean-hydrogen-consortium?lang=en



Source: EGI email campaign Feb. 8, 2023

https://spring-oreo.itracmediav4.com/view?uuid=f497419a-fb60-4403-86ff-7dc4309a7f54



Source: "Learn more..." Link in EGI Feb. 8, 2023 email:

https://www.enbridgegas.com/gas-rates-notice?utm_source=iTrac&utm_medium=eBlast&utm_campaign=ENB_1156_iTrac_eBlast_Jan2023&utm_id=ENB_1156&utm_content=Learn_more

*Based on 2,400 m^3 annual consumption.
Notes: Natural gas prices are based on Rate 1 rates in effect as of April 1, 2023. Oil and propane prices are based on the latest available retail prices. Electricity rate based on Toronto Hydro rates as of Jan. 1, 2023 and RPP customers that are on TOU pricing. It includes the new Ontario Electricity Rebate (OER). Costs have been calculated for the equivalent energy consumed and include all service, delivery and energy charges. Federal carbon price is included for all energy types as reported. HST is not included.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

Interrogatory

Reference:

Ex.4, Tab 5, S1, Attachment 2, p. 19 of 451

Question(s):

Regarding the basis for adoption of an Economic Planning Horizon (EPH):

a) Is it Concentric's view that there must be an expectation of retirement of assets in order to justify an EPH? If so, why?

b) If assets are not expected to be retire, but are expected to serve significantly fewer customers, isn't there an inter-generational argument for placing more of the cost recovery burden on current customers (when there are many more of them using an asset) and less on future customers (when there are considerably fewer of them)? If not, why not?

c) If the number of customers expected to use an asset is expected to decline significantly over time, wouldn't an EPH improve inter-generational equity by placing more of the cost recovery burden on early years when there is greater use of the asset? If not, why not?

d) Are there other forms of adjustment to cost recovery, other than an EPH, that Concentric believes would more effectively address the inter-generational equity issues raised in parts "B" and "C" of this question? If so, what are they? Please describe them in detail, with references to how and where they are used today (if any).

Response:

The following response was provided by Concentric:

a) All depreciable investment will retire at some point in time. The use of an EPH is implemented into depreciation rates when it is expected that large groups of assets will retire simultaneously due to causes of retirement other than physical wear and tear or deterioration. Additionally, a reasonable determination of the timing of the simultaneous retirement is also required.

b) Concentric agrees that any customer or customer group should only be responsible for the consumption of the service value of the assets that they have access to. As such, in the circumstance where the demand on a gas distribution system decline, generational fairness would indicate that the remaining net book value of the system to be recovered from the later customers would be consistent with the system that had largely been consumed by earlier users when the system was operating at higher capacity levels.

c) While intergenerational equity would require that the original cost of investment of an asset is recovered by the customers who gain the benefit of the assets, in the current circumstances of Enbridge Gas, an EPH is not the appropriate mechanism to recover this investment in the case of a substantial reduction in customer load. This is because an EPH depreciates the entire asset value over a reduced time frame. As such, there is no ability to retain investment in a particular account for customers who maintain service beyond the end of the economic date. However, in the circumstances when it can be estimated that significant assets would be retired at various capacity levels, an EPH could be established for that specific group.

d) The use of the Equal Life Group (ELG) procedure in the depreciation rate calculation will deal with the issue identified in this question. The ELG procedure recognizes that all retirement of investment will not occur in a linear fashion and specially adjusts for the retirement of some investment at younger ages. In part, it is for this reason that Concentric has recommended the use of the ELG procedure in this application.

Concentric is aware of a recurrence in the consideration of the use of the Units of Production method of depreciation to deal with this issue. While Concentric has not recently recommended the use of Unit of Production, it is a depreciation tool that could be considered in future applications.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

Interrogatory
Reference:
E1/T10/S4, pp. 17-18
Question(s):

Enbridge has suggested that an Economic Planning Horizon (EPH) for depreciating assets “is not appropriate at this time” because of uncertainty about how the energy transition would affect its system, but that “if a diversified pathway to net-zero is not adopted in Ontario, Enbridge Gas would seek to introduce an EPH on its system to mitigate the risk of stranded assets.” Enbridge further states that “if a system-wide 2050 EPH were to be implemented starting 2024, the 2024 Test Year depreciation expense would increase by $282 million, from $921 million to $1.2 billion.”

a) Why is uncertainty about how the energy transition will affect Enbridge’s system a reason not to adopt an EPH? Doesn’t the uncertainty about the impacts of the energy transition create risk for future ratepayers which an EPH can mitigate? In other words, isn’t an EPH, at least in part, a ratepayer risk mitigating strategy? If not, why not?

b) Would Enbridge agree that there will always be uncertainty about the impacts of the energy transition twenty or more years into the future? If so, does that mean Enbridge would never find it appropriate to put an EPH in place? If not, please explain in detail how much “certainty” there must be for Enbridge to support adoption of an EPH?

c) How does Enbridge define a “diversified pathway to net-zero”? Please be specific about exactly what features a pathway would need to have to be considered by Enbridge to be “diversified”. Is there a minimum or maximum amount of gaseous energy throughput through Enbridge’s system? Is there a minimum or maximum amount of peak hour demand to be served by Enbridge?

d) What information would Enbridge need to have that it does not currently have in order to propose an EPH? Put another way, please provide the specific conditions under which Enbridge would pr

e) Would Enbridge agree that there is at least a significant possibility that Ontario's pathway to decarbonization will involve significantly lower annual volumes of gas distributed by the Company? If not, why is that not at least a significant possibility?

f) Is the estimated increase in 2024 Test Year depreciation expense of $282 million associated with the application of an EPH to all assets, both (1) those for which capital investments have already been made but not yet fully depreciated and (2) new assets? If so, what would the 2024 Test Year depreciation expense increase be if a 2050 EPH was just applied to new capital investments?

g) Please provide an Excel file, with formulae intact, showing the actual calculation of the $282 million increase in 2024 Test Year depreciation expensive associated with adoption of a 2050 EPH.

<u>Response:</u>

a) Enbridge Gas agrees that an EPH is appropriate as a risk mitigation strategy to address energy transition. However, the Company is not proposing to incorporate this assumption into the depreciation rates at this time as there is not enough known regarding the impacts of energy transition on the system and the impact of implementing an EPH is significant to rate payers. This view is also supported by Concentric and is provided at Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 19. It may not be appropriate to apply the EPH scenario to all of the utility assets; however, which assets will actually be impacted is not yet determinable. In addition, climate and energy transition legislation is still evolving and there are no specific programs in place that would provide guidance as to future utilization levels of Enbridge Gas's assets. Concentric recommends, and Enbridge Gas supports, that an additional study of changes is required prior to implementation of an EPH and will re-evaluate applying an EPH in future studies.

b) Enbridge Gas agrees that there will continue to be uncertainty about the impacts of energy transition in the future, but that does not necessarily mean that it would never be appropriate to implement an EPH. The Company will reassess the need to implement an EPH at the next depreciation study and will look for 'sign posts' such as government policy changes or commitments from municipalities to convert to alternative fuels to determine what an appropriate EPH might be. If implemented in the next study, the EPH assumptions would be revisited in subsequent studies and as more certainty regarding future usage of assets is known, depreciation rates would be adjusted to either reflect an acceleration due to faster transition or decreased to reflect the lengthening of asset lives.

c) As provided at Exhibit 1, Tab 10, Schedule 5, page 23, paragraph 73 “It is also important to note that Enbridge Gas believes that the diversified pathway outlined in the P2NZ Study is just one version of what a diversified pathway could look like; there are many different permutations of how it could unfold in Ontario. Enbridge Gas believes that to develop the most optimal diversified pathway, that it must work closely with the electricity sector to undertake an integrated approach to energy transition modeling and planning.” It is for this reason that Enbridge Gas has not yet defined exactly what a diversified scenario would mean for each sector and for each part of its system. At a high-level, however, Enbridge Gas would define a diversified pathway as one where energy choices are not mandated by government policy, rather customers have the ability to meet emissions reductions targets by making energy choices that meet their affordability, reliability and resiliency requirements. Energy system utilization and build out would respond to customer preferences. The gas system would serve all sectors of the economy including buildings, industrial, transportation, and power generation. Customers would have the choice of natural gas paired with carbon capture utilization and storage (CCUS), low and zero carbon fuels and low carbon electricity. Depending on customer preferences, gaseous fuels could be used to meet year-round requirements, peak season demands, back up for resiliency or not at all. Enbridge Gas believes that the degree to which each sector utilizes the gas system would vary by region, as each region would leverage and optimize the gas and electric infrastructure in place as well as optimize any required buildouts. Optimization will consider safety, energy system cost, reliability, resiliency, customer choice and maintaining a competitive industry.

d) Enbridge Gas notes that this question is incomplete and is replying in terms of the first sentence in the question. As described in part a), Enbridge Gas would need to have more data to support the expected changes in utilization to a more specific subset of system assets. For example, a change in utilization for distribution as compared to transmission or storage assets.

e) Enbridge Gas would agree that Ontario’s pathway to decarbonization could involve lower annual gas volumes as a result of continued focus on energy efficiency, the uptake of technologies like hybrid heating and some from fuel-switching away from gaseous fuels. It does not, at this point, however, agree that this is a significant possibility, due to two key reasons. First, natural gas consumption could be replaced with the consumption of RNG and hydrogen, and second some larger customers could maintain their current natural gas consumption and pair it with CCUS, and others could increase their consumption of natural gas as they move away from higher emitting fuels to natural gas as part of their long-term plan to transition to hydrogen.

f) Please note that the impact of applying the 2050 EPH scenario to the 2024 Test Year depreciation expense has been updated to $290 million, please see Exhibit 1, Tab 10, Schedule 4, page 18, updated March 8, 2023.

The rates are applied to total balances which would include assets that are not yet fully depreciated. Enbridge Gas is unable to calculate the 2024 Test Year depreciation expense if the 2050 EPH was only applied to new capital investments due to the nature of the depreciation forecasting models used.

g) Please see response at Exhibit I.4.5-LPMA-34 Attachment 1.